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Decision 15-12-025 December 17, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

DECISION ACCEPTING DRAFT 2015 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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2015 RPS Plans
Acronym List

Acronym	Term
A	Application
AB	Assembly Bill
AC	Alternating Current
ACR	*Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review of 2015 Renewables Portfolio Standard Procurement Plans* issued May 28, 2015
ADS	Automated Dispatch System
AL	Advice Letter
ALJ RNS Ruling	*Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014
API	Application Programming Interface
ASC	Accounting Standards Codification
BioMAT	Bioenergy Market Adjusting Tariff
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CBA	California-based Balancing Area Authority (SDG&E); California Balancing Authority Area (SCE)
CCA	Community Choice Aggregator
CEC	California Energy Commission
CHP	Combined Heat and Power
COD	Commercial Operation Date
CP	Compliance Period
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPUC	California Public Utilities Commission

CRE	Customer Renewable Energy FiT
CSIAL	Customer-Side Implementation Advice Letter
D.	Decision
DA	Direct Access
DBE	Diverse Business Enterprise
DC	Direct Current
DG	Distributed Generation
DGD	Distributed Generation Deliverability
DRA/ORA	Division/Office of Ratepayer Advocates
ECR	Enhanced Community Renewables
EE	Energy Efficiency
EPC	Engineering, Procurement, and Construction
ESP	Electric Service Provider
FCDS	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
FFO	Funds from Operations
FIT	Feed-In Tariff
GAAP	Generally Accepted Accounting Principles
GCOD	Guaranteed Commercial Operation Date
GHG	Greenhouse Gas
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GT	Green Tariff

GTSR	Green Tariff Shared Renewables Program
gWh	Gigawatt-hours
HVDC	High Voltage Direct Current
IDWA	Irrigation District and Water Agency
IE	Independent Evaluator
IID	Imperial Irrigation District
IID STEP	Imperial Irrigation District Strategic Transmission Expansion Plan
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRC	Internal Revenue Code
ITC	Investment Tax Credit
IV	Imperial Valley
JPIAL	Joint Procurement Implementation Advice Letter
kV	Kilo-volt
kWh	Kilowatt-hour
LCBF	Least-Cost Best-Fit
LCR	Local Capacity Requirement
LMP	Locational Marginal Price
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MACRS	Modified Accelerated Cost Recovery System
MIAL	Marketing Implementation Advice Letter
MVI	Motor Vehicle Incident
MW	Megawatt
NDA	Non-Disclosure Agreement

NERC	North American Electric Reliability Corporation
NMV	Net Market Value
NPV	Net Present Value
NQC	Net Qualifying Capacity
OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
OTC	Once-Through Cooling
PAV	Portfolio Adjusted Value
PBR	Portfolio Balance Requirement
PCC	Portfolio Content Categories
PEL	Procurement Expenditure Limitation
PG&E	Pacific Gas and Electric Company
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PQR	Procurement Quantity Requirement
PRG	Procurement Review Group
PRP	Preferred Resources Pilot
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PV	Photovoltaic
QF	Qualifying Facility
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff

RFI	Request for Information
RFO	Request for Offers
RFP	Request for Proposals
RNS	Renewable Net Short
RPS	Renewables Portfolio Standard
SANS	Stochastically-Adjusted Net Short
S&P	Standard and Poor's
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SONGS	San Onofre Nuclear Generating Station
SONS	Stochastically-Optimized Net Short
SPVP	Solar Photovoltaic Program
TAC	Transmission Access Charge
TOD	Time Of Delivery/Day
TPP	Transmission Planning Process
TRTP	Tehachapi Renewable Transmission Project
TURN	The Utility Reform Network
TWRA	Tehachapi Wind Resource Area
UOG	Utility-Owned Generation
VIEs	Variable Interest Entities
VMOP	Voluntary Margin of Procurement (PG&E); Voluntary Margin of Over-Procurement (SDG&E and SCE)
WATER	Water Agency Tariff for Eligible Renewables FIT

WECC	Western Electric Coordinating Council
WOD	West of Devers
WREGIS	Western Renewable Energy Generation Information System

DECISION ACCEPTING DRAFT 2015 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

Summary

Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1),[1] today's decision accepts, with some modifications, the draft 2015 Renewables Portfolio Standard (RPS) Procurement Plans, including the related solicitation protocols, filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

We direct PG&E, SCE, and SDG&E to file their final 2015 RPS Procurement Plans pursuant to the 2015 RPS solicitation schedule adopted herein.

This decision also accepts the draft 2015 RPS Procurement Plans filed by Bear Valley Electric Service, Calpine PowerAmerica-CA, LLC's, Commerce Energy, Inc., Commercial Energy of California, Constellation NewEnergy, Inc., Direct Energy Business LLC, LLC, EDF Industrial Power Services, LLC, Gexa Energy California, LLC, Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Palmco Power CA, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, Tiger Natural Gas, Inc., and 3 Phases Renewables, Inc.

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[1] Pub. Util. Code § 399.13(a)(1) states: "The commission shall direct each electrical corporation to annually prepare a renewable energy procurement plan that includes the matter in paragraph (5), to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary."

This proceeding remains open.

1. Procedural Background

The Order Instituting Rulemaking (OIR) for this proceeding was adopted by the Commission on February 26, 2015. Comments on the preliminary scoping memo in the OIR were filed and served on or before March 26, 2015, by 25 parties.[2] Reply comments were filed and served by 11 parties on April 6, 2015.[3]

A Prehearing Conference (PHC) was held on April 16, 2015. Twenty PHC statements were filed and served by a total of 26 parties.[4]

2. This Proceeding

This OIR is one of a series of proceedings implementing the California renewables portfolio standard (RPS) program. The RPS program was instituted

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[2] Six parties filed comments on March 18, 2015: Alliance for Desert Preservation; Basin and Range Watch; California Desert Coalition; Lucerne Valley Economic Development Association; Mojave Communities Conservation Collaborative; and Morongo Basin Conservation Association. Filing on March 26, 2015 were: Calpine Corporation (Calpine); California Energy Storage Alliance (CESA); California Wind Energy Association (CalWEA); Center for Biological Diversity (CBD); Center for Energy Efficiency and Renewable Technologies (CEERT); Clean Coalition; Green Power Institute; Large-Scale Solar Association (LSA); The Nature Conservancy, Defenders of Wildlife, and Natural Resources Defense Council (jointly); Noble Americas Energy Solutions LLC; Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); L. Jan Reid (Reid); San Diego Gas & Electric Company (SDG&E); Sierra Club; Southern California Edison Company (SCE); and Union of Concerned Scientists (UCS).

[3] They are: CalWEA; CBD; Imperial Irrigation District; Independent Energy Producers Association (IEP); PG&E; Reid; Sacramento Municipal Utility District (SMUD); Shell Energy North America (US), L.P.; Sierra Club; SCE; and Utility Consumers Action Network (UCAN).

[4] They are: Bay Area Municipal Transmission Group, and City and County of San Francisco (jointly); Bioenergy Association of California; Calpine; CalWEA; CEERT; CESA; Clean Coalition; IEP; LSA; Marin Clean Energy; The Nature Conservancy, Defenders of Wildlife (jointly); PG&E; Pacific Power, Bear Valley Electric Service, and Liberty Utilities (jointly); ORA; Reid; SCE; SDG&E; Sierra Club, UCS, and CBD (jointly); SMUD; and UCAN.

by Senate Bill (SB) 1078 (Sher), Stats. 2002, ch. 516. The Legislature has made numerous alterations, both major and minor, to the RPS program over the years. The RPS statute is currently codified at Pub. Util. Code §§ 399.11-399.32.[5]

Many elements of the RPS program are continuous, such as review and approval of RPS procurement plans; review of the contracts of investor-owned utilities (IOUs) for RPS procurement; review of retail sellers' compliance with their RPS procurement obligations;[6] review and revision of analytic tools that can improve the value of the RPS program and streamline its administration; and coordination across Commission proceedings and with other agencies. Some elements of the program are addressed only intermittently, such as incorporation of legislative changes to the RPS statute, or potential enforcement action when a retail seller does not comply with its RPS procurement obligations.

This proceeding provides a home for all the elements of the ongoing administration of the RPS program that require recognition or action in a formal Commission proceeding.[7] This proceeding is also the current vehicle for exploring additional development of the RPS program, including but not limited to:

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[5] All further references to sections are to the Public Utilities Code, unless otherwise specified.

[6] "Retail sellers" include IOUs, community choice aggregators, and electric service providers. *See* Section 399.12(j).

[7] Energy Division staff maintain an informal but comprehensive compilation of all RPS program activities and documents on the Commission's web site, at http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm.

- setting RPS procurement percentages greater than 33% of retail sales of RPS-obligated retail sellers;[8] and
- considering whether and how to integrate greenhouse gas (GHG) reduction goals in the RPS program.

3. Scope of Issues

After considering the parties' written comments on the OIR and their PHC statements, as well as the discussion at the PHC, and factoring in the many ongoing tasks for this proceeding, the following issues were identified for the scope of this proceeding:

- Exercise (or not) the Commission's authority under AB 327 to set RPS procurement requirements greater than 33% of retail sales of RPS-obligated retail sellers;[9]
- Revise and further develop the functionality of the RPS Calculator;[10]
- Revise and update the least-cost best-fit (LCBF) methodology for evaluating RPS-eligible procurement, including any revisions mandated by SB 2 (1X) (Simitian), Stats. 2011 ch.1, that have not yet been implemented;
- Complete work on a final methodology for calculating renewable integration cost (IC) adder(s);[11] and

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[8] *See* Assembly Bill (AB) 327 (Perea), Stats. 2013, ch. 611. Effective January 1, 2016, the RPS procurement percentages will increase as a result of the enactment of Senate Bill 350, discussed, *infra*, in this decision.

[9] This topic will be addressed through the Assigned Commissioner's Ruling Requiring Submission of 2015 RPS Procurement Plans.

[10] For a recent review of the status of the RPS Calculator, see Administrative Law Judge's Ruling Seeking Post-Workshop Comments (April 13, 2015).

[11] The Commission adopted a methodology that it denominated as "interim" in Decision (D.) 14-11-042. That decision also identified a process for developing a final methodology, beginning with general work on integration costs in the LTPP proceeding, which could then be used to develop a final methodology that includes issues specific to RPS procurement, in this proceeding. *(See* D.14-11-042 at 63-65.)

- Begin consideration of integrating goals and metrics for reducing the emission of greenhouse gases into RPS procurement processes and evaluation.

4. Consideration of a Higher RPS Requirement and the Passage of SB 350

The OIR was preliminarily scoped to explore increasing the RPS procurement requirement pursuant to authority given to the Commission by AB 327 (Perea), Stats. 2013, ch. 611. In addition, in January 2015, Governor Edmund G. Brown Jr. expressed plans to increase the amount of renewable energy to address the state's GHG education goals and, on April 29, 2015, issued Executive Order B-30-15 to further reduce GHG emissions. As a result, the parties were instructed as part of this year's RPS Procurement Plans to consider both the current procurement quantity requirements, as implemented in D.11-12-020, and the following increased requirements.

Table 1: Higher RPS Requirement

Compliance period	Procurement percentage
2021	33%
2022	37%
2023	37%
2024	40%

Therefore, all draft 2015 RPS Plans were required to include responses to the *Specific Requirements for 2015 RPS Procurement Plans* (Section 6), considering both a 33 percent by 2020 requirement and a 40 percent by 2024 requirement.

We acknowledge that after the parties submitted their 2015 RPS Plans, Governor Brown signed SB 350 (de Leon) on October 7, 2015. Known as the Clean Energy and Pollution Reduction Act of 2015, SB 350 increased the RPS target from 33% by 2020 to 50% by 2030, with interim targets of 40% by the end of 2024, and 45% by the end of 2027.

Since the 2015 RPS Plans do not directly incorporate SB 350's requirements, in 2016 we will address the implementation of SB 350's higher RPS targets.

5. Requirements by Utility

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

SB 2 1X revised the RPS procurement requirements for multi-jurisdictional utilities and their successors[12] to allow these utilities to meet their RPS procurement obligations without regard to the portfolio content category limitations in § 399.16.[13] It also continued the ability of a multi-jurisdictional utility, i.e., PacifiCorp, 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 § 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 filed its 2015 IRP on March 31, 2015 and its "on year" supplement to its 2015 IRP on April 30, 2015. Pursuant to D.11-04-030, PacifiCorp will not file a comprehensive supplement this year because it filed its IRP this year.

Liberty Utilities LLC, on the other hand, does not prepare an IRP because it is not subject to the jurisdiction of another state. It, therefore, prepared an

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[12] PacifiCorp is a multi-jurisdictional utility for RPS purposes. Liberty Utilities LLC is a successor entity under § 399.17 and not a multi-jurisdictional utility because it has customers only in California.

[13] Section 399.17(b).

RPS Procurement Plan subject to the same requirements as a small utility under § 399.18.

5.2. Utilities Subject to Pub. Util. Code § 399.18

SB 2 1X makes special provisions for the two small utilities existing at the time the legislation was drafted.[14] Section 399.18(b) allows a small utility to meet the RPS procurement obligations without regard to the portfolio content category limitations in § 399.16.

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

Accordingly, BVES, as well as Liberty Utilities LLC, prepared an RPS Procurement Plan providing the information required in Sections 6.1 through 6.6, 6.8, and 6.13 through 6.15 of the May 28, 2015 assigned Commissioner's Ruling.

5.3. Electric Service Providers (ESP)

As provided in D.11-01-026, ESPs must file RPS Procurement Plans. Many of the requirements of § 399.13(a)(5) do not reasonably apply to ESPs because the Commission does not set their rates or rates of return. Therefore, each ESP was required to file an RPS Procurement Plan that complied with a limited set of requirements. 3 Phases Renewables, Inc., Calpine PowerAmerica-CA, LLC's, Commerce Energy, Inc., Commercial Energy of California, Constellation NewEnergy, Inc., Direct Energy Business LLC, LLC,

[14] Section 399.18(a)(1) describes Bear Valley Electric Service (BVES); § 399.18(a)(2) describes the former Mountain Utilities. Mountain Utilities was purchased by Kirkwood Public Utility per D.11-06-032. Mountain Utilities is no longer considered a retail seller subject to the Commission's RPS jurisdiction.

EDF Industrial Power Services, LLC, Gexa Energy California, LLC, Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Palmco Power CA, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc. filed 2015 RPS Plans. Aegra Energy, LLC, Direct Energy Services, EnerCal (dba Yep Energy), Glacial Energy of California, Inc., and Mansfield Power and Gas did not file required 2015 RPS Procurement Plans.

6. Specific Requirements for 2015 RPS Procurement Plans

The assigned Commissioner required that the 2015 RPS Procurement Plans include all information required by statute as well as quantitative analysis supporting the retail seller's assessment of its portfolio and future procurement decisions. The assigned Commissioner's Ruling Identifying Issues and Schedule of Review of 2015 Renewables Portfolio Standard Procurement Plans (ACR), issued on May 28, 2015, identified the following information for inclusion in the 2015 Procurement Plans:

- Assessment of RPS Portfolio Supplies and Demand (Section 6.1);
- Project Development Status Update (Section 6.2);
- Potential Compliance Delays (Section 6.3)
- Risk Assessment (Section 6.4);
- Quantitative Information (Section 6.5);
- "Minimum Margin" of Procurement (Section 6.6);
- Bid Solicitation Protocol, Including Least-Cost Best-Fit Methodologies (Section 6.7);
- Consideration of Price Adjustment Mechanisms (Section 6.8);
- Economic Curtailment (Section 6.9);
- Expiring Contracts (Section 6.10);

- Cost Quantification (Section 6.11);
- Imperial Valley (Section 6.12);
- Important Changes to Plans Noted (Section 6.13);
- Redlined Copy of Plans Required (Section 6.14); and
- Safety Considerations (Section 6.15).

Responses to all sections, except Sections 6.5 and 6.9, were required to provide qualitatively in writing. Responses to Section 6.5 were required to provide a numerical/quantitative format to support the written responses to Sections 6.1 - 6.4, and 6.6. The information in the Procurement Plans were to be non-confidential, to the greatest extent possible, and all sources of information were required to be identified with citations, if any. All assumptions underlying these responses were required to be clearly stated.

When filed with the Commission, all of the proposed 2015 RPS Procurement Plans were required to achieve the following:

1. Describe the overall plan for procuring RPS resources for the purposes of satisfying the RPS program requirements while minimizing cost and maximizing value to ratepayers. This includes, but is not limited to, any plans for building utility-owned resources, investing in renewable resources, and engaging in the sales of RPS eligible resources.
2. The various aspects of the plans themselves must be consistent. For instance, the bid solicitation protocol should be consistent with any statements and calculations regarding a utility's RNS position.[15]
3. The plans should be complete in describing and addressing procurement (and sales) of RPS eligible resources such that the Commission may accept or reject proposed contracts

[15] As of the date of this ruling, the methodology can be found at the May 21, 2014 ruling, *Administrative Law Judge's Ruling on Renewable Net Short*.

based on consistency with the approved plan, including any calculation of RPS procurement net short position.[16]

4. IOUs should work collaboratively to make the format of the plans as uniform as possible to enable parties, bidders, and the Commission to easily access, review and compare the plans.
5. All plan elements should comply with the requirements set out in Section 2.1.

7. PG&E's 2015 RPS Plan

7.1. Summary of RPS Position

PG&E projects that under both the current 33% RPS by 2020 target, as well as a 40% by 2024 scenario, it is positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods, and will not have incremental procurement need until at least 2022.[17]

7.2. Assessment of RPS Portfolio Supplies and Demands

Based on preliminary results presented in its Appendix C.2a, PG&E claims it delivered 27.0% of its power from RPS-eligible renewable sources in 2014.[18]

Under the current 33% RPS target, PG&E projects that it will not have incremental procurement need until at least 2022.[19] Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:

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[16] Section 399.13(d).

[17] PG&E's 2015 RPS Plan at 1.

[18] *Id.*

[19] *Id.*

- 33% of combined bundled retail sales in 2021;
- 37% of combined bundled retail sales in 2022;
- 37% of combined bundled retail sales in 2023; and
- 40% of combined bundled retail sales in 2024 and each year thereafter.

Therefore, PG&E projects that it is positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods.[20]

7.2.1. Supply

7.2.1.1. Existing Portfolio

PG&E states that its existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes over 8,000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small Feed-in tariff (FIT) contracts for solar photovoltaic (PV), biogas, and biomass generation.[21] This supply provides a foundation for meeting current and future RPS compliance needs, subject to uncertainties that are discussed in greater detail in its 2015 RPS Plan.[22]

7.2.1.2. Impact of Green Tariff Shared Renewables (GTSR) Program

According to PG&E, in 2013, SB 43 (Wolk) enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with

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[20] *Id*. at 7-8.

[21] *Id*. at 9.

[22] *Id*.

generation from eligible renewable energy resources.[23] On January 29, 2015, the Commission adopted D.15-01-051 implementing a GTSR framework, approving the IOUs' applications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.[24]

According to PG&E, the GTSR program will impact PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected; and (2) PG&E's retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. PG&E will implement tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff programs.[25]

As PG&E's renewable portfolio has expanded to meet the RPS goals, PG&E asserts that its procurement strategy has evolved. PG&E's strategy continues to focus on the three key goals of: (1) reaching, and sustaining, the 33% RPS target; (2) minimizing customer cost within an acceptable level of risk; and (3) ensuring it maintains an adequate bank of surplus RPS volumes to manage annual load and generation uncertainty. However, PG&E continues to

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[23] *Id*. at 10.

[24] *Id*.

[25] *Id*.

adapt its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.[26]

7.2.2. Anticipated Renewable Energy Technologies and Alignment of Portfolio with Expected Load Curves and Durations

PG&E states that it does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value (PAV) methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost.[27] Starting in the 2014 RPS RFO, PG&E began utilizing the interim IC adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value (NMV) methodology will be updated to use the values and methodologies of the final IC adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[28]

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[26] *Id*. at 12.

[27] *Id*. at 15.

[28] *Id*.

7.2.3. RPS Portfolio Diversity

PG&E states that its RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis. In PG&E's view, resource diversity is one option to minimize the over generation and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement.

7.3. Project Development Status Update

In its Appendix B of its draft 2015 RPS Plan, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June 17, 2015.[29] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions.

[29] Appendix B includes PPAs procured through the RAM and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has 72 executed AB 1969 PPAs in its portfolio and 29 ReMAT PPAs, totaling 104 MW of capacity. These small renewable FIT projects are in various stages of development, with 60 already delivering to PG&E under an AB 1969 PPA and 11 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

Within PG&E's active portfolio,[30] there are 107 RPS-eligible projects that were executed after 2002. Seventy-six of these contracts have achieved full commercial operation and started the delivery term under their PPAs. Thirty-one contracts have not started the delivery term under their PPAs. Of the 31 contracts that have not started the delivery term under their PPAs with PG&E: 18 have not yet started construction; five have started construction but are not yet online; and eight are delivering energy, but have not yet started the delivery term under their PPAs. Based on its historic experience, PG&E asserts that projects that have commenced construction are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre-construction projects currently in its portfolio to achieve commercial operation under their PPAs.[31]

7.4. Potential Compliance Delays

7.4.1. Project Financing

In PG&E's perspective, the financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital and a variety of ownership structures for project developers. However, for renewable technologies that are less proven, less viable, or reflect a higher risk profile, the financing environment is more constrained, with higher costs of capital and fewer participants willing to lend or invest.

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30 PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and CPUC-approved as of June 17, 2015, not including amended post-2002 QF contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation (UOG) projects, or FIT projects.

31 PG&E's 2015 RPS Plan at 19-20.

7.4.2. Siting and Permitting

PG&E states that it works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the development of energy resources in the California desert and other suitable locations. PG&E believes that long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.[32]

7.4.3. Transmission and Interconnection

PG&E observes that delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.[33]

7.4.4. Curtailment of RPS Generating Resources

In PG&E's view, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may present an RPS compliance challenge. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables

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[32] PG&E's 2015 RPS Plan at 23.

[33] *Id*.

PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed.[34]

7.5. Risk Assessment

Dynamic risks directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales variability and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute.[35] These results serve as the primary inputs into the stochastic model, which accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk.

7.5.1. Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) **Standard Generation Variability:** the assumed level of deliveries for categories of online RPS projects.

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[34] *Id*. at 24-25.

[35] *Id*. at 25.

2) **Project Failure:** the determination of whether the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) **Project Delay:** the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

Table 6-1
Pacific Gas and Electric Company
Deterministic Model Risks

RISK	METHODOLOGY	APPLIES TO
Standard Generation Variability	• For non-Qualifying Facility (QF) projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, utility-owned generation (UOG) and IDWA generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/Under Development Projects/Approved Mandated Programs

7.5.2. Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio. PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) **Retail Sales Variability:** This demand-side variable is one of the largest drivers of PG&E's RPS position.
2) **Project Failure Variability:** Considers additional project failure potential beyond the "on-off" approach in the deterministic model.
3) **Curtailment:** Considers buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment.
4) **RPS Generation Variability:** Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.[36]

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year-to-year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

[36] *Id*. at 30.

Table 6-2[37]
Pacific Gas and Electric Company
Categorization of impacts on RPS Position

	Impact	Categorization
Higher Impact on RPS Position ↕	**1. Retail Sales Variability**: Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and direct access (DA), and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
	2. RPS Generation Variability: Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** *(If an outcome occurs, the effect may only occur for the individual year.)*
Lower Impact on RPS Position	**3. Curtailment:** Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
	4. Project Failure Variability: Lost volume from project failure persists through more than one year.	**Variable and persistent**

7.6. Quantitative Information

7.6.1. Deterministic Model Results

Results from the deterministic model under the 33% RPS target are shown as the physical net short in Row Ga of Appendices C.1a and C.2a of its 2015 RPS Plan, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of

[37] *Id.* at 32.

Appendices C.1b and C.2b.[38] Appendices C.1a and C.1b provide a physical net short calculation using PG&E's Bundled Retail Sales Forecast for years 2015-2019 and the LTPP sales forecast for 2020-2035, while Appendices C.2a and C.2b rely exclusively on PG&E's internal Bundled Retail Sales Forecast.[39] Following the methodology described in Section 6.1 of PG&E's 2015 RPS Plan, PG&E currently estimates a long-term volumetric success rate of approximately 99% for its portfolio of executed-but-not-operational projects.[40] The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendices C.2a and C.2b.[41] This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendices C.2a and C.2b depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.[42]

7.6.1.1. 33% RPS Target Results

Under the current 33% RPS target, PG&E is positioned to meet its second (2014-2016) and third (2017-2020) Compliance Period (CP) RPS requirements. As shown in Row Gb of Appendix C.1b of its 2015 RPS Plan, the deterministic model shows a forecasted second CP RPS Position of 30.3% and a third CP RPS

[38] *Id*. at 39.

[39] *Id*.

[40] *Id*. at 39-40.

[41] *Id*. at 40.

[42] *Id*.

position in excess of its RPS requirements.[43] Row Ga of Appendix C.2a also shows a physical net short of approximately 500 gWh beginning in 2022.[44]

7.6.1.2. 40% RPS Scenario Results

Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) CP RPS requirements. As shown in Row Gb of Appendix C.2b of its 2015 RPS Plan, PG&E has a forecasted second CP RPS Position of 30.3% and a third CP RPS position of greater than 34%.[45]

7.6.2. Stochastic Model Results

PG&E has redacted a great deal of the information on confidentiality grounds (a claim no party challenged), making a public discussion of its position difficult. We can state, however, that Appendix C.2a of its 2015 RPS Plan shows detailed results for the 33% RPS target.[46] Figure 7-4 in PG&E's 2015 RPS Plan shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario.[47]

7.7. Minimum Margin of Procurement

PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract).

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[43] *Id.*

[44] *Id.*

[45] *Id.*

[46] *Id.* at 41.

[47] *Id.* at 46.

PG&E considers this deterministic result to be its current statutory margin of procurement.[48]

But PG&E goes further and argues that Pub. Util. Code § 399.13(a)(4)(D) gives an IOU the right to Voluntarily a Margin of Procurement (VMOP) above the statutory minimum margin of procurement. PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.[49] When used as a VMOP, the Bank will help to avoid long-term over-procurement above the 33% RPS target, and thus reduce long-term costs of the RPS Program.

7.8. Bid Selection Protocol

Since it believes it is well positioned to meet its RPS targets under both a 33% RPS target and a 40% RPS scenario, PG&E proposes that it not issue a 2015 RPS solicitation. PG&E will continue to procure RPS-eligible resources in 2016 through other Commission-mandated programs, such as the ReMAT and RAM Programs. We accept this request for 2015. PG&E is required to first seek the Commission's permission before entering into any bilateral contracts during the time period covered by PG&E's 2015 RPS Procurement Plan. In addition, should PG&E determine that an RPS solicitation is needed during the time period covered by the 2015 solicitation cycle, PG&E is required to first seek the Commission's permission.

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48 *Id*. at 50.

49 *Id*. at 51.

7.9. Price Adjustment Mechanism

PG&E states it will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule.[50] Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.

7.10. Economic Curtailment

PG&E states it made a presentation on economic curtailment to its Procurement Review Group (PRG) in May 2015. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally and for PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in 2015 has generally increased in the Real-Time Markets, even during the low hydro conditions of 2015. During January through May 2015, negative price intervals in the CAISO Five Minute Market for the North of Path 15 Hub occurred more than 1,800 times (4.2% of 5 minute intervals) compared to 1,100 times (2.5%) during the same period in 2014. Similarly, the ZP26 Hub prices for this period in 2015 were negative over 4,100 times (9.5%), a substantial increase over the 2014 results of 1,400 times (3.3%). Increased

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[50] *Id*. at 53.

negative price periods have led to increased curtailments of renewable resources that are economically bid. The specific occurrences of negative price periods and over generation events are largely unpredictable.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3. of PG&E's 2015 RPS Plan.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

7.11. Expiring Contracts

Appendix E to PG&E's 2015 RPS Plan lists the projects under contract to PG&E that are expected to expire in the next 10 years. The table includes the following data:

1. PG&E Log Number
2. Project Name
3. Facility Name
4. Contract Expiration Year
5. Contract Capacity (MW)
6. Expected Annual Generation gWh
7. Contract Type
8. Resource Type

9. City
10. State
11. Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA

7.12. Cost Quantification

Tables 1 through 4 in Appendix D to PG&E's 2015 RPS Plan provide an annual summary of PG&E's actual and forecasted RPS costs. Page 1 of Appendix D outlines the methodology for calculating the costs and generation. Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-2014) and forecast (2015-2030).

7.13. Imperial Valley

PG&E quotes from its May 7, 2015 Advice Letter 4632-E regarding Imperial Valley (IV):

Overall, the response of developers to propose IV projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the IV or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[51]

PG&E believes that given the level of the response from IV projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the IV as a part of the RPS Plan.[52]

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[51] *Id*. at 61.

[52] *Id*.

7.14. Important Changes to Plans Noted

PG&E identified and summarized the key changes and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan:

Reference	Area of Change	Summary of Change	Justification
Section 1	Section format and structure	Remove "Executive Summary" from Introduction.	Ease of document flow.
Entire RPS Plan	Consideration of a Higher RPS Requirement	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	Assigned Commissioner's Ruling (ACR) at pp.5-6.
Section 2.1	Commission Implementation of SB 2 (1x)	Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X).	ACR at p. 4.
Section 3.2.2	Impact of Green Tariff Shared Renewable Program	Include discussion of impact of Green Tariff Shared Renewable Program on RPS position.	D.14-11-042; D.15-01-051.
Section 3.4	Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations	Include discussion of IC adder as part of LCBF bid evaluation methodology.	ACR at p.15.

Reference	Area of Change	Summary of Change	Justification
Section 3.5	RPS Portfolio Diversity	Include discussion of efforts to increase portfolio diversity.	ACR at p.10.
Section 5.4	Curtailment of RPS Generating Resources	Include discussion of economic curtailment as a potential compliance delay.	ACR at p.16.
Section 11	Economic Curtailment	Include discussion of economic curtailment.	ACR at p.16.
Appendix C.1b	RNS Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix C.2b	Alternate RNS Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.2b	Project Failure Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.

Reference	Area of Change	Summary of Change	Justification
Appendix F.3b	RPS Generation Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.4b	RPS Deliveries Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.5b	RPS Target Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.

7.15. Redlined Copy

A complete redline of the draft 2015 RPS Plan against PG&E's 2014 RPS Plan is included as Appendix A to PG&E's draft 2015 RPS Plan.

7.16. Safety Considerations

Because PG&E claims its role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), it has divided this discussion into two situations.

7.16.1. Development and Operation of PG&E-Owned RPS-Eligible Generation

To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E states that it follows its internal standard protocols and practices to ensure public, workplace, and contractor safety.[53] For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[54]

PG&E states that it operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration and the California Public Utilities Commission's General Order (GO) 167.[55] PG&E claims it does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.[56]

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance.

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[53] *Id*. at 64.

[54] *Id*.

[55] *Id*. at 65.

[56] *Id*.

Environmental consultants are assigned to each of the generating facilities and support the facility staff.[57]

With regard to employee safety, PG&E states that Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.[58]

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident (MVI) Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and re certification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training

[57] *Id.*

[58] *Id.*

- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness[59]

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of its personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E is developing and implementing a public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.[60]

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards,

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59 *Id*. at 66.

60 *Id*. at 67.

inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.[61]

7.16.2. Development and Operation of Third-Party Owned, RPS-Eligible Generation

PG&E claims that the majority of its procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E intends to add additional contract provisions to its contract forms to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

7.17. Conclusion RE PG&E's 2015 RPS Plan

We find that PG&E's 2015 RPS Plan satisfies the specific requirements for the 2015 RPS procurement plans that were set forth in the Assigned Commissioner's Revised Ruling dated May 28, 2015.

In addition, we find PG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2015 solicitation to be reasonable. Should PG&E determine that an RPS solicitation or bilateral contracts are

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[61] *Id.*

needed during the time period covered by the 2015 solicitation cycle, PG&E is directed to first seek the Commission's permission in a manner consistent with the Commission's Rule of Practice and Procedure. The authorization granted in this decision solely exempts PG&E from the annual solicitation requirement for 2015.

8. SDG&E

8.1. Summary

SDG&E states it's RPS Plan establishes guidelines for SDG&E's procurement of LCBF RPS-eligible resources that will enable SDG&E to achieve the following levels of renewable deliveries during each CP: (a) an average of 20% of retail sales between January 1, 2011 and December 31, 2013, inclusive (CP1); (b) 25% of retail sales by December 31, 2016, with reasonable progress made in 2014 and 2015 (CP2); (c) 33% of retail sales by December 31, 2020, with reasonable progress made in 2017, 2018 and 2019 (CP3); and (d) 33% of retail sales in each year beyond 2020[62] (Post-2020 CP).

SDG&E also states that it expects to meet its CP2 goals with RPS eligible procurement already under contract, and that it will refrain from soliciting new renewable resources in the 2015 procurement cycle.[63]

8.2. Assessment of RPS Portfolio Supplies and Demand

SDG&E states it makes procurement decisions based on how its risk-adjusted RPS position forecast (referred to herein as its "RPS position")

[62] Compliance towards Post-2020 Compliance Period goals shall be measured in accordance with D.11-12-020, OP 4.

[63] SDG&E's 2015 RPS Plan at 14.

compares to its RPS program compliance requirements, the result of which is its probability-weighted procurement need or Renewable Net Short (RNS).[64] In order to calculate its RPS Position, SDG&E assigns a probability of success, following a qualitative and quantitative assessment, to the expected deliveries for each project in its portfolio and then adds the risk-adjusted expected deliveries across all projects in its entire RPS portfolio.[65] SDG&E uses probabilities because renewable projects and their deliveries are exposed to multiple risks, and the flexible compliance mechanisms that allowed for borrowing from future procurement were eliminated by SB 2 (1X).[66] These risks include approval risks (*e.g.*, Commission approval and the timing of such), development risks (*e.g.*, permitting, financing, or transmission interconnection), delivery risks (*e.g.*, generation fluctuations given the variant-intermittent nature of some renewable resources, or operational challenges), and/or other risks (*e.g.*, under-development of transmission infrastructure common to a group of projects).

8.2.1. Assessment of Probability of Success

SDG&E states it must assess the probability of success of the following main types of projects: (a) delivering; (b) approved but not yet delivering; and (c) not yet approved.[67] SDG&E evaluates the probability of success for each project in its portfolio on a monthly basis in order to calculate its RNS, which is the basis for its procurement need. To do this, SDG&E conducts a monthly

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[64] *Id.* at 2.

[65] *Id.*

[66] Stats. 2011, Ch. 1.

[67] SDG&E 2015 RPS Plan at 3.

review with an interdisciplinary team and uses up-to-date qualitative and quantitative information to assign a probability of success to each individual project. SDG&E's most up-to-date assessment as of June, 2015 is set forth in Appendix 2 to its 2015 RPS Plan. The process consists of an assessment of performance of delivering projects; an assessment of the development progress of approved projects that have not yet begun delivering; and assessing of the approval queue for projects that have been submitted to the Commission but are not yet approved.[68]

8.2.2. Assessment of Other Portfolio Impacts

Once SDG&E has determined the probability of success for each of the contracts in its portfolio, SDG&E states it also considers a broader range of risk factors that can impact multiple projects or its entire portfolio. These risk factors include the impact of retail sales fluctuations; the impact of solar panel degradation; impact of key transmission upgrades and/or infrastructure; impact of contract renewal; impact of contract termination; impact of banking rules; impact of the resale market; impact of the Rim Rock Settlement; the impact of mandated procurement programs (such as the GTSR, the Bioenergy Market Adjusting Tariff [Bio-MAT], the Renewable market Adjusting Tariff [Re-MAT], and the Renewable Auction Mechanism [RAM]); the impact of local capacity resource needs; the impact of distributed generation policy goals; the impact of energy storage procurement; the impact of California Energy

[68] *Id*. at 3-4.

Commission requirements; and the impact of new generator interconnection and deliverability allocation procedure.[69]

8.2.3. Determination of the Compliance Needs for Each Compliance Period

After probabilities are assigned to each project, SDG&E's RNS is calculated by multiplying the forward contractual delivery profiles (including degradation) of each project by each project's probability weighting and then adding those generation profiles across the portfolio.

8.2.4. CP1 Procurement Needs

The compliance reporting process for CP1 is not yet complete. SDG&E will know the final first results of its CP1 RPS compliance efforts and any impact to its procurement needs once the CEC and Commission have completed their respective review processes.

8.2.5. CP2 Procurement Needs

Based on current projections, SDG&E expects that it will meet its CP2 RPS goals with generation from contracts that have been executed, together with the deliveries from UOG initiatives where relevant progress has been made.[70] SDG&E intends to manage potential over-procurement by banking it for future compliance needs, terminating contracts where conditions precedent are not met or where mutual agreement is reached, and/or selling such excess procurement.[71]

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[69] *Id*. at 5-13.

[70] *Id*. at 15.

[71] *Id*.

8.2.6. CP3 Procurement Needs

Based on SDG&E's current probability-weighted RPS position forecast, SDG&E states it is possible that SDG&E will not require additional procurement in CP3.[72] SDG&E stresses that this outlook is based on current data, and procurement needs are difficult to forecast for periods beyond several years into the future. The level of any new purchases required for CP3 will be a function of portfolio performance and will be subject to the level of banking, if any, related to potential excess procurement in CP2 into CP3. SDG&E intends to fill any remaining RPS need with viable low-cost opportunities from future solicitations, bilateral transactions, and potential investments, and will continue to procure from mandated programs to the extent required. SDG&E intends to manage potential over-procurement by banking it for future compliance needs, terminating contracts where conditions precedent are not met or where mutual agreement is reached, and/or selling such excess procurement.[73]

8.2.7. Post-2020 CP Needs

SDG&E may undertake procurement for this period of time to ensure compliance subsequent to the end of CP3, with the understanding that any resulting excess can be either banked or sold bilaterally or through an RFO.[74]

8.2.8. Utility Tax Equity Investment and Utility Ownership Opportunities

SDG&E believes that its participation as a tax equity investor in renewable generation projects enhances project viability (through securing of

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[72] *Id.*

[73] *Id.*

[74] *Id.*

financing) and decreases costs for ratepayers (given SDG&E's cost of capital relative to the renewable financing market).[75] Tax equity investments by utilities and other non-traditional investors are, in SDG&E's estimation, important in light of the phase out of the American Recovery and Reinvestment Act of 2009's creation of federal cash grant.[76]

SDG&E believes that it continues to make progress on its Solar Energy Project,[77] SDG&E expects construction of the 7.2 MW in projects to begin in late 2015 or early 2016, depending on permitting success. Anticipated deliveries from these projects, expected to begin in Q2 2016, have been incorporated into SDG&E's RPS procurement need forecast.[78]

8.2.9. System Requirements

Per SDG&E, a wide variety of procurement programs exists both within the RPS program, as well as in addition to the RPS program that will contribute to SDG&E's overall portfolio diversity.[79] SDG&E believes that another factor that will influence its portfolio diversity as well as help to appropriately address integration and over generation is the LCBF calculation that SDG&E will use to select shortlisted projects.[80] The methodology outlined in Appendix 9 to SDG&E's 2015 RPS Plan includes the newly adopted integration adder, the application of which will ensure that integration is factored into bid evaluation,

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[75] *Id.*

[76] *Id.*

[77] Approved by D.08-07-017.

[78] SDG&E's 2015 RPS Plan at 16.

[79] *Id.*

[80] *Id.*, and Appendix 9 attached thereto.

with the objective of selecting a diverse portfolio in consideration of system needs.

8.2.10. Portfolio Optimization Strategy

8.2.10.1. RNS Optimization

SDG&E proposes to calculate its forecasted RPS position, which will then be compared to its RPS compliance requirements to determine its RNS.[81]

SDG&E will use this RNS to determine the appropriate level of procurement, including the necessary margin of over-procurement, going forward. Generally, if SDG&E foresees a shortfall then it will procure additional resources; if it foresees an excess then it will seek to sell a portion or all of this excess pending the results of a detailed cost and benefit analysis of banking versus selling. Once SDG&E has determined its need, it proceeds to manage its procurement by continually reviewing its portfolio to minimize costs, maximize value and manage risk.

8.2.10.2. Cost Optimization

Once a contract is executed, if an opportunity to optimize the contract becomes apparent, SDG&E will investigate to determine the best course of action for ratepayers. SDG&E states that it analyzes bids and bilateral proposals according to its LCBF methodology.[82] The formula deducts the PPA Price (Levelized Contract Cost), Transmission Cost, and Congestion Cost from the sum of the Energy Benefit and Capacity Benefits to determine a project's NMV. These NMVs can then be compared and used to create a quantitative ranking. SDG&E then evaluates any identifiable qualitative aspects, such as

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[81] *Id*. at 17.

[82] *Id*. at 19.

DBE status, project viability, developer experience, and portfolio fit to determine the shortlist. Second, SDG&E utilizes Time-of-Day (TOD) factors and periods to provide a comparison between bids that are based on the best information available at the time of bid evaluation.[83] Third, SDG&E states it monitors existing contracts in an effort to optimize their performance on behalf of customers.[84] Fourth, SDG&E performs a banking versus sales analysis when it has excess RPS procurement in its portfolio.[85] This analysis is linked to its retirement analysis where SDG&E evaluates its compliance position and strategy to ensure that RECs are handled in the most cost-effective way for SDG&E's ratepayers. SDG&E considers the time value of the rate impact to bundled customers when making the decision to buy, sell, bank, or delay the retirement of RECs.

8.2.10.3. Value Optimization

SDG&E states that in addition to its contract analysis and management strategies, it also seeks to add value to the RPS procurement process by actively participating in the discussion of current and proposed procurement programs (such as the RAM Program and the Bio-MAT Program), and by evaluating procurement opportunities.[86] SDG&E also evaluates tax equity opportunities as a procurement option and assess the value of its involvement. SDG&E will enter into bilateral transactions if they benefit ratepayers.

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[83] *Id*. at 20.

[84] *Id*.

[85] *Id*. at 21.

[86] *Id*. at 22.

8.2.10.4. Risk Optimization

SDG&E addresses risk optimization through several long-term and short-term strategies to mitigate this risk, and also seeks to add value by participating in discussions regarding compliance and enforcement rules.[87] For example, with Category 1 Procurement, SDG&E faces a risk that its categorization of the contracts in its portfolio will not be accepted by the Commission. This risk will be alleviated to a degree after Category 1 Procurement compliance has been determined. A second long-term procurement strategy utilized by SDG&E is the adoption of a "buffer" or VMOP to ensure that SDG&E is able to reach its RPS goals. Third, there may be instances where SDG&E needs to procure a small amount of renewable energy in the near term. SDG&E sees short-term contracting as a viable strategy.[88]

8.2.11. Lessons Learned & Trends

8.2.11.1. Overbilling

As described in SDG&E's 2013 and 2014 RPS Plans, SDG&E states it is concerned that developers have provided profiles in prior solicitations that ultimately do not match the profiles of the facilities that are built,[89] in other words, developers have "overbuilt" facilities (i.e., installed capacity above the amount bid).[90] The resulting over generation has increased costs to customers through increased contract costs, and increased generation overall which increases the incidence of and payments for negative real-time energy pricing.

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[87] *Id.* at 23.

[88] *Id.* at 24.

[89] SDG&E 2013 RPS Plan, p. 37. SDG&E 2014 RPS Plan, p. 25.

[90] SDG&E's 2015 RPS Plan at 25.

In response to this observation, SDG&E modified its PPA to include a maximum limit on generation during each TOD period, which the Commission approved as a part of SDG&E's 2013 RPS Plan.

8.2.11.2. Pricing Transparency & Load Misalignment

SDG&E proposed flat TOD pricing in its 2014 RPS Plan. SDG&E originally proposed this change in an effort to prevent overbuilding, and upon further consideration has determined that overbuilding is more effectively addressed via stronger generation caps. However, SDG&E continues to believe that variable TODs should be removed from the contract for several reasons. First, SDG&E states that TODs are thought to incentivize a certain production profile, but in reality, an intermittent resource (such as solar or wind) can only produce when its fuel source is available. In practice, SDG&E asserts that variable TODs only serve to obscure the actual price of these resources as the actual price is a factor of the pre-TOD price, the annual generation, and the TOD factors in effect at the time of generation – a complicated calculation, the result of which cannot be gleaned from reading the contract.[91] Second, even if a renewable facility has dispatch ability (baseload for example) and can shift its production to some extent to match the TOD profile, the TOD periods and factors are reflective only of the load profile at the time of solicitation issuance and bid analysis but upon contract execution remain fixed for the contract term which could exceed 20 years.[92] As SDG&E's load profile moves (as it has and will continue to do), over time the contract could eventually provide for price multipliers that do not align with SDG&E's load profile, sending the wrong

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[91] SDG&E's 2015 RPS Plan at 28.

[92] *Id.*

price signals and possibly resulting in production that does not align with load which could lead to negative pricing events as explained in Section X of its 2015 RPS Plan. A solution could be to update contractual TOD factors and periods each year: however, SDG&E is concerned that this type of contractual provision may not be financeable.[93] TOD periods and factors are useful in project valuation as they assist in comparing the profiles of various technologies against one another using the best information available at the time, but these periods and factors should not be memorialized in a contract – they only obscure the true contract price, and could potentially encourage additional generation when it is not needed in the future, neither of which are beneficial to ratepayers.[94]

8.2.11.3. Peak Shifting

SDG&E asserts that as a result of the success of the RPS program, a significant amount of solar and wind energy has been added to the grid and there is much more planned to come online before 2020.[95] These renewable resources are very low variable cost resources that (at high penetration levels) will cause significant reductions in marginal prices in periods when they operate. Substantial amounts of rooftop solar are also being added by customers behind the meter. A large amount of variable resource penetration during any single time during the day may result in significant decreases in marginal energy prices and even significant ramping events. As a result of increased renewable generation in Southern California, the peak load net of

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[93] *Id*. at 29.

[94] *Id*.

[95] *Id*.

variable energy resources has shifted and will continue to shift as the California resource portfolio evolves. As market conditions develop it is important that SDG&E's TOD factors and time periods, which will be used for analysis purposes, reflect the most up-to-date information to provide ratepayers with the greatest value.[96]

8.2.11.4. Capacity Value

SDG&E's 2013 RPS Plan incorporated a new method for calculating capacity value by using an updated benchmark.[97] The new method uses an updated benchmark where energy values are based on a forecast of SP-15 energy prices and capacity values are based on the following:

- For Local Area Projects: the Marginal Generation Capacity Cost of $120/kW-year, which is intended to provide a proxy for the net cost of new entry, as discussed in Section 3 of the Revised Prepared Direct Testimony of David T. Barker, Chapter 5, On Behalf of SDG&E in connection with Application 11-10-002 (Application of SDG&E For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design).
- For Imperial Valley Area Projects: the expected cost of $70.88/kW-year[98] that the CAISO would charge SDG&E pursuant to its Capacity Procurement Mechanism (CPM) if SDG&E failed to meet local RA requirements (ICPM Order, 125 FERC ¶ 61,053 at P 15).
- For System Area Projects: the CPUC penalty of $40/kW-year[99] associated with failure to meet system RA requirements.

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[96] *Id*. at 30.

[97] SDG&E 2013 RPS Plan at 38.

[98] CAISO Fifth Replacement Electronic Tariff, Section 43.7.1 at 964.

[99] CPUC 2014 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings, p. 27.

SDG&E's updated benchmark values are reasonable because, when evaluating a contract on a standalone basis, it should be measured against the avoided costs the utility might face had this contract not been part of the portfolio. For example, if SDG&E had a resource in its portfolio, and that resource was crucial to meeting local resource adequacy requirements, the marginal value of that resource is the amount that SDG&E must pay if that resource becomes unavailable (the CAISO CPM rate) plus the cost to replace the energy that resource would have generated in order to serve hourly retail load. SDG&E sought to rely on rates that have been published and vetted by key stakeholders, and will update its calculations as the assumption sources are updated.[100]

8.2.11.5. Distributed Generation Deliverability

The CAISO conducts an annual assessment methodology for determining and allocating RA deliverability to DG resources at locations that do not require any yet-to-be-approved network transmission upgrades.[101] The assessment is coordinated with the CAISO's interconnection procedures and the CAISO's transmission planning process. The initiative is in support of California's goal of 12,000 MWs of DG by 2020.[102] SDG&E plans to monitor this annual assessment and will make existing and potential distribution-level resources aware of the need to apply for a potential assignment of deliverability.

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[100] SDG&E's 2015 RPS Plan at 30-31.

[101] *Id*.

[102] *Id*. at 31.

8.2.11.6. Delay of Commercial Operation Date (COD)

SDG&E states it is concerned that a facility could reach commercial operation prior to the contractual COD, but delay declaring COD until the COD date in the contract.[103] As a result, the facility would be paid for this energy at the contract price, thereby extending the term of its contract, resulting in an additional cost to ratepayers. To mitigate this issue, SDG&E has adjusted its PPAs, attached as Appendices 6, 7, and 11.A to its RPS Procurement Plan to change the price paid for energy delivered prior to COD to a fixed REC value plus CAISO revenues net of CAISO costs.[104]

8.2.12. Trends

8.2.12.1. Steady Project Success Rates

SDG&E has observed a positive trend in the success rate of achieving commercial operations of the projects in its current RPS portfolio, and has seen the rates hold steady at an average of approximately 90% for the past two years.[105]

8.2.12.2. Expansion of RA Products

SDG&E has observed an increasing interest in the RA program and the products it encompasses.[106] The RA program is currently the subject of Commission rulemaking proceedings R.14-10-010 Phase 1 and R.14-02-001. For the 2015 RA compliance year, Rulemaking 11-10-023 Phase 3 officially adopted the flexible RA requirement for 2015. The flexible RA requirement is intended

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[103] *Id*. at 32.

[104] *Id*.

[105] *Id*. at 33.

[106] *Id*.

to assist with increased energy ramping needs driven by the integration of growing levels of renewable energy onto the grid combined with the retirement of Once-Through Cooling (OTC) units. Since this is the first RA compliance year with mandatory flexible RA requirements for LSEs, the impact that flexible RA capacity will have on the market value of system and local RA is unknown at this time.

8.2.12.3. Multiple RPS Contract Versions Across Programs

SDG&E has noted that as the volume of mandated programs has increased, so have the number of contract versions that must be managed. At this time there are four distinct PPAs for RPS products, all with separate approval processes: the Long-Term and Short-Term RPS PPAs (attached as Appendices 6 and 7 to SDG&E's RPS Procurement Plan), the RAM PPA (attached as Appendix 11.A to SDG&E's RPS Procurement Plan), and the Re-MAT PPA.[107] Going forward, in accordance with D.14-11-042, SDG&E intends to use the TOD factors approved in each RPS Plan in all PPAs for RPS products executed in that plan year, with updates where appropriate.

8.3. Project Development Status

SDG&E has contracts with 8 projects that are in the pre-construction phase, 3 projects that are either under construction or are existing projects and 48 projects that are in commercial operation.[108]

SDG&E maintains that renewable project developers continue to face a challenging environment. Most recently, SDG&E observed many smaller

[107] *Id*. at 34.

[108] *Id*. at 34-35.

projects are experiencing local agency permitting delays as individuals and community groups challenge projects.[109]

8.4. Potential Compliance Delays

8.4.1. Transmission and Permitting

8.4.1.1. Interconnection Facility Delays

The timely approval, permitting, and completion of interconnection facilities are crucial to the successful implementation of SDG&E's renewable portfolio. With the completion of the ECO Substation, the DREW Switchyard and the interconnection of five renewable projects to the IV Substation, the key transmission facilities that can still impact SDG&E's renewable portfolio are the two new collector switchyards north of the IV Substation.[110] If development of these facilities is delayed or blocked, the ability to implement SDG&E's renewable portfolio may be adversely impacted.[111]

Existing transmission constraints between IV and the San Diego load center have been largely resolved with the construction of the Sunrise Powerlink project. However, ongoing requests to interconnect generation – principally new generation – in the San Diego and IV areas,[112] the anticipated retirement of coastal gas-fired power plants using ocean water for cooling, and the permanent retirement of the San Onofre Nuclear Generating Station (SONGS) has lead the CAISO to approve a new 230 kV Sycamore Canyon-Penasquitos transmission line. This new line will support the ability of

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[109] *Id*.

[110] *Id*. at 36.

[111] *Id*.

[112] 2012-2013 ISO Transmission Plan at 34.

renewable resources to obtain Full Capacity Deliverability Status (FCDS); thereby enhancing the likelihood that new renewable resources can be counted towards LSEs' RA requirements.[113]

8.4.1.2. Jurisdictional Agency Permitting Delays

Uncertainty surrounding the timely issuance of key permits associated with lead agency review continues to create risks for projects under development. The permitting timeline can vary greatly based on a multitude of factors including project location, environmental issues, lead/other agency resources, and public participation.[114] First, this uncertainty may lead to scheduling challenges and corresponding problems with project elements such as site control, financing, permitting, engineering, procurement including supplier and construction (EPC) contracts. Second, costs to mitigate environmental issues or respond to public concerns can lead to higher than expected costs for developers to complete a project.

8.4.2. Project Finance, Tax Equity Financing, and Government Incentives

Obtaining financing is key to the successful development of renewable projects. Two areas of financing are of primary importance: (i) project financing relied upon to construct the project; and (ii) tax equity financing relied upon to monetize tax benefits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC).[115] Financial institutions traditionally provide project financing, the cost and availability of which is a function of the overall

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[113] SDG&E's 2015 RPS Plan at 37.

[114] *Id*. at 39.

[115] *Id*. at 40.

health of the financial system. Tax equity financing is also traditionally provided by banks or large corporations. In order to secure financing, renewable projects generally must: (i) complete permitting; (ii) have a long-term fixed price PPA from a credit-worthy off-taker; and (iii) have a bankable (or proven) technology.

8.4.3. Debt Equivalence and Accounting

As SDG&E executes an increasing number of PPAs, the cumulative debt equivalence of all these agreements may affect SDG&E's credit profile and, consequently, its financial standing. Rating agencies include long-term fixed financial obligations, such as PPAs, in their credit risk analysis.[116] These obligations are treated as additional debt during their financial ratio assessment. Standard and Poor's views the following three ratios, Funds From Operations (FFO) to Debt, FFO to Interest Expense, and Debt to Capitalization, as the critical components of a utility's credit profile. Debt equivalence negatively impacts all three ratios. Unless this risk is mitigated, a PPA would negatively impact SDG&E's credit profile by degrading credit ratios.

In addition, the Accounting Standards Codification (ASC) 810 Consolidation, which includes the subject of Consolidation of Variable Interest Entities (VIEs). Application of ASC 810 as it pertains to Consolidation of VIEs could also impact SDG&E's ability to sign new contracts.[117] As part of SDG&E's overall internal review and approval process for new PPAs, SDG&E conducts a review of whether each PPA will be subject to consolidation under ASC 810. Under ASC 810, no renewable PPA has been deemed subject to such

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[116] *Id*.

[117] *Id*. at 41.

consolidation, however, ASC 810 requires SDG&E to perform an assessment for those contracts which are considered VIEs. For this reason, SDG&E believes that it is required to assess quarterly each contract or category of contracts to ensure continued compliance with ASC 810, to determine whether or not SDG&E must consolidate a seller's financial information with SDG&E's own quarterly financial reports to the Securities and Exchange Commission. The accounting rules associated with ASC 810 can change and thus wind, solar, geothermal and bio-gas renewable sellers could be impacted.

8.4.4. Regulatory Factors Affecting Procurement

The Commission is in the process of implementing changes to the RPS program required by SB 2 (1X) and SB 350. As a result, full program details are not yet final, which creates regulatory uncertainty.[118]

In addition, SDG&E believes the results of the CEC and Commission review and verification of SDG&E's CP 1 procurement and associated documentation will provide greater certainty regarding the PCCs of contracts in SDG&E's portfolio and will thereby inform SDG&E's procurement activities going forward.[119]

8.4.5. Unanticipated Curtailment

The incidence of curtailment has increased and will continue to do so as more and more intermittent renewable generation is brought online.[120] Curtailment is a factor of energy supply and demand which is in a constant state of flux, and although SDG&E does not have a robust set of data to analyze

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[118] *Id*. at 41-42.

[119] *Id*. at 42.

[120] *Id*. at 43, referencing Section X of SDG&E's 2015 RPS Plan.

curtailment and its impacts at this juncture, analysis will likely be possible in the future.

8.5. Risk Assessment

SDG&E periodically evaluates the risk that delivering projects will underperform. In SDG&E's experience, developers are inherently motivated to achieve the COD for their facilities and maintain successful operations due to several factors: (i) the significant investment required to achieve COD; (ii) the timely payments made for energy delivered once COD is reached; and (iii) the penalties incurred if the project does not meet contractual requirements to supply at least the minimum amount of energy contemplated. SDG&E anticipates meeting its CP2 targets with procurement already under contract, and estimates a project success rate of approximately 90% for the contracts currently in effect.[121] These two factors have mitigated the risk to SDG&E's portfolio. However, risks are still present, and over the past decade, SDG&E has observed some dynamic factors that may affect power production from delivering projects:

- Resource availability, Lower than Expected Generation, and Variable Generation;
- Regulatory Changes;
- Economic Environment;
- Evolving Technology; and
- Issues with Third Party Mandatory Systems.[122]

121 *Id*. at 44.

122 *Id* at 45.

The above factors contribute to SDG&E's monthly project assessments of the likelihood of each project's success.[123]

8.6. Quantitative Information

SDG&E's quantitative analysis in contained in Appendix 2 to its 2015 RPS Plan.[124] SDG&E has identified that the RNS calculations do not take the 36 month shelf life of RECs into consideration when calculating the IOUs compliance position. SDG&E intends to monitor the vintage and remaining life of RECs in order to maximize their value to the portfolio by retiring them at the most opportune time.

8.7. Minimum Margin of Over Procurement

SDG&E's RPS Risk Adjusted Net Short Calculation, as shown in Appendix 2 to its 2015 RPS Plan, provides a "Minimum Margin of Procurement" that is intended to account for foreseeable project failures or delays. This calculation also includes an additional VMOP, which is intended to ensure that SDG&E achieves its RPS requirements despite unforeseeable risks. Since both the RPS targets and RPS deliveries fluctuate constantly, it is nearly impossible to meet RPS targets with the exact number of MWh required.[125] SDG&E's VMOP is designed to ensure that it achieves its RPS goals with a "buffer" to account for unforeseen changes to either the RPS targets or deliveries.[126] Because it is more difficult to predict retail sales and project performance in CP2 and CP3, SDG&E's VMOP is higher in those years.

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[123] *Id*. at 46.

[124] *Id*.

[125] *Id*. at 46.

[126] *Id*.

SDG&E's RNS calculation, including its VMOP, for each year is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement + Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

a. Bundled Retails Sales Forecast = the forecast developed in accordance with Section II(A)(ii)(a) of SDG&E's 2015 RPS Plan

b. RPS Procurement Quantity Requirement = the target for the relevant CP or year

c. Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for the relevant CP or year

d. Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section II(A)(i)(a) of SDG&E's 2015 RPS Plan

e. Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section II(A)(i)(b) of SDG&E's 2015 RPS Plan

f. Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under fully implemented CPUC mandated procurement programs (RAM and Re-MAT).[127]

8.8. Bid Solicitation Protocol, Including LCBF

Attached to SDG&E's 2015 RPS Plan as Appendices 6-11.C are SDG&E's proposed RPS Long and Short-Term Model PPAs, RPS REC Agreement, LCBF,

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[127] *Id*. at 47.

RPS Sale RFP, RPS Sales Model PPA, and documentation for a SunRate RAM solicitation.

8.9. Consideration of Price Adjustment Mechanisms

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

- <u>Price adjustment for delay in Guaranteed Commercial Operation Date (GCOD)</u>: A lower price for a late GCOD provides additional incentive for developers to come online pursuant to the contract.[128]
- <u>Capped transmission upgrade costs</u>: Placing a cap on the amount of transmission upgrade costs, which are ultimately borne by ratepayers, that a project can incur is an effective way to limit ratepayer exposure to such costs. The cap is set as a condition precedent to SDG&E's obligations under the PPA. If estimated costs exceed the cap, SDG&E has the right not to move forward with the PPA.[129]
- <u>Price adjustment for higher than expected transmission upgrade costs</u>: Another mechanism that SDG&E has incorporated into past contracts is a mechanism whereby the seller agrees to a price reduction to offset higher than anticipated transmission upgrade costs. Under this mechanism, the contract price would be reduced on a dollars per megawatt-hour basis commensurate with the cost of transmission upgrades above an agreed upon cap. The price adjustment mechanism would include an upper limit on transmission upgrade costs, above which SDG&E can terminate the contract.[130]

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[128] *Id*. at 48.

[129] *Id*.

[130] *Id*. at 48-49.

- Price adjustment for failure to achieve full capacity deliverability status: If a project is not deemed fully deliverable by CAISO at the time of COD, then the PPA price is reduced by either (1) a negotiated price reduction specific to the project; or (2) the application of "energy only" TOD factors in place of "FCDS" factors until such time as the project is deemed fully deliverable.[131]

8.10. Economic Curtailment

The issue of curtailment is a result of the operational characteristics of the facilities within the renewable market (both those procured pursuant to the RPS program, as well as customer-side facilities). These resources are typically intermittent, which results in generation profiles that do not necessarily sync with load.[132] SDG&E states it does not have a robust set of data with which to perform a detailed economic curtailment analysis at this time because (i) SDG&E does not have the right to curtail the majority of its facilities and the number of such facilities has evolved over time, and (ii) the CAISO's revisions have been in effect for a little over one year and economic curtailments have only recently begun.[133] However, SDG&E believes that economic curtailment analysis will be possible in the future as contracts are amended to include economic curtailment rights, the updated contracts (attached as Appendices 6, 7, and 11.A to SDG&E's 2015 RPS Plan) which includes economic curtailment rights is used in further contracting, and as the passage of time yields a more complete set of data. SDG&E anticipates that this data could, for example,

[131] *Id*. at 49.

[132] *Id*.

[133] *Id*. at 51.

potentially be used to forecast curtailment, inform how SDG&E bids energy into the CAISO, and/or enhance the LCBF calculation.

8.11. Expiring Contracts

Appendix 4 to SDG&E's 2015 RPS Plan lists the contracts in SDG&E's portfolio, as of June 2015, that will be expiring in the next 10 years.

8.12. Cost Quantification

Appendix 3 to SDG&E's 2015 RPS Plan lists tables that provide an annual summary of both actual and forecasted RPS procurement costs and generation, by technology type, as of June 2015.

8.13. Imperial Valley

While SDG&E did not hold a 2014 RPS RFO, its RPS portfolio currently contains 11 contracts in the Imperial Valley/IID territory, that when completed will provide an estimated 3,000 gWh per year.[134] As of June 2015, seven of these projects have reached commercial operations, and the generation from these projects is anticipated to be approximately 2,500 gWh per year. The remaining projects are in various stages of construction. Additionally, projects located within IV and either directly connected or dynamically transferred via pseudo-tie into SDG&E's service territory by the CAISO are eligible to participate in SDG&E's GTSR program.[135]

8.14. Important Changes to 2014 RPS Plan

Important changes made to SDG&E's 2014 RPS Plan are detailed in Appendix 5 to SDG&E's 2015 RPS Plan.

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[134] *Id*. at 54.

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

8.15. Safety Considerations

8.15.1. RPS PPA

SDG&E's current procurement programs and the safety-related contractual provisions included therein are set forth below:

- PPA Provisions—Utility Scale RFOs (Long-Term and Short-Term Contracts) and SunRate RAM: Sections 1.1; 3.1(f)(ii); 3.5(a); 3.5(b), 3.5(c); 3.6(a)(i); 3.7(a); and Exhibit F (Form of Quarterly Progress Report, Section 9.0).[136]
- PPA Provisions—Customer Renewable Energy and Water Agency Tariff for Eligible Renewables FiT Programs: Section 5.4; Appendix F, Item 32; and Appendix F, Item 41.[137]
- PPA Provisions—Re-MAT FiT Program and GTSR ECR Program: Sections 6.4; 6.5.2; and Appendix A ("Demonstrated Contract Capacity;" "Inverter Block Unity Capacity;" and "Prudent Electrical Practices").[138]
- PPA Provisions—Bio-MAT FiT Program—Sections 5.4; 5.5.2; 5.17; and Appendix A.[139]

8.15.2. Renewable UOG Projects

SDG&E requires all contractors working on UOG facilities to observe a myriad of safety requirements, safety inspections, and reporting protocols.[140]

8.16. Renewable Auction Mechanism

SDG&E anticipates meeting its CP2 need with projects it already has under contract. Consequently, SDG&E will use the RAM solicitation documentation, attached hereto as Appendices 11-11.C, on an as-needed basis

[136] *Id*. at 55-58.

[137] *Id*. at 58-60.

[138] *Id*. at 60-63.

[139] *Id*. at 63-65.

[140] *Id*. at 65-71.

to procure for its GTSR program,[141] as authorized by D.15-01-051.[142] SDG&E has attached SunRate RAM solicitation form documentation[143] to its 2015 RPS Plan as Appendices 11-11.C. The RAM documentation is intended for procurement of resources for the Green Tariff (or "GT", referred to herein as "SunRate") component of SDG&E's GTSR program. SDG&E reserves the right to file a motion later in 2015 to update its 2015 RPS Plan if it determines that a RAM RFO, for purposes other than GTSR procurement, is necessary.

8.17. Green Tariff Shared Renewables Program

SB 43, which requires participating utilities to file an application for a GTSR program allowing customers to buy some or all of their energy from local renewable projects via a GT or an Enhanced Community Renewables (ECR) option, became effective on January 1, 2014.

Based on the information SDG&E has at the time of this plan submittal, it expects to initiate GT procurement via RAM VI as described above under Section II of its 2015 RPS Plan, initiate procurement for ECR following the completion of Phase IV, and implement the program pursuant to the Commission's forthcoming resolution.

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[141] SDG&E will use the capacity procured via the RAM mechanism to satisfy its LCR requirement if the resources contracted with are eligible.

[142] D.15-01-051, OP5 at 180.

[143] SDG&E states it reserves the right to update the RFO, RFO requirements, and accompanying solicitation documents as needed to reflect changed circumstances including, but not limited to: change in RFO bid platform, interconnection map changes, an increase in the MIC allocation from the Imperial Valley Substation, or based on changes made to the SunRate program in Phase IV of the GTSR proceeding.

8.18. Consideration of 40% by 2024

Under an increased RPS scenario, SDG&E states that its methodologies and strategies as outlined above would remain valid. Now that SB 350 has become law, the higher RPS standards are no longer hypothetical scenarios. In complying with SB 350, we expect SDG&E to calculate the additional costs to customers and additional impacts to the grid as it develops its compliance plan for the higher RPS targets.

8.19. Conclusion RE SDG&E's 2015 RPS Plan

We find that SDG&E's 2015 RPS Plan satisfies the specific requirements for 2015 RPS Plans that were set forth in the ACR dated May 28, 2015.

In addition, we find SDG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2015 solicitation to be reasonable. Should SDG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2015 solicitation cycle, 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 2015.

9. SCE's 2015 RPS Plan

9.1. Summary

In its 2015 RPS Plan, SCE proposes to conduct a targeted 2015 RPS solicitation that meets SCE's need for renewable resources. Similar to SCE's 2014 solicitation process, SCE proposes a solicitation process that is intended to capitalize on the maturing renewables market and target the most viable proposals that fit SCE's portfolio need and provide the most value to customers. In particular, SCE will continue to require that projects have a

Phase II Interconnection Study (or an equivalent or more advanced interconnection status or exemption) and an "application deemed complete" (or equivalent) status within the applicable land use entitlement process in order to submit a proposal. SCE will also solicit Category 1, Category 2, and Category 3 REC products in order to minimize costs to its customers. Furthermore, SCE will only consider proposals from projects with initial delivery dates to SCE of December 1, 2020 or earlier.[144]

9.2. Consideration of a Higher RPS Goal

The ACR required the retail sellers to consider both the current 33% by 2020 RPS goal, and a 40% by 2024 RPS goal when addressing specific requirements for the 2015 RPS Procurement Plans, SCE's 2015 RPS Plan considers both of these different RPS goals throughout. Now that SB 350 has become law, SCE must consider the higher RPS targets.

9.3. Assessment of RPS Portfolio Supplies and Demand

9.3.1. SCE's Renewables Portfolio

For the first CP from 2011 through 2013, SCE served 20.7% of its retail sales from RPS-eligible resources.[145] In 2014, SCE served 23.4% of its retail sales from RPS-eligible resources. To date, SCE's RPS-eligible deliveries and executed renewable procurement contracts have resulted from SCE's RPS solicitations, SCE's Renewables Standard Contract program, the AB 1969 feed-in tariffs, RAM auctions, ReMAT, the utility-owned generation and independent power producer (IPP) portions of SCE's Solar Photovoltaic

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[144] SCE's 2015 RPS Plan at 3-4.

[145] *Id*. at 11.

Program (SPVP), QF contracts, utility-owned small hydro projects, and bilateral opportunities.

Between January 2014 and June 2015, SCE executed 21 RAM contracts for approximately 331 MW, 11 ReMAT contracts for approximately 23 MW, 39 SPVP IPP contracts for approximately 63 MW, and two QF standard offer contracts for approximately 18 MW.[146] During this period, SCE also executed eight contracts for approximately 1,556 MW from its 2013 RPS solicitation.[147]

SCE launched its 2014 RPS solicitation on December 8, 2014. SCE has executed nine contracts from its 2014 RPS solicitation totaling approximately 680 MW.[148] SCE expects to execute additional contracts from its 2014 solicitation.[149]

9.3.2. SCE's Forecast of Renewable Procurement Need

Appendices C.1 through C.4 of SCE's 2015 RPS Plan include SCE's forecast of its renewable procurement position and need – i.e., SCE's RNS – based on the RPS program's 33% by 2020 target.[150] As provided in the ACR, Appendices C.5 through C.8 include SCE's forecast of its RNS based on the 40% by 2024 target set forth in the ACR.[151] Both sets of forecasts include the RPS targets adopted by the Commission in D.11-12-020 for all years through 2020.

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[146] *Id*. at 12. SCE notes that of these, two of the RAM contracts totaling 38 MW, one of the ReMAT contracts totaling 0.5 MW, and four of the SPVP IPP contracts for 5 MW subsequently terminated. This information is up to date as of June 30, 2015.

[147] *Id*.

[148] *Id*.

[149] *Id*.

[150] *Id*. at 12-13.

[151] *Id*. at 13.

9.3.3. SCE's Plan for Achieving RPS Procurement Goals

Through its 2015-2016 RPS procurement activities, SCE intends to contract for renewable energy. SCE's 2015-2016 RPS procurement activities will take into account: (1) the renewable energy procured through SCE's prior RPS solicitations, including the 2014 RPS solicitation, and other procurement mechanisms, (2) probabilistic risk adjustment of expected generation from executed contracts with projects that are not yet online, and (3) future RPS solicitations and other procurement mechanisms that are expected to take place, including any increased renewable targets which are adopted between now and when SCE selects a 2015 RPS solicitation shortlist.[152]

SCE plans to launch a 2015 RPS solicitation for long-term Category 1, Category 2, and Category 3 REC products. SCE will only consider proposals from projects with initial delivery dates to SCE of December 1, 2020 or earlier.

SCE forecasts that it will meet its RPS targets primarily through long-term Category 1 products because they provide the most flexibility for SCE's customers. In addition to long-term Category 1 products, SCE will solicit long-term Category 2 and Category 3 REC products in the 2015 RPS solicitation in order to minimize costs to its customers and gain information on the market for each portfolio content category.[153]

While SCE does not currently intend to sell bundled renewable energy, unbundled RECs, or other renewable energy products in the 2015 RPS

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[152] *Id*. at 16.

[153] *Id*.

solicitation, SCE may conduct a future solicitation or negotiate bilaterally to sell such products to maximize value to its customers and optimize its portfolio.[154]

9.3.4. SCE's Portfolio Optimization Strategy

The objective of SCE's renewables portfolio optimization strategy is to minimize costs to its customers while ensuring that RPS goals are met or exceeded. The first step in SCE's portfolio optimization strategy is developing a forecast of SCE's renewable procurement position and need, i.e., SCE's RNS. This includes a calculation of SCE's net position and SCE's bank. SCE evaluates its renewable procurement need by assessing bundled retail sales, the performance and variability of existing generation, the likelihood new generation will achieve commercial operation, expected online dates, technology mix, expected curtailment, and the impact of pre-approved procurement programs, among other factors. Annual variability of existing resources can either increase or decrease SCE's need and bank from year-to-year.[155]

If SCE's renewable need assessment results in a short position, SCE will hold an RPS solicitation if other procurement programs and mechanisms will not fill that position. SCE uses its LCBF methodology to evaluate renewable procurement opportunities as further described in Section IX.B and Appendix I.1 of its RPS Plan. The primary quantitative metric used for evaluating bundled renewable energy is NMV. SCE also relies on a number of qualitative factors such as resource diversity and transmission area, among other factors, when evaluating proposals.

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[154] *Id*. at 19.

[155] *Id*.

If SCE's need assessment results in a long position or it would otherwise optimize SCE's renewables portfolio or maximize value to its customers, SCE may use sales of renewable energy products,[156] project deferrals, and solicitation deferrals (as it did by not holding a 2012 RPS solicitation) in order to move its renewable procurement back in line with its forecasted renewable procurement need. Additionally, SCE actively administers its renewable procurement contracts.[157]

When SCE considers whether to engage in sales of renewable energy products, SCE compares the NMV for the sales transaction against the NMV of proposals submitted to SCE in recent solicitations and other offers. If the NMV for long-term renewable procurement is lower than the NMV for the sales transaction, it would be more cost effective for SCE to maintain its existing RPS bank for future compliance periods.[158] Conversely, if the NMV from recent solicitations is higher than the NMV for the sales transaction, SCE has an opportunity to optimize its renewables portfolio and realize value for its customers by selling renewable energy products.

In addition to the NMV considerations discussed above, SCE evaluates various potential risks when determining its renewables portfolio optimization strategy, including the risk of not meeting its RPS targets. When SCE has a long position in the near and intermediate term, SCE evaluates whether a sale

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[156] SCE states it procures renewable energy in compliance with the preferred loading order and when it expects to have a renewable procurement need. SCE does not purchase RPS-eligible energy for the express purpose of selling it at a later date.

[157] SCE contends that contract amendments have the potential to decrease contract prices or provide other benefits to customers.

[158] SCE 2015 RPS Plan at 20.

of renewable energy products is appropriate. This evaluation includes a calculation of SCE's renewable procurement position and RPS bank with a set of adverse assumptions.[159]

Finally, SCE continues to analyze the effects of procurement of RPS-eligible resources on other procurement programs in order to consider portfolio impacts. The Commission and the CAISO debated flexibility requirements in the Resource Adequacy ("RA") proceeding to help manage the intermittency created on the grid by certain renewable resources. A portfolio-wide optimization strategy will need to assess the composition of SCE's renewables portfolio, as resources such as geothermal and other baseload resources may potentially reduce flexibility requirements.[160]

9.3.5. SCE's Management of its Renewable Portfolio

After SCE executes an RPS PPA, the PPA is managed by the Energy Contracts Contract Management group.[161] Many projects require some form of PPA modification to attain commercial operation. Modifications include, but are not limited to, specific provisions to aid the seller in reducing the overall costs of the project, ability to true-up milestones and timelines outlined in the PPA as interconnection and permitting information is updated, and other miscellaneous changes to allow the project to move forward. Generally, projects require very few PPA modifications after attaining commercial operation.

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[159] *Id*. at 21.

[160] *Id*. at 20-21.

[161] *Id*. at 22.

In evaluating modifications or amendments to a PPA, SCE applies guidance from D.88-10-032. Although D.88-10-032 was enacted as a set of guidelines for the administration of QF contracts, SCE has been using it when administering all forms of PPAs. At a high level, D.88-10-032 gave the IOUs the option to determine whether to enter into an amendment with any counterparty.[162] In the event an amendment is elected, the IOU should negotiate in good faith.[163] D.88-10-032 also provides that in response to requests for contract modifications, an IOU is to seek concessions that are commensurate with the change being sought.[164] The details of D.88-10-032 provide further guidance to the IOUs to restrict modifications to PPAs with viable projects,[165] and reject modifications that would result in creating an essentially new project.[166]

9.3.6. Lessons Learned, Past and Future Trends, and Additional Policy/Procurement Issues

9.3.6.1. Lessons Learned and Past and Future Trends

SCE asserts that it continues to refine both its RPS solicitation process and its *pro forma* PPA as a result of lessons learned from SCE's extensive experience in contracting for renewable resources. Over the course of the last several years, SCE has also incorporated or accounted for several trends in its

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162 *See* D.88-10-032 at 16.

163 *See id.* at Conclusion of Law 8.

164 *See id.* at 16, Conclusion of Law 13-14.

165 *See id.* at 17, Conclusion of Law 4, Appendix A at 4-5.

166 *See id.* at 26, Conclusion of Law 17.

renewable procurement planning and solicitation process.[167] The lessons learned are identified as follows:

9.3.6.1.1. Elimination of Pre-Paid Economic Curtailment Bidding

In the 2014 RPS solicitation, SCE required sellers to submit two prices per proposal based on SCE discretionary curtailment orders:

- Price 1: Sellers offer pricing based on SCE having the right to issue unpaid Curtailment Orders[168] for a quantity of curtailed energy equal to 50 hours times the contract capacity in each term year (the "curtailment cap"). Any Curtailment Order resulting in curtailed energy in excess of the curtailment cap would be paid at the contract price.
- Price 2: Sellers offer pricing based on SCE having to pay the contract price for all Curtailment Orders.

While SCE did select some Price 1 option proposals in its 2014 RPS solicitation, the data SCE received on Price 1-type projects indicates that pre-payment for economic curtailment may not provide the best value to SCE's customers.[169] Given the uncertain value pre-payment of economic curtailment represents, SCE proposes to not require sellers to bid the pre-paid economic curtailment option with the curtailment cap in the 2015 RPS solicitation.[170]

9.3.6.1.2. Valuation of Transmission Costs for Projects Located Within and Outside the CAISO Control Area

In past RPS solicitations, SCE included the full reimbursable transmission network upgrade costs in the quantitative valuation process for projects

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167 SCE's 2015 RPS Plan at 23.

168 Curtailment Order was defined in Section 3.12(g)(iii) of SCE's 2014 *Pro Forma* Renewable Power Purchase and Sale Agreement.

169 SCE's 2015 RPS Plan at 24.

170 *Id*. at 25.

directly connected to the CAISO control area. Additionally, SCE included reimbursable transmission network upgrade costs outside the CAISO as a qualitative factor in the LCBF evaluation process for projects not directly connected to the CAISO control area, but where California customers will pay for the costs. SCE took the approach of evaluating the total cost of new build renewable projects from a societal perspective, thereby factoring in 100% of the reimbursable transmission network upgrade costs for any new project located within California or directly connected to the CAISO control area via a CAISO interconnection study. However, other utilities in California have not been factoring in costs from the perspective of all California customers; instead, they have only been valuing reimbursable transmission network upgrade costs relative to their own customers. SCE believes that this could put its customers at a disadvantage because other utilities may be executing renewable contracts for lower contract prices than SCE because the reimbursable transmission network upgrade costs that are not paid by those utilities' customers were not considered in the valuation of the contracts, while SCE was considering costs not paid by its customers in its valuation.[171]

Therefore, for the 2015 RPS solicitation, SCE proposes to consider reimbursable transmission network upgrade costs for projects directly interconnecting to the CAISO control area in the LCBF evaluation process.[172] In addition, SCE will only consider the share of the reimbursable transmission network upgrade costs that are paid by SCE customers.[173]

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[171] *Id*. at 25-26.

[172] *Id*. at 26.

[173] *Id*.

9.3.6.1.3. Limiting Sellers to Eight Proposals Per Project

Historically, SCE states it has not limited the amount of proposals sellers could bid for the same project. As a result, sellers could submit an unlimited amount of proposals in multiple ways.[174] In the 2015 RPS solicitation, SCE will limit the number of proposals submitted on a "per project" basis to eight.

SCE contends that limiting sellers to eight proposals from the same project provides sellers with adequate opportunity to submit proposals with variables that are specific to those projects and will provide SCE a robust pool of projects and proposals to select. The eight proposals will provide sellers the opportunity to meet the minimum bid requirement of a 10-year term, start dates in each of the term years, different contract capacity bids (project sizes), or other seller-specific pricing variation.[175] At the same time, limiting the proposals to eight per project will decrease complexity for both sellers and SCE during the verification and valuation process.[176]

9.3.6.2. Additional Policy/Procurement Impacts

SCE identifies two prior Commission decisions that it contends will impact its procurement:

- On February 13, 2013, the Commission issued D.13-02-015, the LTPP Track 1 decision, which authorized SCE to procure between 1,400 and 1,800 MW of electrical capacity in the Western Los Angeles sub-area of the Los Angeles basin local reliability area ("Western LA Basin sub-area") and 215 to 290 MW of electrical capacity in the Moorpark sub-area of the Big Creek/Ventura local reliability area to meet local capacity

[174] *Id*. at 26.

[175] *Id* at 27.

[176] *Id*.

requirements (LCR) by 2021 due to the expected retirement of once-through cooling units. D.13-02-015 required SCE to procure minimum amounts of gas-fired generation, Preferred Resources (including renewable resources), and energy storage in the Western LA Basin sub-area.[177]

- On March 13, 2014, the Commission issued D.14-03-004, the LTPP Track 4 decision, which authorized SCE to procure an additional 500 to 700 MW of capacity in the Western LA Basin sub-area due to the retirement of the San Onofre Nuclear Generating Station. Combined, D.13-02-015 and D.14-03-004 authorized SCE to procure between 1,900 and 2,500 MW of capacity in the Western LA Basin sub-area. The LTPP Track 4 decision did not address or change the authorized procurement for the Moorpark sub-area.[178]

Consistent with these decisions, SCE's 2015 Procurement Protocol solicits projects in the Western LA Basin sub-area to participate in the 2015 RPS solicitation.[179] Additionally, projects located in the Western LA Basin sub-area that are interconnected to SCE's distribution system served by Johanna and Santiago substations may also meet SCE's Preferred Resources Pilot (PRP) goal.[180] To the extent SCE receives proposals for projects in these areas that are not selected in SCE's RPS solicitation based on LCBF selection criteria, SCE will consider the value of these proposals using the LCR selection process and criteria.

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[177] *Id*.

[178] *Id*. at 27-28.

[179] *Id*. at 28.

[180] *Id*.

9.4. Project Development Status Update

Appendix B to SCE's 2015 RPS Plan contains a status update on the development of RPS-eligible projects currently under contract, but not yet delivering generation.

9.5. Potential Compliance Delays

SCE identifies five primary facts that it claims will challenge achievement of the State's RPS goals: (1) curtailment; (2) the increasing proportion of intermittent resources in SCE's renewables portfolio; (3) permitting, siting, approval, and construction of both renewable generation projects and transmission; (4) a heavily subscribed interconnection queue; and (5) developer performance issues.[181] SCE discusses each of these factors is discussed in detail in its 2015 RPS Plan.[182]

9.6. Risk Assessment

In forecasting its renewable procurement position and need, SCE accounts for potential issues that could delay RPS compliance, project development status, minimum margin of procurement, and other potential risks through the use of probabilistic risk-adjusted success rates for energy deliveries from contracts that are executed but not yet online.[183] SCE considers these risk factors in this process. Additionally, SCE takes into account historic generation from existing resources, including lower than expected generation, variable generation, and resource availability, among other factors, when

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[181] *Id*. at 29.

[182] *Id*. at 30-36.

[183] *Id*. at 36.

forecasting expected generation from its contracted renewable projects.[184] The quantitative analysis of these considerations is provided in Appendices C.1 through C.8 of SCE's 2015 RPS Plan.

9.7. Quantitative Information

Appendices C.1 through C.4 of SCE's 2015 RPS Plan include SCE's RNS calculations using the standardized reporting template included in the RNS Ruling under the current 33% RPS program rules. As required by the ACR, SCE has also included RNS calculations under the 40% target set forth in the ACR in Appendices C.5 through C.8 of SCE's 2015 RPS Plan. As required by the Commission's Revised RNS Methodology, Appendices C.1, C.2, C.5, and C.6 of SCE's 2015 RPS Plan include physical RNS calculations and Appendices C.3, C.4, C.7, and C.8 of SCE's 2015 RPS Plan include optimized RNS calculations.

At this time, SCE does not propose including a VMOP in its renewable procurement planning. SCE will account for additional forecasting risks through the use of forecast RECs above its RPS procurement quantity requirements.

9.8. Minimum Margin of Procurement

SCE's renewable procurement efforts will be guided by its forecast of its renewable procurement needs. SCE contends that the Commission should rely on retail sellers to calculate their minimum margins of procurement and should not attempt to impose a one-size-fits-all approach. As many of the projects in SCE's portfolio become operational, SCE will face different risks, including

[184] *Id.*

integration of these resources.[185] The risks associated with project failure will be replaced by less significant risks of projects generating below full capacity. Similarly, SCE expects that the portfolio risk picture is not the same for each retail seller. For example, risks may vary depending on whether a portfolio contains a high proportion of contracts that are online (as discussed above) or depending on the various technologies being used (e.g., geothermal technology, which is a baseload resource, versus wind or solar technologies, which are more intermittent as described in Section V.B of SCE's RPS Procurement Plan).[186]

9.9. Bid Solicitation Protocol, Including LCBF Methodologies

9.9.1. Bid Solicitation Protocol

SCE includes its proposed 2015 Procurement Protocol as Appendix F.1 to its 2015 RPS Plan. The Procurement Protocol includes, among other things:

- SCE's requirements for initial delivery dates and preferred contract term lengths;
- Deliverability characteristics and locational preferences;
- SCE's requirements for LCR and PRP projects;
- Encouragement for Women-Owned, Minority-Owned, Disabled Veteran-Owned, Lesbian-Owned, Gay-Owned, Bisexual-Owned, and/or Transgender-Owned Business Enterprises ("Diverse Business Enterprises") to participate in SCE's RPS solicitation and information on how sellers can help SCE to achieve GO 156 goals;
- Requirements for each proposal submission;

[185] SCE's 2015 RPS Plan at 47.

[186] *Id*. at 47-48.

- A description of the type of products SCE is soliciting;
- A schedule of key dates related to the 2015 RPS solicitation;
- SCE's 2015 *Pro Forma* Renewable PPA ("*Pro Forma*"), attached as Appendix G.1;
- SCE's 2015 *Pro Forma* Master Renewable Energy Credit Purchase Agreement ("REC *Pro Forma*"), attached as Appendix H; and

SCE includes a discussion of the important changes in the proposed 2015 solicitation documents from SCE's 2014 solicitation documents in Section XV of its 2015 RPS Plan.

9.9.2. LCBF Methodology

SCE performs a quantitative assessment of each proposal and subsequently ranks them based on each proposal's benefit and cost relationship.[187] The result of the quantitative analysis is a rank order of all complete and conforming proposals' net levelized cost that help define the preliminary shortlist. Following the quantitative analysis, SCE will conduct an assessment of the top proposals' qualitative attributes.[188] These qualitative attributes, including factors such as local reliability, resource diversity, and nominal contract payments, are considered to either eliminate or add projects to the final shortlist based on qualitative attributes, or to determine tie-breakers, if any. Once a project is added to the shortlist, SCE may enter into a PPA with the project.[189]

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[187] *Id*. at 49.

[188] *Id*.

[189] *Id*.

9.10. Price Adjustment Mechanisms

SCE does not plan to solicit price structures based on indices in its 2015 RPS solicitation. Sellers can still bid escalation factors in their prices.[190]

9.11. Economic Curtailment

In its 2014 RPS solicitation, SCE required sellers to submit proposals both with and without a curtailment cap. SCE proposes to not require sellers to bid the economic curtailment option with the curtailment cap in the 2015 RPS solicitation.[191] SCE will retain the right to curtail at its discretion, but will pay for curtailments directly resulting from SCE marketing decisions. As in prior years, SCE will not pay for curtailments in response to an emergency, or due to CAISO or transmission provider instructions.[192]

9.12. Expiring Contracts

For SCE's RPS-eligible contracts expiring in the next ten years, Appendix E to its 2015 RPS Plan includes the name of the facility, technology, contract expiration date, nameplate capacity, expected annual generation, location, contract type, and portfolio content category classification.

9.13. Cost Quantification

The spreadsheet attached as Appendix D to SCE's 2015 RPS Plan includes actual expenditures per year for RPS-eligible generation for every year from 2003 through 2014, as well as actual RPS-eligible generation for every year from 2003 through 2014. Appendix D also includes a forecast of future

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[190] *Id*. at 49.

[191] *Id*. at 51.

[192] *Id*. at 51-52.

expenditures SCE may incur every year from 2015 through 2030, as well as a forecast of expected generation for every year from 2015 through 2030.

9.14. Imperial Valley

SCE states that in addition to the ORNI 18 project, which has been online and operating since October 2009, SCE executed PPAs with two projects (Mount Signal) located in the IID in the 2013 RPS solicitation.[193] Both of those solar projects have executed interconnection agreements, are fully permitted. In SCE's 2014 RPS solicitation, SCE received 382 unique complete and conforming proposals.[194]

9.15. Important Changes from 2014 RPS Plan

SCE's 2015 RPS Plan proposes several important changes to: (1) SCE's 2015 Procurement Protocol; (2) SCE's 2015 *Pro Forma*; and (3) SCE's LCBF Methodology.

9.15.1. 2015 Procurement Protocol

First, SCE intends to include long-term Category 2 products in its 2015 solicitation to provide additional flexibility and contracting opportunities for its customers.[195] Any contracts for Category 2 products ultimately executed by SCE will be within the limits on procurement of Category 2 products.

Second, SCE is requiring sellers to provide a minimum of one proposal out of the eight allowable proposals per project as a 10-year delivery term.[196]

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[193] *Id*. at 52.

[194] *Id*.

[195] *Id*. at 53.

[196] *Id*. at 54.

Third, SCE will not require sellers to bid the pre-paid economic curtailment option with the curtailment cap in the 2015 RPS solicitation.[197]

Fourth, for the 2015 RPS solicitation, SCE will eliminate sellers' option to bid price adjustment mechanisms.[198]

Fifth, SCE intends to provide sellers with further direction on the products and the timeframes where SCE has a need. SCE wants to focus the efforts of both SCE and sellers on proposals that are likely to be most valuable to SCE's customers.[199] To this end, SCE intends to solicit offers with delivery terms commencing on or before December 1, 2020.[200]

Sixth, SCE's 2015 RPS solicitation will include a Standard Contract Option based on the RAM procurement tool authorized in D.14-11-042.[201]

Seventh, SCE will limit sellers to eight proposals per project in the 2015 RPS solicitation.[202]

Eighth, SCE will not entertain mutually inclusive offers going forward.[203]

Ninth, SCE will begin to transition RPS solicitation sellers to an evergreen Non-Disclosure Agreement (NDA) process, which is currently used in other procurement solicitations (All-Source RFOs, LCR RFO, etc.).[204]

Tenth, SCE is eliminating the Seller's Form of Proposal attachment.[205]

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[197] *Id*.

[198] *Id*. at 55.

[199] *Id*.

[200] *Id*.

[201] *Id*. at 56.

[202] *Id*.

[203] *Id*.

[204] *Id*.

Eleventh, SCE plans to combine all of the required attestations into one form that an officer of seller's company must sign.[206]

Twelfth, SCE will eliminate the requirement that all projects selected for the shortlist post a shortlist deposit because SCE does not believe it has added value to the solicitation process.[207]

Thirteenth, SCE proposes to add a requirement that sellers execute an exclusivity agreement with respect to shortlisted projects.[208]

Fourteenth, in order to promote supplier diversity, SCE has incorporated Lesbian-Owned, Gay-Owned, Bisexual-Owned, and/or Transgender-Owned Business Enterprises into its definition of Diverse Business Enterprises consistent with D.15-06-007.[209] SCE has also included, as an attachment to its 2015 Procurement Protocol, a sample list of potential products and services that may be available through Diverse Business Enterprise subcontractors.[210]

9.15.2. Important Changes in SCE's 2015 *Pro Forma*

9.15.2.1. Pre-Paid Economic Curtailment: Sections 3.12(g) and 4.01(b)(iii)

SCE is eliminating the requirement that sellers bid the pre-paid economic curtailment option with the curtailment cap in the 2015 RPS solicitation.[211] SCE

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[205] *Id*.

[206] *Id*.

[207] *Id*.

[208] *Id*. at 58.

[209] *Id*. at 59.

[210] *Id*.

[211] *Id*. at 60.

is also eliminating the provisions regarding pre-paid curtailment hours and the curtailment cap in the 2015 *Pro Forma.*

9.15.2.2. Elimination of Startup Period and Initial Synchronization Period: Section 4.01 and Exhibit E

SCE will eliminate the startup period and initial synchronization periods that are outlined in the PPA.[212] SCE believes that the elimination of these provisions will simplify contract administration and project onboarding for future projects.[213] SCE also believes that this change will also provide for cost certainty for SCE customers.[214]

9.15.2.3. Financial Consolidation: Section 8.06

SCE is also incorporating language into the 2015 *Pro Forma* that will obligate sellers to provide SCE with appropriate financial statements in order to include projects in its financial filings to the Securities and Exchange Commission in the event that SCE must consolidate any entity in which it has a controlling financial interest.[215]

9.15.2.4. No Return of Development Security for Failure to Obtain Permits: Section 3.06

SCE will be entitled to retain 100% of the seller's development security in the event a project is unable to achieve commercial operation due to its inability to obtain material permits for the project.[216]

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[212] *Id*.

[213] *Id*.

[214] *Id*.

[215] *Id*.

[216] *Id*. at 62.

9.15.2.5. Development Security Due at PPA Execution: Section 3.06

SCE has moved the posting of the full development security to PPA execution.[217] This is a departure from the prior practice of requiring sellers to post the first half of their collateral within 30 calendar days of the PPA's execution, and the second half within 30 calendar days after final Commission approval.[218]

9.15.2.6. Tax Credit Legislation: Section 1.05 and Former Sections 1.04(b), 1.10 and 2.03(a)(ii)

To the extent sellers are able to take advantage of any new tax incentives not contemplated at the time of PPA execution, SCE proposes a discount to the contract price related to any unforeseen tax benefits that would be triggered if applicable tax laws were to be extended or enacted.[219] The amount of the discount will be an agreement between the parties, including those sellers who of 2015 *Pro Forma* elect the Standard Contract Option.[220] SCE has updated its 2015 *Pro Forma* to include language that implements this discount mechanism.

9.15.2.7. Levelized Performance Assurance: Section 1.06

SCE will require performance assurance to be posted in a single amount over the delivery term of the PPA (levelized), as opposed to bell-curve shaped amounts (shaped) as it has in the recent past.[221]

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[217] *Id*. at 63.

[218] *Id*.

[219] *Id*. at 65.

[220] *Id*.

[221] *Id*. at 66.

9.15.2.8. TOD Factors: Exhibit I of 2015 *Pro Forma*

SCE has updated the TOD factors in its 2015 *Pro Forma* to reflect the changes to its forecast of load, resources, and additions and retirements.[222]

9.15.2.9. Confidentiality Provisions: Section 10.10 and Former Exhibit

SCE has revised the confidentiality provisions in the 2015 *Pro Forma* to eliminate Exhibit I, which was a stand-alone NDA applicable to the PPA.[223] Instead, SCE will incorporate the material requirements from Exhibit I into the relevant confidentiality provisions in Section 10.10, as is done in all other SCE *pro forma* PPAs.[224]

9.15.2.10. Illustrating Contract Capacity in both Alternating Current (AC) and Direct Current for Solar Photovoltaic Projects: Section 1.01(h)

According to SCE, as there are no specific AC nameplate capacity restrictions within the 2015 Procurement Protocol or program rules, SCE believes it is reasonable to allow developers to install more AC capacity than they plan to deliver in order to account for reactive power requirements and losses, provided they utilize plant controllers to limit their AC output to their allotted interconnection capacity at the point of delivery.[225] Therefore, SCE is modifying Section 1.01(h) in the 2015 *Pro Forma* to require sellers to provide both the maximum output at the delivery point and the AC nameplate capacity of the generating facility.

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222 *Id*.

223 *Id*. at 67.

224 *Id*.

225 *Id*.

9.15.2.11. Supplier Diversity: Section 3.17(i)

SCE states that the 2014 *Pro Forma* already included a requirement to report payments made to Women-Owned, Minority-Owned, and Disabled Veteran-Owned Business Enterprises that supplied goods or services as subcontractors under a contract with SCE.[226] The 2015 *Pro Forma* will include all Diverse Business Enterprises in that reporting requirement.[227]

9.15.3. Important Changes in LCBF Methodology

9.15.3.1. Valuation of Transmission Costs for Projects Located Within and Outside the CAISO Control Area

SCE will only consider reimbursable transmission network upgrade costs that are paid by SCE customers in the LCBF evaluation process for the 2015 RPS solicitation.[228] For projects connecting to the CAISO control area, this will be the share of costs that SCE's customers pay for reimbursable transmission network upgrade costs. For projects not connecting to the CAISO control area, it will be zero as none of those costs are paid by SCE's customers. For most of the projects connecting to the CAISO control area, the costs that SCE customers pay is determined based on a utility-specific Transmission Access Charge rate, which is based on a utility's load share. The CAISO publishes these rates every year. SCE will use the latest rates available for SCE at the time of 2015 RPS solicitation evaluation process.[229]

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[226] *Id*. at 68.

[227] *Id*.

[228] *Id*.

[229] *Id*.

9.15.3.2. Selection of Projects Based on Qualitative Criteria

In the shortlist for the 2014 RPS solicitation, SCE selected resources according to the LCBF principles.[230] When procuring resources for the long-term, SCE uses the LCBF methodology to ensure the portfolio increases the confidence level of meeting SCE's RPS goals.[231] In the 2015 RPS solicitation, SCE will continue to use this approach and will continue to refine the approach based on changes to SCE's portfolio and updated RNS and load forecasts.[232]

9.15.3.3. SCE Experience with Developers as a Qualitative Factor for Shortlisting and Selection

In 2015 RPS solicitation, SCE will add prior experience with renewable developers as a qualitative factor for consideration for both shortlisting and final selection purposes.[233]

9.16. Safety Considerations

SCE's 2015 *Pro Forma* provides that the seller must operate the generating facility in accordance with "Prudent Electrical Practices."[234] The detailed definition of "Prudent Electrical Practices" includes "those practices, methods and acts that would be implemented and followed by prudent operators of electric energy generating facilities in the Western United States, similar to the Generating Facility, during the relevant time period, which practices, methods and acts, in the exercise of prudent and responsible professional judgment in the light of the facts known or that should reasonably have been known at the

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230 *Id*.

231 *Id*.

232 *Id*. at 69.

233 *Id*.

234 *See* 2015 *Pro Forma* (attached as Appendix G.1 to SCE's 2015 RPS Plan) at Section 3.12(a).

time the decision was made, could reasonably have been expected to accomplish the desired result consistent with good business practices, reliability and safety. . . ."[235]

SCE's 2015 *Pro Forma* also provides that, prior to commencement of any construction activities on the project site, the seller must provide to SCE a report from an independent engineer certifying that seller has a written plan for the safe construction and operation of the generating facility in accordance with Prudent Electrical Practices.[236]

SCE also has a safety section in its 2015 Procurement Protocol providing that sellers must possess a written plan for the safe construction and operation of the generating facility as set forth in the 2015 *Pro Forma*.[237]

9.17. Standard Contract Option

In its 2015 RPS solicitation, SCE plans to include a "Standard Contract Option" using the RAM procurement tool. Consistent with the Commission's intent expressed in D.14-11-042 to provide the IOUs with flexibility to optimize their portfolios based on their procurement needs while providing a streamlined procurement tool,[238] the Standard Contract Option will allow for rapid development of renewable projects by avoiding the contract negotiation process and expediting the Commission approval process of executed PPAs. Sellers will have the option to participate in the Standard Contract Option by checking a box in the RPS proposal form. The Standard Contract Option will

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235 *See id.* at Exhibit A.

236 *See id.* at Section 3.11(e).

237 *See* 2015 Procurement Protocol (attached as Appendix F.1) at Section 9.03.

238 *See id;* and D.14-11-042 at 91-92, and 102-104.

only be available for proposals offering Category 1 products, and will not be available for proposals offering Category 2 or Category 3 unbundled REC products, where contract negotiations are likely to be required. Additionally, the Standard Contract Option will only be available to projects with a first point of interconnection to the CAISO, and not to dynamically scheduled projects. SCE also discusses the parameters of the Standard Contract Option with respect to procurement need, standard contract, project size restrictions, project characterizations, restriction on subdivided projects, locational restrictions, valuation and selection, interconnection studies, commercial operation deadline, and the Commission approval process.[239]

9.18. GTSR Program

In accordance with D.15-01-051 and Advice 3195-E, SCE is seeking to procure 50 MW of Green Rate-eligible resources through the RAM 6 auction in order to meet its advanced procurement need.[240] On an annual basis, SCE plans to assess its Green Rate procurement need in each RPS Procurement Plan and set Green Rate procurement targets for each solicitation, if any, based on incremental customer enrollments and the amount of dedicated Green Rate procurement it already has under contract.[241] If a Green Rate procurement need is identified, SCE plans to procure Green Rate-eligible resources through the Standard Contract Option portion of the RPS solicitation. SCE will provide Green Rate-eligible resources the option to select consideration for the Green

[239] SCE 2015 RPS Plan at 72-78.

[240] *Id*. at 80.

[241] *Id*.

Rate program, in addition to consideration for the RPS program, as part of the solicitation.[242]

9.19. Conclusion re SCE's RPS Plan

We find that SCE's 2015 RPS Plan satisfies the specific requirements for 2015 RPS Plans that were set forth in the ACR dated May 28, 2015.

10. Remaining RPS Plans

In reviewing the RPS Plans submitted by Liberty Utilities LLC and Bear Valley Electric Service, we find that their respective Plans satisfy the information requirements 6.1 through 6.6, 6.8, and 6.13 through 6.15 set forth in the ACR. Additionally, we generally find the Integrated Resource Plan and On-Year Supplement filed by PacifiCorp to be consistent with Commission requirements and with the ACR. Therefore this decision also accepts the Integrated Resource Plan and On-Year Supplement filed by PacifiCorp. The remaining RPS Plans were submitted by ESPs. We find that their respective Plans satisfy the information requirements 6.1 through 6.6, 6.13 and 6.15 set forth in the ACR.

11. Summary of Comments, Reply Comments, and Conclusions

11.1. RPS Requirements and SB 350

11.1.1. Should the Commission Adopt 40% Requirements for 2024?

Parties Opposed: PG&E and SDG&E

PG&E and SDG&E argue that the Commission should wait until Governor Brown acts on the pending legislation and then allow for a thorough

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[242] *Id.*

review of the legislation, and comments from the parties to address the implementation of a higher RPS requirement.

Parties in Support: CEERT, IEP, LSA, Jan Reid, and SCE

IEP: The Commission should direct the utilities to modify their RPS Procurement Plans to treat the 2024 40% target as minimum procurement levels from a planning and procurement perspective.

LSA: The Commission should adopt the proposed 40% RPS by 2024 goal and direct retail sellers to reevaluate their procurement needs. Parties should be afforded an opportunity to comment on updated plan.

CEERT: The Commission should expressly permit IOU RPS procurement above 33%.

Jan Reid: The Commission should increase the IOUs' RPS percentage requirement to 40% in 2024. 40% RPS requirement will result in costs of $1.9 billion and a minimum benefit of $2.04 billion for a benefit/cost ratio of 1.07.

SCE: The pending legislation would adopt procurement targets and new rules that impact the RPS program, including the use of short-term contracts. The Commission should adopt the changes to the RPS program established in SB 350 and not create confusion by adopting different rules.

Order: This decision will consider procurement proposals that will help meet their near-term RPS procurement. The Commission will address implementation of SB 350 in 2016 since the IOUs are in no immediate threat of not meeting their procurement targets of 40% in 2024.

11.1.2. Procurement Needs and Solicitations: PG&E claims it will not have an RPS need until 2022. SCE plans to hold an RPS solicitation in 2015. SDG&E states that it plans no RPS solicitation for several years given its current forecasted position.

Oppose: IEP

IEP: Commission should consider PG&E's conclusion that it has no current need for RPS procurement in light of the Governor's Executive Order B- 30-15. The 2020 33% RPS goal is a minimum target.

Support: PG&E, SDGE

PG&E: An RPS solicitation in 2015 is unnecessary because of the existing portfolio of executed RPS contracts, owned generation, and expected bank balances. PG&E will still have more than enough time to conduct solicitations in the future to meet any incremental need resulting from new RPS requirements.

SDG&E: SDGE will issue an all-source solicitation in 2016 which will include soliciting for renewable projects that can satisfy local capacity reliability needs.

Discussion

For 33% 2020, SCE plans to launch a 2015 RPS solicitation for long-term Category 1, Category 2, and Category 3 unbundled REC products. SCE will only consider proposals from projects with initial delivery dates to SCE of December 1, 2020 or earlier.

For 40% in 2024, PGE proposes minimum bank size of 11,000 gWh for 40%.

Order: This decision accepts SCE's proposal to procure resources in 2015.

Since PG&E and SDG&E do not intend to procure resources in 2015, they should not enter into bilateral contracts. We reject any current proposals for 2024 including PG&E's proposal for a bank size. Instead, these proposals should be considered in SB 350's implementation.

11.1.3. Inclusion of Avoided GHG Emissions

ORA argues that the IOUs should be required to include avoided GHG emissions (in metric tons) as a result of their procurement of renewable resources. ORA further recommends that Energy Division run workshops, with an opportunity to file post-workshop comments, so that the Commission can gain stakeholder input to finalize the scope of the GHG abatement cost to be included in the RPS Procurement Plan filings.

Order: The Commission will consider this issue as part of the SB 350 implementation.

11.2. PG&E's Plans

Jan Reid states the Commission should order PG&E not to sign index contracts for RPS resources. Mr. Reid is unaware of any PG&E RPS contract that has been indexed to the cost of solar panels or wind turbines. The vast majority of index contracts are based on commodity indices or on inflation rates.

PG&E opposes this request. PG&E's PPAs do not include these kinds of provisions. Rather than adopt blanket rules for index and escalation provisions the Commission should consider actual provisions in the context of specific transactions when determining whether index or escalation provisions are reasonable.

Order: The Commission agrees with PG&E. Since index contracting is part of a non-standard PPA, PG&E can present it for Commission approval if and when it enters into such a contract. Jan Reid does not provide a persuasive reason for rejecting index contracts.

With respect to PG&E's request to simplify its PPA's and include only a single set of TOD factors to be applied to both energy-only and fully deliverable resources, this decision agrees with PG&E's request. In addition, as stated in D.14-11-042, PG&E, SCE and SDG&E are authorized to file Tier 1 Advice Letters, as needed, to request the Commission to approve of conforming TOD factors across all their RPS procurement programs. These

Advice Letters shall be served on R.15-02-020, or then current RPS proceeding, and all entities in the RPS procurement program queues.

11.3. SDG&E's Plans

11.3.1. SDG&E's proposed flat TOD factor to 1

Opposed: IEP and LSA

IEP's immediate observation is that flattening the TOD pricing periods risks undercutting the value that renewable projects paired with storage may bring. Moreover, flattening the TOD pricing periods seemingly will undermine the Commission's efforts to obtain renewable resources that are truly Least-Cost/Best-Fit.

LSA contends that SDG&E's proposal on negative real-time Locational Marginal Price is problematic as it misallocates risk for potential negative pricing which is not only dependent on the output of a particular facility but the available transmission, scheduling and dispatch of the entire portfolio.

Order: This decision rejects SDG&E's request. While basing a payment structure on current TOD factors may not be optimal for aligning generation with actual need 20 years from now, TODs are not only a component of determining costs and payments, but as IEPs pointed out part of bid evaluation. Therefore, we decline SDG&E's request and defer consideration of the issue until the Commission considers LCBF reform, which is currently scoped in this proceeding.

11.3.2. Overbuilding should be Addressed Through Stronger Generation Caps

ORA supports IOU efforts to include contractual safeguards that prevent ratepayers from paying excessive and unwarranted generation costs.

IEP is opposed. The Commission has recognized the potential for over generation and has created a program in which the buyer and seller are positioned to negotiate acceptable curtailment rights to be exercised by the buyer. This policy should remain the foundation for addressing over generation matters, rather than authorizing SDG&E to receive the energy and associated RECs without compensation.

Order: This decision approves SDG&E's modification. In D.14-11-042 the Commission approved similar provisions for SCE based on the following reasons: 1) It is reasonable to expect that the seller will construct a facility consistent with the terms of the contract. 2) It is reasonable that the contracts have both lower and upper bounds for energy deliveries. 3) While deliveries may reasonably vary for weather or other issues, we find the terms reasonably accommodate such variations and that the proposed terms reasonably limit ratepayer exposure to excess costs due to excess deliveries of a particular contract and/or excess procurement from inaccurate RNS forecasts.

11.3.3. SDG&E will Pay a Facility Energy Delivered Prior to COD to a Fixed REC Value Plus CAISO Revenues Net of CAISO Costs

SDG&E is concerned that a facility could reach commercial operation prior to the contractual COD, but delay declaring COD until the COD date in the contract. As a result, the facility would be paid for this energy at the contract price, thereby extending the term of its contract, resulting in an additional cost to ratepayers. To mitigate this issue, SDG&E has adjusted its PPAs, to change the price paid for energy delivered prior to COD to a fixed REC value plus CAISO revenues net of CAISO costs.

IEP is opposed. It argues that this proposal risks undermining the phased development of projects, particularly large renewable projects in which blocks of capacity are developed and installed over a phased timeframe. Under these conditions, it is typical for a project to generate energy as the blocks of capacity get developed, and the contractual COD will not occur until all of the blocks are completed.

Order: This decision approves SDG&E's proposal. SDG&E's proposal to compensate developers for energy before COD at a market price is reasonable, but clarifies that the price of the REC will be established in the contract and reviewed for reasonableness at the time of Commission review and approval of the contract.

11.4. SCE Plans[243]

11.4.1. SCE Proposes to Impose on RPS Bidders an Obligation to Submit, for Each Project out of Eight Allowable Projects, at Least One Bid with a Contract Term of 10 Years.

Oppose: IEP

- The proposal, if adopted, would only serve to constrain the marketplace (e.g., eliminating otherwise competitive bidders unable to accept a 10-year term at any price).
- Imposing an obligation on the bidders to develop and propose at least one 10-year term contract is a misuse of bidders' time and resources.

Order: This decision denies SCE's request, in part. Imposing an obligation to submit a 10 year bid is not reasonable because it is possible that it may not be economically feasible to execute a PPA of that term length, thus constraining the market place. SCE should impose the requirement for a 10

[243] SCE submitted a number of proposals related to the RPS Program rules. We have not addressed them in this decision as they have been made moot by the enactment of SB 350.

year bid as a potential option for the bidders. SCE's proposal to limit bidders to eight bids per project is approved.

11.4.2. SCE's Proposes to Require Sellers to Execute an Exclusivity Agreement with Respect to Shortlisted Projects.

Oppose: IEP, CalWEA, LSA

- IEP: Given that the California RPS market is characterized by many sellers but relatively few buyers, requiring bidders to execute exclusivity agreements, results in an arbitrary and unnecessary restraint on competition.
- Almost by definition, not all shortlisted projects will be selected for a contract, and binding bidders to one buyer for a shortlisted project forecloses the project from the opportunity to enter into a contract with another entity.
- CalWEA: Reject SCE's proposal to require sellers to execute an exclusivity agreement with respect to shortlisted projects, with the exception of standard offer contracts. Commission rejected this requirement in D.13-11-024 and D.14-11-042. However, SCE's proposal that sellers who utilize the standard contract option (i.e., execution of SCE's 2015 pro forma with no further negotiations) should be subject to an exclusivity requirement would be reasonable if SCE commits to enter into a standard contract with the short-listed project.

Order: This decision denies SCE's request. In D.13-11-024 and D.14-11-042, we found that short list exclusivity was an unnecessary restriction on the market based on the current level of competition. There is no evidence that the standard contract option in the RPS program requires a change in this position.

11.4.3. SCE Proposes to Eliminate Any Obligation to Pay for Energy Produced During the Startup Period And Initial Synchronization.

Oppose: IEP

- IEP: Because the 33% RPS is a floor and not a ceiling, any energy received by SCE during the startup period and initial synchronization period helps SCE meet its RPS goals. SCE should not be entitled to receive this RPS-eligible energy including the REC without appropriate compensation.

Support: SCE

- The provision eliminates SCE's operational burdens associated with scheduling and settling power during the startup period.
- SCE's proposal clearly defines what party gets the benefit (i e., CAISO revenues) and has the responsibilities (i.e., CAISO costs) prior to COD, it will reduce the amount of potential disputes associated with the start-up and initial synchronization activities, and it will simplify SCE's contract management and operational and settlement administrative responsibilities.

Order: This decision grants SCE's proposal. SCE should have the option to buy or not buy energy from the seller prior to COD. IEP does not point out any difficulty the developer might face to sell this energy in the market.

11.4.4. SCE Proposes to Obligate Sellers to Provide SCE with Financial Statements in Order to Include Projects' Information in SCE's Financial Filings for the Securities and Exchange Commission in the Event that SCE Must Consolidate any Entity in Which it has a Controlling Interest.

Oppose: IEP

- IEP opposes SCE's proposal. SCE acknowledges that it has never been required to consolidate sellers under RPS contracts in its financial statements.
- To impose such a significant reporting requirement on the operator in response to a very low (almost nonexistent) risk that SCE *might* be subject to consolidation requirements at some uncertain future point is not justified.

Order: This decision grants SCE's request. The Commission approved a similar provision in PG&E's 2014 RPS PPA.

Therefore, it is reasonable for SCE to include a similar provision where it can request such documents should the need arise.

11.4.5. SCE Proposes to Retain 100% of the Development Security if a Project Misses its Commercial COD Due to an Inability to Obtain Material permits. SCE proposes to require sellers to post the full development security at contract execution.

Oppose: IEP, LSA

- IEP: As a practical matter, permitting progress is in many key respects beyond the control of the developer. The Commission spent an extensive amount of time integrating the concept of "project viability" into bid evaluation, and, as a result, the utilities currently employ a number of tools to identify and evaluate the risk of delayed permitting as part of bid evaluation, selection, and approval. Moreover, as a component of the Project Viability Calculator, the utilities specifically assess a project's "progress toward completion," including the consideration of permitting status and development progress. There is no evidence that imposing a higher security burden on Sellers will reduce, let alone eliminate, the risk of default that SCE believes this change will cure. Moreover, increasing the security obligation will simply increase the risk premium that is factored into bids.
- LSA: Requiring the entire security at contract execution is an additional burden on sellers and will result in a higher cost premium. The timing of the approval of the PPA is largely dependent on the actions of the contracting utility and Commission. As such, the seller should not have to haven additional costs related of potential delays that are out of its' control.

Order: This decision grants SCE's request. The Commission is working towards increasing project viability of the IOUs' RPS portfolios. (*See* May 21, 2014 ALJ Ruling). Forfeiting developmental security provides a disincentive to developers who have permitting issues from participating in the RPS program. The expected outcome is that developers should not propose projects on lands with significant project development risks.

11.4.6. SCE Plans to Eliminate the Option of SCE having the Right to Issue Unpaid Curtailment Orders to 50 hours Times the Contract Capacity in Each Term Year. Any Curtailment Order Resulting in Curtailed Energy in Excess of would be Paid at the Contract price.

Order: This decision grants SCE's request as it simplifies the contracting process.

11.4.7. SCE does not Plan to Solicit Price Structures Based on Indices in its 2015 RPS Solicitation.

Order: This decision grants SCE's request.

11.5. Least-Cost Best-Fit

11.5.1. CalWEA's Proposal: The commission should direct the utilities to use LCBF values that are consistent with the values used in the RPS calculator. The commission should direct SCE and SDG&E to use the ELCC methodology in calculating RA values.

CalWEA Rationale:

- The RPS Calculator will be used to generate renewable resource portfolios for purposes of studying needed planning transmission and system reliability resources, and would include expected over generation for the optimized base case RPS portfolio for the 2016 LTPP. If actual procurements are not aligned with this planning, at least for a basecase assessment, the Commission risks planning for a different resource mix than what actually materializes.
- Any significant deviations from this base case shortlist should be justified in terms of assuring that the differences will not cause inconsistencies with system planning efforts.

Oppose: LSA, SCE, SDGE, PG&E

- LSA: A careful assessment and testing of the current methodologies for LCBF and those in the RPS Calculator should be undertaken prior to attempting to use the Calculator or any of its elements for procurement evaluation. ELCC has not been vetted.
- SCE: The RPS Calculator uses its own net market value (NMV) methodology to value projects based on various criteria in order to establish policy-based renewable portfolios. This NMV methodology is designed for generation and transmission planning from a state-wide perspective. However, there are numerous site-specific and projector developer-specific considerations that apply to the valuation of actual RPS projects that cannot be satisfactorily replicated in a generic tool such as the RPS Calculator (*e.g.*, project deliverability based on point of interconnection, renewable integration impacts based on specific renewable resource characteristics, and developer collateral capability).
- SDGE: The Calculator is a Statewide, high-level planning tool that informs the LTPP and TPP. Changes should be made to the RPS Calculator to the extent it requires adjustment in order to accurately reflect renewable procurement practices; changes should not be made to renewable procurement practices in an effort to support assumptions made by the RPS Calculator.
- PG&E: The RPS Calculator was developed only for high-level planning purposes and does not contain sufficient granularity or complexity to reasonably inform project-specific, LCBF evaluation.

Order: This decision reject's CalWEA's request. As noted above, the scope of the proceeding includes examining reform measures regarding least-cost, best-fit. As such, this request is better suited for study as part of the LCBF reform.

11.5.2. CalWEA's Proposal: The commission should direct the utilities to develop optimum renewable energy portfolios for purposes of LCBF evaluation. The long-term impact of resources on the entire portfolio should be accounted for. (CalWEA p. 12)

CalWEA Rationale:

- o Project is evaluated on the basis of its net market value today, using market-value.
- o Projections that may not take into account larger RPS portfolios that are expected in the future.
- o Develop a base case portfolio that incorporates the longer-term projected RPS goals and then reflecting, in the NMV process, the expected impact of adding an RPS resource to that portfolio.
- o The substantial benefit of this approach is that resources would be evaluated based on the impact of the resource on the 33%, 40% or 50% portfolio, not just the market value of the marginal resource. Specifically, it would better capture the over generation impact of proposed resources down the road.

Oppose: LSA

- o LSA: This assessment is best suited for study in the context of long-term resource planning or through the forthcoming Integrated Resource Planning framework. These kinds of interrelated issues are likely difficult to capture in procurement evaluation and could lead to over-valuing or under-valuing a resource if evaluated without the context of other procurement choices (including those occurring outside the RPS), other improvements in practice and demand-side changes.

Order: This decision reject's CalWEA's request as it is better suited for study as part of the LCBF reform.

11.5.3. CalWEA's Proposal: The Commission should Ensure that there is no Double Counting of Costs between the

Integration Cost Adder in SCE's LCBF Methodology and other NMV Components (CalWEA 14)

CalWEA Rationale:

- The IC adder is being concurrently developed in the LTPP proceeding for use in the RPS LCBF evaluations
- In generating the IC adder, energy value and integration costs are both captured in total production cost savings, with integration costs "taking back" some of the energy value of renewables

Oppose: SCE

SCE's LCBF methodology does not lead to double counting of IC adders because integration adders are only used at the end of its LCBF bid valuation process, and not as an input to unit commitment and dispatch used to generate fundamental power prices. SCE applies the integration adder as a distinct cash flow component after the valuation modeling process. SCE uses the integration adder solely to differentiate value for different types of intermittent renewable contracts and not as a component of its energy value.

Order: This decision grants CalWEA's proposal. There is no evidence that the IOUs are double counting costs between the IC adder and NMV. But as a practice, the IOUs should include a description of how there is no double counting between the IC adder and NMV components in their LCBF methodology section of the RPS plan.

11.5.4. CEERT's Proposal: LCBF methodologies should reference GHG emission reduction considerations or metrics.

Order: This matter will be considered in 2016 as part of the SB 350 implementation and LCBF reform.

11.5.5. CalWEA's proposal: The Commission should direct the utilities to carefully consider energy value in the LCBF process consistent with the RPS Calculator.

CalWEA Rationale:

Because different types of renewable resources have significantly different generation profiles and thus produce significantly different energy values, the Commission should direct the utilities to ensure that their LCBF methodologies capture these differences in energy value in ways that are consistent with those produced by the RPS Calculator.

Clarification from SCE and SDGE

SCE: LCBF methodology already addresses this concern. SCE's fundamental price forecast is derived from a base portfolio and system that is consistent with SCE's most recent LTPP, which includes RPS assumptions based on the RPS calculator.

SDG&E notes that its LCBF evaluation already accounts for both saturation effects and energy value, thereby enabling SDG&E to make procurement decisions on a project-specific basis. The NMV analysis utilizes the current target of 33%, and should this target be raised in the future, the NMV calculation will be appropriately adjusted.

Order: This issue belongs in LCBF reform. CalWEA is correct to suggest that the utilities should ensure that their LCBF methodologies capture the differences in energy value for different types of renewable resources. However, it is premature to suggest that the utilities should replicate the method used in the RPS calculator.

11.5.6. IEP's Proposal: To the extent that storage can be paired with an RPS-eligible resource in a RPS bid and approved by the Commission, then that storage resource should count toward the utilities' storage procurement goals. RPS LCBF bid evaluation methodology must explicitly consider this combination, and bidders need to understand

generally how the added benefit of storage paired with a renewable resource will be valued by the utility.

PG&E offers the following clarification: its RPS procurement already provides opportunities to directly pair storage with eligible renewable resources, including in the last two RPS solicitations. Furthermore, the existing LCBF methodology is robust and already values the attributes of storage paired directly with renewable resources.

Order: As PG&E acknowledges that IEP's suggestion is already in practice, the matter need not be considered further at this time.

11.6. Permitting Shared Equipment

11.6.1. CalWEA's Proposal: The Commission should direct the utilities to revise their PPAs to permit projects with shared facilities, including shared transformers, and projects using low-side metering because the current restrictions are not required for CAISO compliance and will result in unnecessary costs.

Oppose: PG&E and SCE

PG&E proposes not to conduct a solicitation and thus did not include a *pro forma* PPA, but asserts that CalWEA's concerns are outside of the scope of this proceeding and should not be addressed in the abstract.

SCE states it has and will continue to allow the sharing of some facilities between projects. But SCE disagrees with CalWEA's recommendation that shared transformers and low-side metering should be permitted in either the Renewable Auction Mechanism or in other procurement programs.

Order: This decision grants CalWEA's request. Utilities should allow shared transformers. The use of shared facilities can reduce costs by allowing two small projects to share portions of the required interconnection infrastructure, thereby reducing costs. Shared facilities can also reduce environmental impacts by avoiding the need to route new gen-ties or expand existing substations to accommodate the interconnection of additional lines.

Section 10.2.10.1 of the CAISO tariff allows CAISO Metered Entities to install revenue quality meters on the low voltage side of step-up transformers if they have obtained the prior approval of the CAISO. CAISO Metered Entities that have installed low voltage side metering, whether such installation was before or after the CAISO Operations Date, shall apply the Transformer and Line Loss Correction Factor in accordance with Section 10.2.10.4.

Section C of the CAISO BPM for metering describes how to calculate the transformer and line loss correction factor.

SCE's argument regarding meter accuracy is not persuasive. SCE argues that dynamic factors would account more accurately account for losses attributable to the respective generation from each facility. Arguments around loss factors belong to the CAISO stakeholder process for "Metering and Telemetry." Currently, the CAISO allows low side metering with the application of transformer correction factor.

Utilities may include provisions that require developers to install high-side metering if CAISO enforces the requirement.

11.7. Cost Control

11.7.1. The Commission should establish caps on each utility's VMOP.

Support: ORA and Jan Reid

- ORA: Each IOU incorporates foreseen and unforeseen risk in its RNS position through qualitative assessments and weighted probabilities of success for delivering and developing projects. Considering the increasing direct and ("VMOP"), indirect costs of purchasing and integrating renewable energy, the Commission should consider outward boundaries to a utility's VMOP that adequately balances compliance.

- o Commission should balance such risk with ratepayer impact.

Oppose: PGE, SCE, SDGE, LSA

- o PG&E: Limiting the VMOP, may not be the most effective manner for achieving cost containment and may unduly restrict PG&E's procurement flexibility Incremental procurement is not only a function of the Bank size, but also the cost of RPS-eligible products in the short- and long-term. Commission should establish a PEL.
- o SCE: Many factors can impact the level of the bank in a retail seller's portfolio, including: the level and uncertainty of bundled sales, fuel source mix in the portfolio, performance of existing resources, project success rates, delay or acceleration of online dates, performance of new facilities once they are operational, level of existing portfolio that is re- contracted, and curtailment. Each of these factors may be large or small risks to each retail seller. It is impractical to set a defined limit for each of them as their contribution and interaction on the overall portfolio risk is likely to change over time.
- o SDGE: By limiting procurement expenditures, the PEL will inherently limit the VMOP. A second limit specifically for the VMOP would mean a cap within a cap – not only would this be impractical from a portfolio management standpoint, it would also be confusing for the Commission and parties to track.
- o LSA: LSA recommends the Commission defer any ruling on bounding the size of the utilities banks or VMOP as part of this RPS cycle due to SB 350.

Order: This decision denies the request to establish caps on each utility's VMOP. It is difficult to attribute rate hike to VMOP. PG&E and SDG&E are not procuring generation and the VMOP can be used towards meeting renewable shortfalls in future years. Moreover, the current VMOP will help the IOUs meet SB 350 requirements.

Changing market environments necessitates that utilities have the flexibility to manage their procurement positions to adapt to external circumstances.

Currently the Commission performs its oversight role by directing how an IOU reports its VMOP in the RNS.

1. In its respective annual RPS Plan, an IOU must provide a justification for its VMOP procurement of additional RECs for RPS compliance. The justification needs to be supported by quantitative analysis that explains an IOU's need for additional procurement over a specific time period and for a specified amount (RECs).
2. In its annual RPS Plan, an IOU must provide a cost-effectiveness showing of all available options that are being considered for VMOP procurement.

The Commission can monitor the VMOP levels in case of excess procurement.

11.7.2. The Commission should Finalize the Procurement Expenditure Limit (PEL)

Support: PG&E, ORA, SDGE

- SDG&E: The Commission should prioritize the completion of the PEL methodology.
- ORA: Commission should finalize the PEL considering that two of the three IOUs have surpassed their RPS procurement targets for CP 2 and CP 3.

Order: This request will be considered in 2016 as part of the SB 350 implementation.

11.7.3. The Commission should Review Utility Forecasted Failure Rate

Support: ORA, Defenders of Wildlife and Sierra Club

- ORA: If the Commission finds that forecasted failure rates are too inaccurate, then the Commission should require IOUs to improve their methodologies for accessing project failure in order to avoid unnecessary expenditures and potential rate shock. Due to low confidence levels in forecasted project failure rates, excess procurement may result from understated project failure rates coupled with overcompensated unforeseen risk (such as legislative changes)
- Defenders of Wildlife and Sierra Club: Proposes a benchmarking exercise – In this three-part exercise the Commission staff would first use their own methodology to calculate the risk-adjustment score for each individual project with an executed contract, next use these scores to risk-adjust each IOUs portfolio of projects in development, and finally, benchmark the Commission's risk-adjusted methodology against the IOU risk-adjusting methodology.

Oppose: SCE, SDGE

- SCE has a sufficiently developed process to determine project success rates and regularly considers the effectiveness of its forecasts.
- SDG&E: SDG&E continuously aligns success rate with actual values. An interdisciplinary team meets monthly to determine the proper probability weighting for each project within its portfolio. This group of experts is highly familiar with each project, and they are in the best position to assign the proper probability weighting.

Order: **A**s stated in the ALJ ruling dated May 21, 2014 at 12, the Commission is looking into these issues:

> The Commission will benchmark the individual project risk-adjustment scores calculated by the IOUs against the individual project risk-adjustment scores calculated by staff to

> identify outliers based on the difference between the two scores. If an outlier is identified through the benchmarking process, the Commission will ask an IOU to justify the validity of a risk-adjustment score assigned to the outlier in its annual RPS Plan. The Commission will then analyze an IOU's justification of an outlier and work with the IOU to determine the outlier score's reasonableness as part of approving the IOU's RPS plan. As part of the benchmarking process, the Commission may adjust the scoring and weighting system of the staff methodology to more accurately assess an individual project's viability.

As the information required for the benchmarking is currently being collected, this request is premature.

11.7.4. ORA Urges PG&E to Investigate Additional Tools to Mitigate the Great Variation between Sales Forecasts

Order: The Commission will grant ORA's request.

12. Comments on Proposed Decision

The proposed decision of ALJs Mason and Simon in this matter was mailed to the parties in accordance with Pub. Util. Code § 311. Opening comments were received on December 7, 2015 from CalWEA, GPI, IPEA, L. Jan Reid, LSA, PG&E, SCE, SDG&E, and UCAN. We summarize and resolve the comments below.

12.1. CalWEA

CalWEA asks that the decision be modified to expressly authorize the IOUs to offer amendments to existing PPAs, including PPAs executed under the RAM program, to allow the projects subject to those PPAs to utilize shared transformers and low-side metering.

CalWEA asks that two ordering paragraphs be added to reflect the decision's findings that the IOUs should include a description of how their process ensures that there is no double counting between the Integration Cost Adder and the NMV components in the LCBF methodology section of the RPS plan; and that the IOUs should permit shared facilities and low- side metering. The proposed ordering paragraphs are as follows:

- PG&E, SCE, and SDG&E shall include a description of how their process ensures that there is no double counting between the Integration Cost adder and Net Market Value components in the LCBF methodology section of the RPS plans.
- PG&E, SCE, and SDG&E shall revise their pro forma terms and conditions to expressly permit projects with shared facilities, including shared transformers, and projects using low-side metering. These utilities may, in addition, offer amendments to existing PPAs, including PPAs executed under the RAM program, to allow the projects subject to those PPAs to utilize shared transformers and low-side metering, and may file Tier 2 advice letters seeking approval of such amendments.

We agree with the first proposed ordering paragraph as it appears reasonable.

We disagree with the second proposed ordering paragraph as there may be contractual impediments that would prevent the rewriting of the existing contracts.

12.2. GPI

GPI offers three comments. First, with respect to resource diversity and LCBF reform, GPI asserts that the overhaul of LCBF should begin in 2016. Second, with respect project risks and margin of procurement, GPI asserts that due to the underestimation of the risks of project development, and with the overestimation of the amount of renewable electricity that will be procured, the

Commission should exercise greater oversight over the setting of adequate procurement margins to ensure that each IOU complies with its procurement obligations. Third, with respect to TOD factors, GPI supports the opening of a new OIR of TOD profiling since the current practice of TOD block profiling can lead to a variety of serious market distortions.

We decline to make any changes to the decision based on GPI's comments. These arguments were already taken into account in drafting the instant decision.

12.3. IEPA

IPEA argues that the decision's approval of SDG&E's proposal to pay $0/MWh for energy and RECs in excess of SDG&E's proposed limits fails to recognize that SDG&E, acting as the Scheduling Coordinator for the project, will bid the project's output into the CAISO's markets and receive all the revenues derived from those sales. As a result, IPEA asserts that SDG&E will receive a windfall while the seller receives nothing for its production.

To correct this situation, IPEA suggests that the decision should be modified to either require SDG&E to amend the proposed PPA to provide fair compensation for the energy and RECs delivered to SDG&E; or the PPA should be revised to state unambiguously that seller has the right to sell its energy, RECs, and other attributes associated with excess generation to a party other than SDG&E.

IPEA is also concerned with SCE's return of development security. It asserts that the decision's approval of SCE's plan to retain 100% of the development security posted by seller if seller is unable to meet the COD specified in the PPA due to an inability to obtain the necessary permits in time, fails to recognize that many factors outside of seller's control can delay the issuance of permits. It would be, in IPEA's estimation, unnecessarily right for SCE to retain development security without any consideration of the reasons permits were not obtained in time.

Accordingly, IPEA proposes that the decision should be revised to require SCE's PPA to provide for (1) consideration of the causes for permitting delays that delay COD, (2) day-for-day extensions of COD to account for reasonable permitting delays and force majeure events, (3) a reasonable period to cure any delays in achieving COD, and (4) a graduated draw-down of the development security during the cure period.

We agree that the decision should be clarified to require the PPA to state that seller has the right to sell its energy, RECs, and other attributes associated with excess generation to a party other than SDG&E.

With respect to the last four suggestions, with agree with (2), (3), and (4).

12.4. L. Jan Reid

L. Jan Reid makes two recommendations: first, the Commission should modify the PD and order PG&E to limit its procurement bank size to the number of annual GWh Reid recommended in Table 2 of his Confidential Comments. Second, the Commission should modify the PD and order the IOUs to establish escalation rates that are no greater than the annual inflation rate for the year in question.

Reid also points out an error in the text in the decision which states:

> Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1) today's decision accepts, with some modifications noted, the draft 2015 Renewables Portfolio Standard (RPS) Procurement Plans, includ- ing the related solicitation protocols, filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). (PD at 1)

L. Jan Reid notes that since PG&E did not file a solicitation protocol, the above text should delete the reference to PG&E.

We decline to make L. Jan Reid's changes as there are a repetition of his earlier comments that have already been considered. We also do not believe that there is an error in the text with respect to the reference to PG&E..

12.5. LSA

LSA supports the request to delay filing of the final RPS Plans until 30 days after the decision is issued, as well as a corresponding 16-day extension in the other dates for its 2015 RPS Solicitation.

LSA also asks that the decision be revised to correctly characterize negative pricing and curtailment events. It argues that while the decision has included the IOUs' information on recent system events and trends around negative pricing and curtailment, along with initiatives and strategies to manage these events, the decision lacks analysis of the reported information and fails to include information about the drivers of these events available in the record of this proceeding. It suggests that page 26 of the decision be revised to read:

> The specific occurrences of negative price periods and over generation events can **have multiple drivers but today are relatively small. Some of these drives are hard to predict. Other factors, like the congestion seen this year on Path 15 due to maintenance, are clear drivers of negative price periods andcan be anticipated.**

As we will explain, *infra*, we agree to modify the schedule. We decline to modify page 26 of the decision. LSA is basing this request based on a staff report that is not part of the record in this proceeding.

12.6. PG&E

PG&E supports the decision but requests that a correction be made with respect to discussion regarding SB 350. It asserts that the statement that SB 350 "Prohibits the use of any renewable energy credits [RECs] associated with electricity credited to a customer to be counted toward procurement requirements" is incorrect, unnecessary, and should be deleted.

We agree with PG&E's assessment and will delete the statement.

12.7. SCE

SCE suggests that the decision be modified in three respects; First, the decision should be revised to remove any requirement that the utilities allow shared transformers and low-side metering in their *pro forma* PPAs. Instead, SCE states it will consider projects with shared transformers and low-side metering in its 2015 RPS solicitation. Second, the Commission should permit

SCE to require at least one 10-year term proposal for each project in its 2015 RPS solicitation, because SCE believes the decision is incorrect in its assessment that such a requirement would constrain the market because sellers have the ability to propose bid prices that meet their project revenue requirements and expectations for different contract terms.

Finally, the Commission should briefly extend the filing date for the final 2015 RPS Procurement Plans set forth in the PD from 14 days to 30 days after the mailing date of the final decision to avoid a filing deadline that is during or immediately after the holidays. It proposes the following revised schedule:

Proposed Revised 2015 RPS Solicitation Schedule

Schedule for 2015 RPS Solicitation	**Item**	**No. of Days (cumulative)**
1	Mailing of Commission decision conditionally accepting 2015 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2015 RPS Procurement Plans	30~~14~~
3	SCE issues RFO (unless SCE's amended Plan~~s~~ is~~are~~ suspended by the Energy Division Director by Day 40~~24~~)*	40~~24~~

4	SCE submits shortlist~~s~~ to Commission and Procurement Review Group	136~~120~~
5	SCE files by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	166~~150~~
6	SCE 2015 RPS RFO Shortlists Expires	501~~485~~
7	SCE submits Advice Letters with contracts/power purchase agreements for Commission approval	TBD

SCE asserts that this revised schedule is consistent with the requirements of previous Commission decisions, including the requirement that SCE file its Tier 2 shortlist advice letter 100 days after the close of its solicitation and the expiration of the shortlist after 12 months, and references D.12-11-016 at 35-36 and D.14-11-042 at 71-72 in support.

We decline to adopt SCE's first two requests. As to the first request, we do not see how following SCE's suggestion would address the problems SCE highlights. As to the second request, we do not see a persuasive reason to require at least one 10-year term proposal for each project in its 2015 RPS solicitation.

Finally, we agree to extend the filing deadline and accept the new dates that SCE has proposed.

12.8. SDG&E

SDG&E raises a few areas of concern. First, it requests that the decision clarify the scope of the TOD issues that the Commission will consider later in this proceeding when the Commission considers LCBF reform, and suggests that Conclusion of Law 3 be amended as follows:

> It is reasonable to reject SDG&E's proposal to rely on the flat TOD factor of 1.0 for purposes of contract pricing because additional information is needed to assess this proposal <u>comprehensively in this proceeding.</u>

Second, SDG&E is concerned about the decision's allowance of shared facilities, specifically shared transformers and low-side meters. For example, SDG&E argues that, to date, the Commission has not developed a record for addressing problems such as how should utilities and generators sharing facilities deal with the circumstance when one generator encounters some significant issue that adversely affects the other generators. SDG&E asserts it is also unclear which type or types of PPA are implicated by the proposal. Finally, curtailment does not appear to be accounted for due the myriad of project configurations.

Third, SDG&E asks that the decision address SDG&E's October 7, 2015 Motion to update to clarify the contents of SDG&E's final 2015 RPS Plan. Specifically, the motion adds language to one sentence in the Plan's economic curtailment section, and updates two of its appendices (2015 Quantitative Information and 2015 Cost Quantification Table). SDG&E proposes the following edit to Ordering Paragraph 1:

> Pursuant to the authority provided in Pub. Util. Code Section 399.13(a)(1), the draft 2015 Renewables Portfolio Standard Procurement Plans, including the related Solicitation Protocols, <u>and including all October 7,2015 Motions to Update,</u> filed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are accepted, as modified in the Ordering Paragraphs that follow.

We agree to alter Conclusion of Law 3 but will not include the word "comprehensively" as it is vague and ambiguous.

SDG&E has not raised any credible arguments to cause us to change the decision's allowance for shared facilities (i.e. shared transformers and low-side meters).

Finally, with respect to SDG&E's October 7, 2015 motion, it is granted, in part, and denied, in part. The motion is granted with respect updating two of its appendices (2015 Quantitative Information 2015 Cost Quantification Table). The motion is denied, without prejudice, as to SDG&E's plans to address all contracts, including RAM legacy contracts to the extent the Commission has previously approved such provisions in the most recent RAM VI PPA, that require updates due to CAISO's implementation of FERC Order 764. While SDG&E finds the update to be self-explanatory, we do not see that the record is sufficiently developed to allow the Commission to grant such a request at this time.

12.9. UCAN

UCAN has decided not to file opening comments, but reserves the right to file reply comments.

13. 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.

14. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Anne E. Simon and Robert M. Mason III are the co-assigned ALJs in this proceeding.

Findings of Fact

1. All retail sellers filing 2015 RPS Procurement Plans incorporated a section on safety considerations regarding the procurement of electricity in their RPS annual procurement plan filing.

2. The IOUs' 2015 RPS Plans do not seek authorization for renewable procurement in excess of the current RPS Program's 33% requirement.

3. Aegra Energy, LLC, Direct Energy Services, EnerCal (dba Yep Energy). Glacial Energy of California, Inc., and Mansfield Power and Gas did not file required 2015 RPS Procurement Plans.

4. More certainty is needed regarding whether SDG&E's proposal to rely on the flat TOD factor of 1.0 for purposes of contract pricing will discourage

generators to minimize the cost of their bid by providing a generation profile that places more generation in the off-peak hours.

5. By keeping the documents related to the solicitation current, SDG&E will promote market transparency even though it will not hold a 2015 solicitation.

6. PG&E's and SDG&E's showing regarding its compliance with current statutory RPS procurement mandates justifies granting PG&E's SDG&E's request to not holding a solicitation in 2015.

7. Shortlist exclusivity may reduce transaction costs but shortlist exclusivity continues to be an unnecessary restriction on the market based on the current level of competition.

8. The proposed changes to the excess capacity provisions in the pro forma contracts will limit customer exposure to incremental costs. If a seller would like to produce more energy, the seller is encouraged to offer a higher contract capacity during the bidding process.

9. Occurrences of negative locational marginal pricing are increasing.

10. The IOUs are working to minimize or avoid the need for curtailment.

11. Increases in intermittent renewable generation may require the grid system to be more operationally flexible to ensure adequate system reliability.

Conclusions of Law

1. The 2015 draft RPS Procurement Plans, as updated or amended, are acceptable in terms of the information provided on safety considerations.

2. PG&E's request to reply on one set of TOD factors is reasonable because different technologies are treated consistently with respect to obtainment of FCDS.

3. It is reasonable to reject SDG&E's proposal to rely on the flat TOD factor of 1.0 for purposes of contract pricing because additional information is needed to assess this proposal in this proceeding.

4. It is reasonable to authorize IOUs to update their TOD factors to be uniform across all RPS programs because uniformity supports fairness.

5. Each utility remains responsible for meeting its RPS Program procurement requirements implemented in D.11-12-020.

6. SDG&E's request to update its solicitation materials is reasonable because, in this manner, SDG&E will keep the documents current even if no 2015 solicitation is held.

7. Based on PG&E's and SDG&E's current stated compliance with RPS procurement, it is reasonable to approve of PG&E's and SDG&E's requests not to hold a 2015 solicitation.

8. Affirming our finding in D.14-11-042 that the contract negotiating arrangement referred to as *shortlist exclusivity* will not be permitted is reasonable because it is an unnecessary restriction on the market based on the current level of competition.

9. It is reasonable for the IOUs to modify their pro forma contracts consistent with SDGE's suggested modification to the excess delivery provisions because the seller and utility agree on a contract quantity and expect the seller to construct a facility consistent with the terms of the contract.

10. It is reasonable to approve of the terms and conditions regarding curtailment set forth in the IOUs' 2015 RPS Procurement Plan because the provisions provide some ratepayer protection against the risk of negative locational marginal pricing and also allow the contracts to be financeable.

11. All motions for confidential treatment should be granted.

12. All motions for party status should be granted.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1), the draft 2015 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, as modified in the Ordering Paragraphs that follow.

2. Pacific Gas and Electric Company(PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall file final Renewables Portfolio Standard (RPS) Procurement Plans with the Commission to initiate the RPS solicitation process within 30 days of the mailing date of this decision pursuant to the RPS solicitation schedule adopted in Ordering Paragraph 13.

3. The 2015 Renewables Portfolio Standard Procurement Plans filed by Bear Valley Electric Service and Liberty Utilities LLC are accepted and deemed final. No further filings are required.

4. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2015 Renewables Portfolio Standard Procurement Plans filed by electric service providers are accepted and deemed final, including: 3 Phases Renewables, Calpine PowerAmerica-CA, LLC's, Commerce Energy, Inc., Commercial Energy of California, Constellation NewEnergy, Inc., Direct Energy Business LLC, LLC, EDF Industrial Power Services, LLC, Gexa Energy California, LLC, Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Palmco Power

CA, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P. The Regents of the University of California, and Tiger Natural Gas, Inc.

5. Aegra Energy, LLC, Direct Energy Services, EnerCal (dba Yep Energy). Glacial Energy of California, Inc., and Mansfield Power and Gas shall file 2015 RPS Procurement Plans consistent with the assigned Commissioner Ruling within 14 days of the mailing of this decision.

6. PacifiCorp's April 30, 2015 2015 On-Year Supplement to its 2015 Integrated Resource Plan and July 28, 2015 Addendum to its On-Year Supplement to its 2015 Integrated Resource Plan are deemed final. No further filings are required.

7. In the final 2015 Renewables Portfolio Standard (RPS) Procurement Plans filed with the Commission pursuant to the schedule adopted herein: (1) Pacific Gas and Electric Company (PG&E) is authorized to rely on one set of Time-of-Delivery (TOD) factors; (2) Southern California Edison Company (SCE) is authorized to rely on a single set of TOD factors as set forth in its 2015 draft Procurement Plan; (3) San Diego Gas & Electric Company (SDG&E) shall update its TOD factors and remove the flat-rate component. In addition, any Tier 1 Advice Letters to request the Commission to approve of conforming TOD factors across all the RPS Procurement Programs shall be served on the Rulemaking 15-02-020 service list, or then current RPS proceeding, and any entities in RPS Procurement queues; (4) PG&E, SCE, and SDG&E shall include a description of how their process ensures that there is no double counting between the Integration Cost adder and Net Market Value components in the Least-Cost Best-Fit methodology section of their RPS plans; (5) SDG&E October 7, 2015 motion is granted as to its request to update its appendices (2015 Quantitative Information and 2015 Cost Quantification Table), and

denied, without prejudice, with respect to its plans to address all contracts, including Rate Adjustment Mechanism (RAM) legacy contracts to the extent the Commission has previously approved such provision in the most recent RAM VI power purchase agreements (PPA), that require updates due to California Independent System Operator's implementation of Federal Energy Regulatory Commission's Order 764; (6) the PPAs shall be revised to state that a seller has the right to sell its energy, Renewable Energy Credits, and other attributes associated with excess generation, to a party other than SDG&E; and (7) SCE's PPA shall provide for day-for-day extensions of Commercial Operation Dates (COD) to account for reasonable permitting delays and force majure events, a reasonable period to cure any delays in achieving COD, and a graduated draw-down of the development security during the cure period.

8. San Diego Gas & Electric Company (SDG&E) is authorized to not hold a 2015 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2015 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 2015 solicitation cycle.) SDG&E shall file a final 2015 RPS Procurement Plan with updated solicitation material even though no solicitation is scheduled for 2015. This authorization to not hold a solicitation only applies for one year, 2015.

9. Pacific Gas and Electric Company (PG&E) is authorized to not hold a 2015 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2015 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 2015 solicitation cycle.) This authorization to not hold a solicitation only applies for one year, 2015.

10. Consistent with Decision (D.) 13-12-024 and D.14-11-042, in the final 2015 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are not authorized to require shortlist exclusivity as part of the contract negotiating process.

11. In the 2015 Renewables Portfolio Standard Procurement Plans filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company and San Diego Gas & Electric Company are authorized to incorporate the excess delivery terms set forth in their draft plans.

12. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall continue to incorporate and describe how expected economic curtailment affects their Renewables Portfolio Standard (RPS) procurement in future RPS procurement plans. SCE's and SDG&E's *pro forma* terms and conditions related to economic curtailment are approved as proposed. SCE shall include in its 2015 RPS solicitation shortlist report information regarding how economic curtailment was considered in its shortlisting processes.

13. The following schedule is adopted for the 2015 Renewable Portfolio Standard:

Schedule for 2015 RPS Solicitation Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission	0

	decision conditionally accepting 2015 RPS Procurement Plans	
2	PG&E, SCE and SDG&E file final 2015 RPS Procurement Plans	30
3	SCE issues RFO (unless SCE's amended Plan is suspended by the Energy Division Director by Day 40)	40
4	SCE submits shortlists to Commission and Procurement Review Group	136
5	SCE files by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	166
6	SCE 2015 RPS RFO Shortlists Expires	501
7	SCE submits Advice Letters with contracts/power purchase agreements for Commission approval	TBD

14. The Energy Division Director is authorized, after notice to the service list of this proceeding, to change the schedule adopted in Ordering Paragraph 13 above as appropriate or as necessary for the efficient administration of the 2015 Renewables Portfolio Standard solicitation process.

15. All motions for confidentiality as to the 2015 Renewable Portfolio Standard Plans are granted.

16. All motions for party status in this proceeding are granted.
17. Rulemaking 15-02-020 remains open.

This order is effective today.

Dated December 17, 2015, at San Francisco, California

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners