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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 12, 2018)

SUBMISSION BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) OF ITS FINAL, CONFORMING 2019 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

MARIA VANKO WILSON

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-5639
Facsimile: (415) 973-5520
E-Mail: Maria.Wilson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 29, 2020

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OF THE STATE OF CALIFORNIA

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Pursuant to Ordering Paragraph 2 of California Public Utilities Commission's ("Commission") Decision ("D.") 19-12-042, Pacific Gas and Electric Company ("PG&E") is submitting its Final, Conforming 2019 Renewable Energy Procurement Plan ("Final 2019 RPS Plan"). The Final 2019 RPS Plan is attached to this cover pleading in both a clean version and a redline version showing changes made to its Revised Draft 2019 RPS Plan filed on June 21, 2019.

The changes made in the Final 2019 RPS Plan conform it to the requirements and modifications authorized and set forth in D.19-12-042. In summary, these changes include:

1. Clarifying that PG&E will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission;[1]
2. Updating PG&E's Renewable Energy Credit (REC) sales framework to conform to modifications ordered by D.19-12-042;[2] and
3. Including new informational-only Time of Delivery (TOD) Factors that are based on the most recent inputs that are available.[3]

Pursuant to D. 19-12-042, PG&E will deem its Final 2019 RPS Plan to be accepted by

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[1] D.19-12-042, Ordering Paragraph ("OP") 18 and OP 20.

[2] *Id.*, OP 16.

[3] *Id.*, OP 26.

the Commission unless this filing is suspended by the Energy Division by February 8, 2020 which is 10 days from the date of this submission.[4]

Respectfully Submitted,

MARIA VANKO WILSON

By: */s/ Maria Vanko Wilson*
MARIA VANKO WILSON

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-5639
Facsimile: (415) 973-5520
E-Mail: Maria.Wilson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 29, 2020

[4] *Id.*, OP 2.

VERIFICATION

I, Marino Monardi, am an employee of Pacific Gas and Electric Company, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing:

SUBMISSION BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) OF ITS FINAL, CONFORMING 2019 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 29th day of January, 2020 at San Francisco, California

/s/ Marino Monardi
MARINO MONARDI
Director, Structured Energy Transactions
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL, CONFORMING 2019 RENEWABLE ENERGY PROCUREMENT PLAN

JANUARY 29, 2020

PUBLIC VERSION

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LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its Final, Conforming 2019 Renewables Portfolio Standard ("RPS") Plan ("2019 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Commission in the *Assigned Commissioner And Assigned Administrative Law Judge's Ruling Identifying Issues And Schedule Of Review For 2019 Renewables Portfolio Standard Procurement Plans* (the "2019 RPS Plan Ruling").[1] PG&E's 2019 RPS Plan begins with summaries of the key changes from the 2018 RPS Plan, identifies key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the other specific requirements identified in the 2019 RPS Plan Ruling and other Commission decisions and statutes.[2]

1. Summary of Key Updates

This Section describes the most significant changes between PG&E's Final 2018 RPS Plan and its Draft 2019 RPS Plan as filed on June 21, 2019. A complete redline of the Final, Conforming 2019 RPS Plan against PG&E's Draft 2019 RPS Plan is included as Appendix K. The table below provides a list of key differences between the 2018 and 2019 RPS Plans:

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1 2019 RPS Plan Ruling, filed April 19, 2019 in Rulemaking ("R.") 18-07-003, p. 28 (Ordering Paragraph ("OP") 1. PG&E's Final, Conformed RPS Plan contains limited revisions and additions ordered by Decision ("D.") 19-12-042.

2 *See* 2019 RPS Plan Ruling, pp. 3-24, Appendix B (providing a template for retail sellers to use in drafting their respective RPS Plans). *See also* D.18-12-003, OP 3 (requiring PG&E to include a Framework for Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation in its RPS Plan; Public Utilities Code ("Pub. Util. Code") § 2837 (requiring PG&E's RPS Plan to address energy storage).

TABLE 1-1
SUMMARY OF CHANGES

Reference	Area of Change	Summary of Change and Explanation and Justification
Section 10 and Appendices E and F	RPS Sales Framework, Sales Confirm, and Sales Solicitation Protocol	Updated to take into account market and regulatory changes. Specifically, PG&E is updating its RPS Sales Framework that guides its evaluation of RPS sales opportunities, its Form Confirmation for Short-Term RPS Sales, and its Sales Solicitation Protocol for use in the 2019 RPS Plan cycle.
Section 10.C.1 and Appendix J	Informational-Only Time of Delivery ("TOD") Factors	In its decision approving the 2018 RPS Plans, the Commission required PG&E to provide proposed informational-only TOD factors.[a] PG&E filed this proposal in R.18-07-003 jointly with the other investor-owned utilities ("IOUs") on May 29, 2019. The proposal stated that PG&E would include the informational-only TOD factors in each subsequent RPS Plan filing. Subsequently, D.19-42-042 approved the methodology and ordered TOD factors be updated in the final 2019 RPS plans. Accordingly, PG&E provides a description of informational-only TOD factors, and attaches those TOD factors as Appendix J.

TABLE 1-1
SUMMARY OF CHANGES
(CONTINUED)

Reference	Area of Change	Summary of Change and Explanation and Justification
Former Appendices C (Deleted in Draft 2019 RPS Plan)	Stochastic Modeling Variability	As part of PG&E's ongoing efforts to streamline the RPS Plan and to focus the plan on outcomes, PG&E is eliminating this Appendix as an unnecessary level of detail.

(a) D.19-02-007, p. 118 (OP 17).

2. Executive Summary—Summary of Key Issues

2.1 PG&E Has No Current Need for Additional RPS Resources, Although Foreseeable Future Events Could Significantly Change That Need

PG&E is currently well-positioned to meet its RPS compliance requirements. Based on its existing RPS portfolio, demand forecasts, and RPS sales assumptions for planning purposes, PG&E does not project to have incremental physical need[3] for RPS resources until at least 2029. This RPS need year moves beyond 2033 (the "optimized

3 "Incremental physical need," as used in this RPS Plan, describes a situation in which actual deliveries from RPS resources in a given year or compliance period are less than the corresponding RPS interim target or compliance period requirement. Where PG&E has an incremental physical need, excess volumes of RPS procurement carried forward from past years may be used in part to meet any applicable RPS compliance target.

need year") assuming that PG&E applies volumes of RPS procurement above the requirements from past years ("Bank") once it has a physical need.[4,5,6]

However, PG&E's RPS need is subject to considerable uncertainty, including the following:

1. The Commission's review of portfolio optimization in the recently-initiated Phase 2 of the Power Charge Indifference Adjustment ("PCIA") reform proceeding[7] may result in changes to PG&E's RNS position if the Commission orders sales or allocation of PG&E's existing RPS portfolio.
2. Due to PG&E's bankruptcy,[8] PG&E will be developing a restructuring proposal pursuant to Chapter 11 of the United States Bankruptcy Code.[9] For purposes of this 2019 RPS Plan, PG&E assumed that its existing RPS contracts will continue in effect until expiration. Specifically, as part of its restructuring, PG&E will develop a Plan of Reorganization ("POR") that may assume or reject certain contracts, including RPS contracts entered into prior to the bankruptcy filing. PG&E has not decided on the

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4 PG&E's planning assumptions for future additional RPS sales and RPS bank optimization are included in PG&E's Alternate Renewable Net Short ("RNS") provided in Appendix A.2.

5 In prior versions of its RPS Plan, PG&E has redacted its RPS need year, consistent with the May 21, 2014, Administrative Law Judge's ("ALJ") Ruling on RNS issued in R.11-05-005, pages 5 and 24, which established confidentiality rules associated with portfolio optimization. PG&E is waiving this confidentiality in this limited instance in order to allow for public transparency concerning PG&E's proposals to manage its RPS portfolio and concerning PG&E's need for incremental mandated procurement. In doing so, PG&E reserves the right to redact its need year and similar portfolio optimization information in future versions of its RPS Plan. The ability to redact future need is particularly critical when PG&E expects a near-term net short position.

6 Assuming both the maximum volume of sales proposed in the this RPS Plan cycle and additional planned future RPS sales forecasted in PG&E's RNS are executed and approved, PG&E projects that it would have an incremental RPS procurement need after [redacted] after application of its Bank.

7 R.17-06-026.

8 Nothing in this RPS Plan shall be deemed to constitute an assumption of any contract or a waiver or modification of the Debtors' rights to assume, assume and assign, or reject any contract pursuant to the federal bankruptcy code.

9 PG&E's federal bankruptcy proceeding commenced with its January 29, 2019 Chapter 11 bankruptcy filing at the United States Bankruptcy Court, Northern District of California, Case Nos. 19-30088-DM and 19-30089-DM.

assumption or rejection of any pre-petition RPS contracts at the time of this 2019 RPS Plan filing. To the extent an approved POR results in changes to PG&E's RPS portfolio, the associated volumes of deliveries would correspondingly change PG&E's forecast of deliveries and the RNS.

3. Expected increases in customers switching to service from Community Choice Aggregators ("CCA") and generating their own electricity have resulted in dramatic decreases in the IOUs' bundled retail sales projections. As retail sales decrease, the quantity of RPS energy required for PG&E to meet its RPS obligation falls, resulting in a decreased need for new RPS resources.
4. This 2019 RPS Plan assumes the current RPS law remains unchanged and that the Commission does not exercise its authority to raise the RPS requirements for retail sellers. However, legislation enacted after this date and actions taken in the Commission's RPS proceeding can change these inputs.

2.2 PG&E Proposes Not to Hold a Voluntary Solicitation to Buy RPS Products During the 2019 RPS Plan Cycle

Given its current RPS compliance position, PG&E is proposing not to hold a voluntary annual RPS solicitation to buy incremental RPS products during the 2019 RPS Plan cycle. PG&E will seek Commission approval to procure any incremental RPS products during this RPS Plan cycle, other than amounts resulting from the mandated programs referenced below. In the event that PG&E decides to hold a 2019 RPS solicitation to procure incremental RPS products, or to execute bilateral contracts for incremental RPS procurement, PG&E will first seek permission from the Commission in a manner consistent with the Commission's Rules of Practice and Procedure.

Although many factors, including those described above, could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be more than adequate to ensure compliance with near-term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs during the 2019 RPS Plan cycle (which is expected to occur during the calendar year 2020).[10]

2.3 PG&E Plans to Continue to Sell RPS Volumes During the 2019 RPS Plan Cycle

In response to load departure and PG&E's resulting long RPS position, PG&E plans to manage its RPS portfolio to meet the needs of its bundled customers through continued offers to sell RPS volumes during the 2019 RPS Plan cycle. PG&E proposes to pursue short-term RPS sales during the 2019 RPS Plan cycle for deliveries in 2020 and 2021.

Pursuant to its approved 2019 RPS Plan, PG&E plans to issue 2-3 solicitations for short-term sales of RPS products during 2019. PG&E has used, and will continue to use, its RPS Sales Framework to assess short-term sales opportunities. PG&E is updating the RPS Sales Framework as part of this 2019 RPS Plan and intends to use the revised RPS Sales Framework, if approved, to target issuing three, with a minimum of two, short-term sales solicitations in 2020.[11]

The goal of PG&E's RPS Sales Framework is to prudently manage PG&E's portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program and preserving optionality for the outcome of the PCIA Phase 2 proceeding. If the market conditions support sales at the highest levels allowed under

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10 Mandated RPS programs include the Renewable Market Adjusting Tariff ("ReMAT"), the Bioenergy Market Adjusting Tariff ("BioMAT"), and any new or extended biomass contracts pursuant to Senate Bill ("SB") 901. The ReMAT program is currently suspended due to litigation, and the Commission has issued a new Order Instituting Rulemaking ("OIR") to consider further implementation of the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA"), which will consider adoption of a new mandate to procure from RPS-eligible facilities that are Qualifying Facilities ("QF") under federal law. *See generally* R.18-07-017. In addition, while it will not directly impact PG&E's RNS, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

11 Additional detail on PG&E's planned sales solicitations is described in Section 10.

the proposed revisions to the RPS Sales Framework, the incremental volumes of sales would be approximately [redacted] gigawatt-hours ("GWh") in 2020 and [redacted] GWh in 2021 based on the RNS table in Appendix A.2. This compares to PG&E's maximum annual sales volume of [redacted] GWh under the approved 2018 RPS Plan. The actual volumes of sales executed and approved in the 2019 RPS Plan cycle will be incorporated into PG&E's RNS calculations going forward and included in future RPS Plans.

2.4 PG&E Opposes Procurement Mandates That Result in Unnecessary and/or Unreasonable Costs for Its Bundled Customers

Despite PG&E's absence of need for additional RPS resources, PG&E is continuing in 2019 to procure required RPS-eligible volumes through mandated procurement programs, such as the BioMAT program. In 2018, for example, PG&E held 12 auctions/solicitations[12] to fulfill mandated program requirements, despite being granted approval by the Commission to not hold an RPS solicitation due to lack of RPS need.

Wherever consistent with law, PG&E will continue to oppose new RPS procurement mandates, seek to suspend existing RPS procurement mandates, and oppose any changes to existing RPS procurement mandates that would require PG&E to conduct additional RPS procurement. In general, PG&E believes that no RPS procurement should be mandated without a clear demonstration of need.

Even if PG&E had near-term RPS need, PG&E would still not support expansion of existing mandated programs or additional new mandated programs. Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-

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12 PG&E has held bi-monthly auctions for ReMAT since November 1, 2013 (until the program was suspended at the end of 2017, as further described below) and for BioMAT since February 1, 2016. PG&E also held one PV RAM solicitation in 2018.

neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

PG&E continues to be concerned about the cost burden that procurement mandates place on bundled customers and will seek to ensure all customers, both bundled and departed load, equitably bear the costs of additional and existing mandates. Mandated procurement through Bioenergy Renewable Auction Mechanism ("BioRAM"), BioMAT, ReMAT, and the Photovoltaic Program - RAM ("PV RAM") benefits all customers and thus all customers should pay their equitable share of those costs.

Finally, PG&E is open to the concept under discussion in the State Legislature regarding the establishment of a state entity that would be a central buyer for purposes of providing a backstop to ensure that all entities meet their RPS obligations and to procure resources of statewide benefit.

2.5 PG&E Will Continue to Comply with the RPS and Manage Its RPS Portfolio During Bankruptcy

PG&E remains committed to supporting California's clean energy goals, including the RPS, during its restructuring process under Chapter 11 of the United States Bankruptcy Code. As demonstrated by this RPS Plan, PG&E continues to manage its RPS portfolio to achieve compliance in a least-cost, best-fit ("LCBF") manner for its customers. As noted above, PG&E's RPS portfolio may change as a result of its bankruptcy restructuring.

3. Summary of Recent Legislative and/or Regulatory Changes

The following section summarizes key legislative and regulatory developments since PG&E's Final, Conforming 2018 RPS Plan[13] that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the implementation of SB 237;[14]

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13 Discussions on past legislative and regulatory changes (SB 100, SB 350, BioRAM) can be found in PG&E's Final, Conforming 2018 RPS Plan.

14 SB 237, Stats. 2018, Ch. 600 (Hertzberg).

(2) the implementation of SB 100;[15] (3) the implementation of SB 901[16] and BioRAM; (4) the approved Diablo Canyon Retirement Joint Proposal Application; and (5) the pending PCIA reform proceeding at the Commission.

3.1 Implementation of SB 237

SB 237, signed by Governor Brown on September 20, 2018, increases the participation cap for the State's Direct Access ("DA") program by 4,000 GWh statewide. The Commission initiated R.19-03-009 to implement SB 237 on March 21, 2019. On June 3, 2019, the Commission issued D.19-05-043 and determined that the earliest enrollment date for the expansion is January 1, 2021.[17] The apportionment of the 4,000 GWh will occur over two years and will be split in half and apportioned evenly to customers on the 2019 waitlist and on the upcoming 2020 waitlist. PG&E's apportionment of ~1,900 GWh will also be split between the 2019 and 2020 waitlist.

3.2 Implementation of SB 100

On September 10, 2018, Governor Brown signed SB 100, known as the 100 Percent Clean Energy Act of 2018. SB 100 increases the statutory RPS requirements to 44 percent by the end of 2024; 52 percent by the end of 2027; and 60 percent by 2030 and thereafter. PG&E's quantitative analysis in this 2019 RPS Plan, including its RNS tables, reflects these increased targets. Separately, SB 100 adopts a statewide policy that 100 percent of California's retail sales must come from RPS-eligible and zero-carbon resources by 2045. The Commission issued a Proposed Decision on May 22, 2019 to implement revisions to the RPS Procurement Quantity Requirements ("PQRs")[18] for years beginning in 2021. The Proposed Decision may be

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15 SB 100, Stats. 2018, Ch. 312 (De León).

16 SB 901, Stats. 2018, Ch. 626 (Dodd).

17 Note: D.19-05-043 was issued after the DA modeling was completed for the 2019 RPS Plan. As such, the model underlying this Draft 2019 RPS Plan assumes DA expansion would begin in 2020.

18 The PQR for any given multi-year RPS compliance period reflects the total volume of RPS-eligible procurement required in order to achieve compliance with the entire compliance period RPS requirement.

considered for adoption by the Commission, at the earliest, at the June 27, 2019 meeting. The straight-line methodology adopted by the Proposed Decision for determining the PQRs after 2020 is consistent with the modeling assumptions and methodologies used in this 2019 RPS Plan.

3.3 Implementation of SB 901 and BioRAM

SB 901, signed by Governor Brown on September 21, 2018, requires the IOUs to seek to extend the delivery terms of RPS-eligible biomass contracts that meet certain feedstock and other requirements. The Commission issued Resolution ("Res.") E-4977 on February 6, 2019, which amends the BioRAM Program pursuant to SB 901 and requires PG&E to seek additional procurement from certain BioRAM and other biomass contracts pursuant to criteria of California Pub. Util. Code Section 8388. PG&E has executed and submitted for Commission approval an amendment with one of its BioRAM counterparties to comply with some of the requirements established by Res.E-4977 and SB 901. PG&E continues to negotiate with counterparties that own RPS-eligible biomass facilities that meet certain feedstock and other requirements to comply with each of its remaining obligations under Res.E-4977 and SB 901. The Tree Mortality Non-Bypassable Charge D.18-12-003 determined that deliveries from BioRAM contracts will not be used for RPS compliance. As such, deliveries from eligible biomass facilities under SB 901 will not be reflected in PG&E's RNS tables for the purposes of RPS compliance.

3.4 Diablo Canyon Retirement Joint Proposal Application

On August 11, 2016, PG&E and the Joint Parties[19] filed an Application requesting Commission approval of the retirement of Diablo Canyon nuclear power plant. The Commission issued D.18-01-022 on January 16, 2018, approving PG&E's proposal to retire Diablo Canyon, stating the Commission's intent to avoid greenhouse

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19 Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility.

gas ("GHG") emissions increase from Diablo Canyon's retirement, and that the need for replacement procurement should be addressed in the Integrated Resource Plan ("IRP") proceeding. On September 19, 2018, Governor Brown signed SB 1090[20] that would, among other things, require the Commission to ensure the IRPs filed by retail sellers avoid any increase in GHG emissions as a result of retiring the Diablo Canyon nuclear power plant. Finally, in D.19-04-040, the Commission ordered that all Load-Serving Entities ("LSEs") serving load within PG&E's service area include in its subsequent IRP filing a section describing its plan to address the retirement of the Diablo Canyon Generation Plant.

3.5 OIR to Review, Revise, and Consider Alternatives to the PCIA

The Commission issued an OIR to Review, Revise, and Consider Alternatives to the PCIA on June 29, 2017 (the PCIA OIR).[21] PG&E is committed to developing PCIA reform solutions that treat all customers fairly and equally and that support California's clean energy goals.

On October 11, 2018 the Commission issued D.18-10-019 modifying the PCIA methodology. D.18-10-019 determined that a second phase of the proceeding would be opened in order to further define details around the PCIA True-Up, Prepayment of PCIA, IOU Portfolio Optimization, and various other implementation items. On February 1, 2019 the Commission issued a scoping memo in R.17-06-026 directing the parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission (the "Phase 2 Scoping Memo").

The working group most likely to have a significant impact on PG&E's RPS planning and RNS position is Working Group Three, which is focused on portfolio optimization. Parties are considering various methodologies to optimize the RPS portfolio of the large IOUs, including management of the IOU RPS Bank. Accordingly, the outcome of Phase 2 of the PCIA rulemaking could have a material impact on

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[20] SB 1090, Stats. 2018, Ch. 561 (Monning).

[21] See R.17-06-026.

PG&E's RPS need. Pursuant to the procedural schedule established in the Phase 2 Scoping Memo, the Commission plans to issue a decision regarding portfolio optimization by the second quarter of 2020.

4. Assessment of RPS Portfolio Supplies and Demand

A core component of PG&E's overall RPS planning framework is an assessment of PG&E's portfolio need, or lack thereof, for incremental RPS resources. This component has been well established and refined over time and remains largely consistent between this and the previous PG&E RPS Plan filings and is described in detail in this section.

As PG&E continues to find lack of incremental procurement need in recent planning cycles, PG&E has developed and added an RPS Sales component to its overall planning framework. As highlighted in the Summary of Key Updates, PG&E has further revised this RPS Sales component since the 2018 RPS Plan filing and is providing a full description of the changes in Section 10 of this Plan.

4.A. Portfolio Supply and Demand

4.A.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's RPS targets. Under existing law,[22] PG&E is required through 2030 to retire sufficient numbers of Renewable Energy Credits ("RECs") from RPS-eligible products to meet the following RPS requirements:

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22 Compliance period requirements shown below are based on D.11-12-020 and D.16-12-040, which implemented the targets established by SB 2(1X) and SB 350, respectively. PG&E is assuming, for purposes of this 2019 RPS Plan, that the Commission will implement the SB 100 revised targets in the same "straight-line" manner as it implemented prior versions of the statutory RPS targets. A Proposed Decision implementing SB 100 in a manner consistent with this assumption is pending in R.18-07-003 but will not be acted upon prior to filing of this Draft 2019 RPS Plan.

- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (27.0% * 2017 retail sales) + (29.0% * 2018 retail sales) + (31.0% * 2019 retail sales) + (33.0% * 2020 retail sales);
- 2021-2024: A percentage of the combined bundled retail sales that is consistent with the following formula: (35.8% * 2021 retail sales) + (38.5% * 2022 retail sales) + (41.3% * 2023 retail sales) + (44.0% * 2024 retail sales);
- 2025-2027: (46.7% * 2025 retail sales) + (49.3% * 2026 retail sales) + (52.0% * 2027 retail sales); and
- 2028-2030: (54.7% * 2028 retail sales) + (57.3% * 2029 retail sales) + (60.0% * 2030 retail sales).

Based on preliminary results presented in Appendix A.2, PG&E delivered 38.9 percent of its power from RPS-eligible renewable sources in 2018.

As described more fully in Section 8 and reported in the current RNS calculations in Appendix A.2, PG&E is well-positioned to meet its RPS compliance requirements through the fifth compliance period (2025-2027) and does not project to have incremental physical need for RPS resources until at least 2029. Additionally, based on PG&E's existing portfolio, under the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter, PG&E projects that it would have an incremental RPS procurement need after 2033, assuming the additional RPS sales forecasted in PG&E's Alternate RNS provided in Appendix A.2 are executed and approved and its Bank is applied to meet its RPS needs.[23]

PG&E's RNS is subject to future regulatory and legislative changes, including portfolio changes ordered as part of the ongoing PCIA OIR. PG&E's RPS position will be updated annually to reflect any sales of RPS volumes.

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23 Assuming both the maximum volume of sales proposed in this RPS Plan cycle and additional planned future RPS sales forecasted in PG&E's RNS are executed and approved, PG&E projects that it would have incremental RPS procurement need after [redacted]

4.A.2. Supply

4.A.2.1. Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 7,000 megawatts ("MW") of projects online or under development,[24] ranging from the following: (a) utility-owned solar and small hydro generation; (b) long-term RPS contracts for large wind, geothermal, solar, and biomass generation; and (c) small Feed-In Tariff ("FIT") contracts for solar photovoltaic ("PV"), biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 7 and 8.

As described in further detail in Section 7.2, to model the project failure variability inherent in project development, PG&E assumes that project viability for a to-be-built project is a function of the number of years until its contract start date. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations.

Consistent with the project trends reported in its 2018 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have helped the development of the market for renewables. PG&E expects renewables to continue to be cost-competitive in the future, whether or not the ITC and PTC are extended. Progress in the siting and permitting of projects also has supported PG&E's sustained high success rate. As described in more detail in this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

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24 Less than 100 MW of PG&E's existing portfolio is under development.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in the remainder of Section 4.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 7, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted.

4.A.3. RPS Market Trends and Lessons Learned

As its renewable resource portfolio has expanded to meet RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the following four key goals: (1) reaching, and sustaining, the existing RPS targets; (2) minimizing customer cost within an acceptable level of risk; (3) ensuring PG&E maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty; and (4) aligning PG&E's RPS portfolio to its customers' needs.[25] PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape. This strategy could significantly change depending on the outcome in the PCIA OIR.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

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25 In the future, PG&E's renewable resource strategy will also consider the directives of the Commission's integrated resources planning process.

Another trend, driven by the growth of renewable resources in the California Independent System Operator ("CAISO") system, is the downward movement of mid-day wholesale energy market prices. Many renewable energy project types have minimal operating costs, and therefore additions of these renewables tend to move wholesale energy market clearing prices down. This has led to a change in the energy values associated with RPS offers, with decreasing value for renewable projects that generate during mid-day hours.

The growth of renewable resources also has produced challenges, such as negative wholesale energy market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address negative pricing situations that are likely to increase in the future. These provisions have customer benefits. Economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 12.

4.A.4. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Key RPS compliance requirements were established in D.11-12-020, D.12-06-038, and D.16-12-040. These requirements will need to be modified by the Commission to incorporate the revised statutory RPS targets in the recently enacted SB 100.

One RPS compliance criterion of particular importance is that involving the need to ensure a balanced RPS portfolio. Implementing Pub. Util. Code Section 399.16, the Commission issued D.11-12-052 to define three statutory portfolio content categories ("PCC") of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. The ultimate effect of these portfolio balancing requirements is to significantly increase the demand of LSEs, including PG&E, for resources that are directly interconnected or deliver in real time to a California Balancing Authority like CAISO.

Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 7; in particular, uncertainty regarding bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

4.A.4.1. Near-Term Need for RPS Resources

Because PG&E currently has no incremental procurement need until after 2033 under existing RPS requirements, PG&E is proposing to not hold an RPS solicitation during this RPS Plan cycle. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for any future Request for Offers ("RFO") in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2020 through mandated procurement programs, such as the BioMAT and BioRAM Programs. PG&E will seek permission from the Commission should PG&E intend to procure any incremental RPS volumes other than amounts separately mandated by the Commission during the time period covered by the 2019 RPS Plan.

4.A.4.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. Currently, PG&E is projecting a decrease in retail sales in 2020 and a continued, but modest decline through 2026 before growing slowly thereafter. These changes are driven by the increasing impacts of energy efficiency ("EE"), customer-sited generation, and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 7.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 7, 8, and 9, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement ("MMoP"); and (2) the need to account for PG&E's risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 7 and 8. Beyond these considerations, PG&E notes that future regulatory or legislative changes that are not currently included in PG&E's models could significantly impact PG&E's RPS need.

4.A.5. RPS Position Management and Sales of RPS Products

As described in Section 8.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next 10 years, in part due to dramatic recent and ongoing changes to PG&E's retail sales forecast. Accordingly, PG&E continues to seek authority in this 2019 RPS Plan to sell RPS volumes from its portfolio through short-term sales under the updated RPS Sales Framework in Appendix F and in Section 10 as described below.

4.B. Alignment with Load Curves

4.B.1. Anticipated Renewable Energy Technologies and Alignment of PG&E's Portfolio With Expected Load Curves and Durations

As described in previous RPS Plan filings, PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. Specifically, 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. Starting with its 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio.

4.B.2. Optimizing Cost, Value, and Risk for the Ratepayer

To mitigate RPS cost impacts, PG&E's fundamental strategy is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet compliance requirements; (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines, and (3) selling renewables in accordance with its framework described in Appendix F. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline and using the Bank to mitigate risks associated with load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13, the cost impacts of mandated procurement programs that focus on particular technologies or project sizes may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process where all technologies can compete to offer the best value to customers at the lowest cost. Finally, as described in Section 10, as part of its overall RPS position and management strategy, PG&E is proposing updates to its previously-approved framework for the sale of RPS volumes that returns revenue from sales to its customers.

4.B.3. Long-Term RPS Optimization Strategy

To optimize cost, value, and risks for customers, PG&E's long-term RPS optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to achieve the RPS compliance requirements. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's stochastically-optimized net short ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 7 and 8.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E is proposing to not hold a 2019 RPS procurement solicitation, future incremental procurement aimed at avoiding the need to procure extremely large volumes in any single year remains a component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes sales of surplus procurement that provide a value to customers. PG&E has developed a framework for sales, which was approved in previous iterations by the CPUC, and is provided in Appendix F.

The third component of the optimization strategy is effective use of the Bank. Under the existing RPS targets and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in 2029. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted] Section 8 below provides additional information regarding the use and size of PG&E's Bank.[26] PG&E notes that the size of its Bank may be impacted by the outcome of the PCIA OIR, and that any such change is not currently assumed in PG&E's RNS modeling.

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26 *Ibid.*

4.C. Responsiveness to Policies, Regulations, and Statutes

4.C.1. Adoption and Implementation of SB 350

On October 7, 2015, Governor Brown signed SB 350,[27] known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increased the RPS target from 33 percent in 2020 to 50 percent in 2030.

On June 29, 2017, the Commission adopted D.17-06-026, which implements new compliance requirements for the RPS program in response to changes made by SB 350. The Decision addresses the implementation of new rules for the use of long-term contracts in RPS compliance for all compliance periods beginning January 1, 2021. The new long-term requirement provides that, beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the RPS requirement of each compliance period must be from long term contracts. The Decision also: (1) implements new rules for applying excess procurement in one compliance period to later compliance periods beginning January 1, 2021; (2) provides direction for early compliance with the new long-term contract and excess procurement rules in the 2017-2020 compliance period; and (3) integrates changes made by SB 350 into the ongoing RPS compliance process.

In order to elect the early compliance option provided in SB 350, a retail seller must give notice of its election not later than 60 days from the effective date of D.17-06-026. PG&E gave notice on August 17, 2017, by letter addressed to the Director of Energy Division and served on the service list for R.15-02-020 of its election to comply early with the new long term and excess procurement requirements. Also in compliance with D.17-06-026, PG&E filed a motion on September 22, 2017 to update its RPS Procurement Plan to, among other things, reflect its election to comply early with the new long term and excess procurement requirements. Accordingly, the analysis set forth in the 2019 RPS Plan reflects PG&E's expectation that it will be subject to these

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[27] SB 350, Stats. 2015, Ch. 547 (De León).

new long term and excess banking rules beginning in the current 2017-2020 RPS compliance period.

On June 6, 2018, the Commission issued D.18-05-026, in which it implemented certain enforcement and penalty provisions contained in the SB 350 amendments to the RPS statute. Of particular relevance to this 2019 RPS Plan is the requirement in D.18-05-026 that each retail seller must annually demonstrate that transportation electrification is quantitatively accounted for in their RPS procurement plans. PG&E has described how it incorporated transportation electrification into its forecast of retail sales in Section 6.1.2.

4.C.2 Impact of GTSR Program

In 2013, SB 43[28] enacted the GTSR Program allowing PG&E customers to meet up to 100 percent of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment. In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." The most recent GTSR Annual Report for the program was filed with the Commission on March 15, 2019.

The GTSR Program impacts PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected as described below; and (2) retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply GTSR customers from an interim pool of existing RPS resources until new dedicated GTSR projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in a decrease in PG&E's RPS supply. However, there is also a possibility that PG&E's RPS supply could increase in the future if generation from GTSR-dedicated projects exceeds the demand of GTSR customers. In this case, those volumes procured for GTSR would then be added to

28 SB 43, Stats. 2013, Ch. 413 (Wolk).

PG&E's RPS portfolio, even if PG&E had no RPS need. PG&E has developed tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and GTSR Programs.

In conformance with D.15-01-051[29] and as described in the Joint Procurement Implementation Advice Letter, PG&E reports annually on the amount of generation transferred between the RPS and GTSR Programs in a report that is filed by September 1 each calendar year. In 2018, the sales under the Solar Choice Program was covered by the PG&E's Solar Choice Program-dedicated resources procured specifically for the Program. As more generation was procured under the program than was needed for Solar Choice customers in 2018, the excess solar generation will be transferred from the PG&E's Solar Choice Program to the RPS Program. PG&E anticipates a similar situation for 2019: the generation of the Solar Choice dedicated resources is likely to exceed the need of Solar Choice customers, and the excess solar generation will be transferred from the Solar Choice Program to the RPS Program.

On June 21, 2018, the Commission issued D.18-06-027 requiring the IOUs to implement two new Green Tariff programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs"). As approved in Res.E-4999 and in order to expedite program implementation for the new Disadvantaged Communities Green Tariff ("DAC-GT") program, PG&E will use the generation that exceeds customers' need from dedicated resources in the Solar Choice Program beginning in the first quarter of 2020. Of these dedicated Solar Choice resources, PG&E will utilize up to approximately 30 MW from facilities that are in the top 25% DACs. If necessary, and only after all 30 MW of the dedicated Solar Choice resources are exhausted, PG&E would use other qualifying RPS-eligible resources in its portfolio for the DAC-GT program. Generation utilized for the DAC-GT Program from any such resources would no longer be counted toward PG&E's RPS targets, which

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29 *See* D.15-01-051, p. 50.

could result in a decrease in the generation available to meet PG&E's bundled customer RPS requirements.[30] The resources will be utilized on an interim basis until dedicated new DAC-GT projects come online. Once new DAC-GT projects come online, generation may continue to be transferred from the Solar Choice Program to the RPS Program based on the need of Solar Choice customers. Use of Solar Choice or other RPS-eligible resources on an interim basis will be the only impact to PG&E's RNS position from the DAC-GT program as all costs will be recovered through GHG allowance proceeds, and if insufficient revenue is available, then through Public Purpose Program funds.

4.C.3 Implementation of Mandated Procurement Programs

Existing mandated procurement programs for RPS-eligible resources include BioMAT, ReMAT, and PV RAM. As described below, PG&E continues to seek to procure resources under BioMAT despite a demonstrated lack of need for additional RPS resources. ReMAT has been suspended and PG&E completed its PV RAM program in 2018.

4.C.3.1 BioMAT

On September 27, 2012, SB 1122[31] was passed, requiring California's IOUs to procure a total of 250 MW of new small-scale bioenergy projects that are 3 MW or less in size through the FIT Program. Other LSEs (including publicly-owned utilities ("POUs"), Electric Service Providers ("ESPs"), and CCAs) do not have this procurement obligation. Because all customers benefit equally from mandated procurement through BioMAT, PG&E believes that all customers should contribute equitably to their costs.

The total IOU BioMAT mandate is allocated into three technology categories with separate MW targets: (1) 110 MW of biogas from wastewater plants and green waste; (2) 90 MW of dairy and other agriculture bioenergy; and (3) 50 MW of forest

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30 PG&E will update its RNS following the dedication of any RPS resources currently included in the forecast of generation in the RNS to the DAC-GT program.

31 SB 1122, Stats. 2012, Ch. 612 (Rubio).

waste biomass. PG&E's SB 1122 BioMAT Program began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. PG&E has held bimonthly BioMAT auctions since February 2016.

On October 30, 2018, the Commission issued the BioMAT Program Review and Staff Proposal[32] to assess BioMAT program performance to date and recommend programmatic and procedural changes to simplify the procurement process, expand program participation, reduce ratepayer expenditures, and help achieve statewide goals. The proposal describes the Energy Division's key observations about program performance, sets a timeline for a program review, lays out a proposal for program changes, and seeks comment on the proposal to inform program workshops. The review will result in recommendations via a staff proposal for program changes to be considered as a part of a future RPS proceeding. The Joint IOUs filed comments in response to the Staff Proposal on December 7, 2018 and reply comments on January 4, 2019. Resulting workshops to discuss the program review have yet to be scheduled.

On a parallel track, the Commission issued D.18-11-004 instructing the IOUs to make changes to the Power Purchase Agreement ("PPA") and tariff to reflect the ability for bioenergy facilities that are interconnected to existing transmission lines (per Assembly Bill ("AB") 1923[33]) to be able to participate in the program. PG&E filed Advice Letter ("AL") 5454-E with these changes, which the Commission approved on January 18, 2019.

4.C.3.2 ReMAT

ReMAT was established in May 2012 when the Commission made several revisions to its FIT program. These changes included increasing the eligible project size from 1.5 MW to 3 MW, establishing a 750 MW program cap, and adopting the ReMAT pricing mechanism.[34] IOUs and POUs were allocated a share of the 750 MW

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32 See BioMAT Program Review and Staff Proposal, issued on October 30, 2018.

33 AB 1923, Stats. 2016, Ch. 663 (Wood).

34 *See* D.12-05-035.

program cap; other LSEs (ESPs and CCAs) do not have this procurement obligation. Because all customers benefit equally from the mandated procurement through ReMAT, PG&E believes that all customers should contribute equitably to their costs.

PG&E held bi-monthly auctions for ReMAT resources beginning on November 1, 2013. On December 6, 2017, the *Winding Creek Solar LLC v. Peevey* court decision[35] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of avoided cost and (2) the program MW cap violates PURPA's must-take obligation. On December 5, 2017, the Executive Director of the CPUC issued a letter ordering the three IOUs to refrain from signing new ReMAT contracts, to suspend holding any ReMAT program periods, and to stop accepting new applications for the program. As a result, all ReMAT program activity is currently on hold.

4.C.3.3 PV Program Procurement Through RAM (PV RAM)

In D.14-11-042, the Commission granted PG&E's petition to transfer approximately 200 MW from PG&E's PV Program to the Renewable Auction Mechanism 6 solicitation and two additional solicitations. On August 18, 2018, PG&E received approval in AL 5330-E for a PPA that met the final remaining procurement obligation pursuant to the original PV Program, thereby concluding the program.

4.C.4 Energy Storage

AB 2514,[36] signed into law in September 2010, requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514.

On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the

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35 Available at https://www.leagle.com/decision/infdco20171207935.

36 AB 2514, Stats. 2010, Ch. 469 (Skinner).

decision, PG&E completed its 2014 and 2016 Energy Storage RFOs. On December 1, 2017, PG&E submitted six executed agreements that resulted from the 2016 Energy Storage RFO for CPUC approval.[37]

In January 2018, the CPUC issued Res.E-4909, authorizing PG&E to launch an accelerated solicitation for energy storage projects to contribute to reliability needs for three specified local subareas in the northern central valley and in an area spanning Silicon Valley to the central coast (Pease, Bogue, and South Bay – Moss Landing local sub-areas). PG&E issued its Local Sub-Area Solicitation in February 2018 and received offers from numerous participants. PG&E ultimately selected and submitted for approval four projects to come online in 2020 to be located within the South Bay – Moss Landing local sub-area: one offer for a 182.5 MW utility-owned project and three offers for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage.[38] The Commission approved these projects in Res.E-4949, including allowing them to count toward PG&E's AB 2514 targets. These projects are also expected to help increase the overall flexibility of the grid to integrate high levels of wind and solar generation.

PG&E did not hold a 2018 Energy Storage RFO because PG&E's past storage procurement was within the 2018 AB 2514 target established by the Commission. Further detail on PG&E's energy storage procurement can be found in its most recent biennial Energy Storage Plan.[39]

AB 2868,[40] signed into law in September 2016, required that the IOUs file applications for programs and investments to accelerate widespread deployment of

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37 Application of Pacific Gas and Electric Company (U 39-E) for Approval of Agreements Resulting from Its 2016-2017 Energy Storage Solicitation and Related Cost Recovery, Application ("A.")17-12-003.

38 Advice 5322-E, Energy Storage Contracts Resulting from PG&E's Local sub-area RFO Per Res.E-4909, submitted June 29, 2018.

39 Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018, A.18-03-001.

40 AB 2868, Stats. 2016, Ch. 681 (Gatto).

distributed energy storage systems. In March 2018, PG&E filed its proposal with the Commission to deploy 166.66 MW of distributed energy storage in compliance with AB 2868.[41] On February 26, 2019, the Commission issued a Proposed Decision approving PG&E's proposal for a behind the meter thermal energy storage program that would deploy up to 5 MW of controllable water heaters at customers sites by 2024, prioritizing low-income customers. The goals of the program are to shift water heating load from peak to off-peak hours and provide benefits to customers through lower energy bills and a pay for performance incentive. A final decision on PG&E's AB 2868 proposal was pending at the Commission as of June 21, 2019.

In the following discussion, PG&E addresses how its acquisition and use of energy storage systems is designed to achieve the purposes set forth in Pub. Util. Code Section 2837:

(a) Integrate intermittent generation from eligible renewable energy resources into the reliable operation of the transmission and distribution grid.

PG&E's energy storage portfolio provides renewable energy resource integration benefits by virtue of the storage systems' participation in the wholesale energy and capacity markets. The energy storage procured by PG&E in the 2018 Energy Storage Solicitation and in the Local Sub-Area Solicitation includes contracts for Resource Adequacy ("RA"), which requires the energy storage resources to be bid into the wholesale energy market. Accordingly, the CAISO will be able to dispatch these resources when needed and economically desirable in the Day-Ahead and Real-time Markets to balance demand and a diverse supply portfolio for the reliable operation of the grid.

(b) Allow intermittent generation from eligible renewable energy resources to operate at or near full capacity.

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41 Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018, A.18-03-001.

For the same reasons described in (a), above, PG&E's energy storage portfolio can reduce the need for renewable energy curtailments by virtue of the storage resources' participation in the CAISO market.

(c) Reduce the need for new fossil-fuel powered peaking generation facilities by using stored electricity to meet peak demand.

PG&E's energy storage portfolio can reduce the need for new fossil-fuel peaking generation by virtue of the storage resources' participation in the CAISO market and inclusion in the Commission's IRP process. The energy storage procured by PG&E includes contracts for RA, which requires the energy storage resources to be bid into the CAISO market in compliance with their Must Offer Obligations. PG&E's energy storage resources are therefore included in the Commission's and CAISO's forecasts of resources available to meet peak system load and reduce the need for new marginal resources to be built.

(d) Reduce purchases of electricity generation sources with higher emissions of GHGs.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can reduce the need for generation sources with higher GHG emissions by virtue of the storage resources' participation in the CAISO market.

In the case of PG&E's Local Sub-Area procurement, these energy storage systems are expected to directly reduce GHG emissions. This procurement was directed by the Commission specifically to obviate the need for three natural gas plants to remain online for local reliability in the Moss Landing local sub-area.[42]

(e) Eliminate or reduce transmission and distribution losses, including increased losses during periods of congestion on the grid.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can reduce losses on the grid by virtue of the storage resources' participation in the CAISO market.

(f) Reduce the demand for electricity during peak periods and achieve permanent load-shifting by using thermal storage to meet air-conditioning needs.

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42 *See* Res.E-4909.

PG&E's energy storage portfolio does not currently include thermal storage to meet air-conditioning needs.

(g) Avoid or delay investments in transmission and distribution system upgrades.

PG&E's energy storage portfolio includes the Llagas Energy Storage project, which is a 20 MW distribution deferral project slated to come online in 2021. The deployment of the Llagas lithium ion battery storage system was designed to defer the need for upgrades at PG&E's Llagas substation.

(h) Use energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can provide ancillary services by virtue of the storage resources' participation in the CAISO market.

4.D. Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including 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 the Net Market Value ("NMV") valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity may have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in the procurement of different technology types. Such considerations have resulted in a diverse set of resources that make up PG&E's portfolio over the ten-year planning horizon.[43]

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. PG&E believes, as a general principle, that less restrictive procurement structures, in contrast to mandated programs, will provide the best opportunity to maximize value for its customers. Less restrictive procurement structures also will enable proper responses to changing market conditions and more competition between resources. PG&E further believes that geographic or technology-specific mandates add additional costs to RPS procurement.

4.E. Lessons Learned

Please see Section 10.A.5, below, where lessons learned from PG&E's portfolio optimization activities over the past year are discussed in the context of its recent and ongoing RPS sales solicitations.

4.F. Conformance with IRP

Overall, this PG&E 2019 RPS Plan conforms to and is consistent with the renewable procurement findings from PG&E's 2018 IRP filed in R.16-02-007 on August 1, 2018.[44] As stated in PG&E's 2018 IRP filing, under both Commission's Conforming and PG&E's Preferred planning scenarios, PG&E's IRP found no incremental renewable procurement need beyond PG&E's planned procurements to

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43 See PG&E's 2018 IRP filed on August 1, 2018 in CPUC R.16-02-007 Table 11 (p. 49) for a quantitative breakdown of its portfolio by technology type.

44 See PG&E's 2018 IRP filed on August 1, 2018 in CPUC R.16-02-007; Small differences between the plans are largely driven by the latest updates on the forecasted demand, which does not trigger any incremental procurement need.

meet its obligations and support various existing state mandates and programs through the planning year 2030. Given its lack of procurement need, both PG&E's 2018 IRP and its 2019 RPS Plan conform to the Commission's recently adopted the Preferred System Portfolio in D.19-04-040.[45]

5. Project Development Status Update

PG&E, Southern California Edison Company, and San Diego Gas & Electric Company file monthly RPS Database submissions with the CPUC. These monthly submissions contain a larger collection of data on each RPS project than previously provided in the IOUs' Project Development Status Reports. Project development status updates for RPS contracts can now be obtained from the publicly available data published on the Commission's website at http://cpuc.ca.gov/RPS_Reports_Data.

6. Potential Compliance Delays

This Section addresses factors, including those identified in the RPS statute, that may impact PG&E's ability to comply with its near-term RPS requirements or its need for a statutory waiver of those requirements.[46] While in general PG&E does not currently foresee obstacles to achieving compliance with existing RPS requirements, market conditions and changes in law and regulatory requirements could change this outlook in the future.

6.1 Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite PG&E's current expectation that it will be able to comply on time with existing RPS requirements, significant market, operational, or regulatory changes could

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45 That is, PG&E's planned RPS portfolio captures its portion of the existing and planned resources modeled in the Preferred System Portfolio.

46 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Pub. Util. Code § 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

impact that assessment. This section describes briefly some of the risks and the steps PG&E is taking to mitigate these risks.

6.1.1 Curtailment of RPS Generating Resources

As discussed in more detail in Section 12, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may reduce the RPS energy available for compliance. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 7.2.

6.1.2 Transportation Electrification

PG&E's retail sales forecast is adjusted for expected load increases due to electric vehicle ("EV") adoption. PG&E's EV energy demand and capacity forecast in the 2019 RPS Plan cycle includes medium-duty and heavy-duty vehicle segments, in addition to the light-duty segment. In order to consider the impact of EVs on PG&E's annual load, PG&E developed an internal probabilistic assessment of EV penetration, leveraging: (1) aggregated EV registration data available through December 2018; (2) policy goals declared through December 2018 as well as modeling of compliance for existing policy; (3) EV adoption scenarios developed by ICF International, Inc. in the California Electric Transportation Coalition's Transportation Electrification Assessment; and (4) inputs describing typical EV electricity consumption and charging behavior. PG&E did not directly leverage the California Energy Commission's ("CEC") 2017 Integrated Energy Policy Report ("IEPR") transportation electricity demand forecast in developing its EV forecast. PG&E and the CEC use two fundamentally different modelling approaches, with PG&E using a policy-driven adoption model (top down) and the CEC using a consumer choice model (bottom-up). Thus, modeling assumptions are not easily transferable between the two approaches. However, PG&E did compare its EV forecast results against the CEC's reference scenario and found PG&E's forecast to be about 35% higher than the CEC forecast for PG&E's service territory in 2030. The results derive from PG&E's higher adoption forecast which considers approximately 2 million light-duty EVs by 2030, whereas the CEC's forecast considers approximately 1.5 million light-duty EVs in PG&E's territory. In addition to using different modeling approaches, the CEC did not update its medium-duty and heavy-duty vehicle forecast in its 2018 IEPR Update (November 2018). PG&E and the CEC use different input assumptions that may impact the forecast results. For example, PG&E's EV forecast assumes growth in the rideshare market and 100% electrification of transit buses by 2040, whereas the CEC IEPR forecast does not.

6.1.3 Risk-Adjusted Analysis

As more fully described in the following section, PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. PG&E's experience with RPS procurement is that developers often experience difficulties managing some of the development issues described above. As described in Section 9, PG&E's expected RPS need calculation incorporates a MMoP to account for some anticipated project failure and delays in PG&E's existing portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 60 percent RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

7. Risk Assessment

Dynamic risks, such as the factors discussed in Section 6 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. As described elsewhere in this RPS Plan, PG&E is currently well-positioned to meet its RPS compliance requirements and its risk of non-compliance is low. Nevertheless, to account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; 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 MMoP, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[47] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[48]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 7.1 identifies the three risks accounted for in PG&E's deterministic model. Section 7.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 7.3 describes how the risks described in the first two sections are incorporated into both models, including details

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47 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

48 PG&E has also developed a framework to assess whether to hold or sell RPS volumes, included in Appendix F.

about how each model operates and the additional boundaries each sets on the risks. Section 7.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 8 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices A.1 and A.2. Section 9 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

7.1 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.
2) Project Failure: the determination of whether or not 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 7-1
DETERMINISTIC MODEL RISKS

Risk	Methodology	Applies to
Standard Generation Variability	• For non-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 Irrigation District and Water Agency ("ID&WA") 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

7.1.1 Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non-QF; non-hydro QFs; and hydro QF projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, normalized for average water year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. The UOG and ID&WA forecast are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix C.

7.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E

categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0 percent deliveries) and ON (represented with 100 percent deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online or none of the generation comes online.

1) **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":
    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.);
    - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data);
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization;
    - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability;
    - Whether a PPA amendment has been executed but has not yet received regulatory approval; and
    - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as “Closely Watched.”[49] PG&E does not currently have any in-development projects categorized as “OFF” in its deterministic model.

2) **ON** – Projects in all other categories are assumed to deliver 100 percent of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of “ON” projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of “ON” projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of “ON” projects represents executed and future contracts from Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes within a reasonable timeline.

7.1.3 Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

7.2 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.

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49 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

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 Uncertainty: 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 Participating Transmission Owner ("PTO")-ordered curtailment; and
4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

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 7-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 7-2
CATEGORIZATION OF IMPACTS ON RPS POSITION

	Impact	Categorization
Higher Impact on RPS Position	**1. Retail Sales Uncertainty:** Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
	2. Curtailment: Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
	3. 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	**4. Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

7.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, EVs, and distributed generation.

For DA, additional load loss based on DA expansion required by SB 237 has been incorporated into PG&E's stochastic model. Specifically, PG&E assumes that the 4,000 GWh DA expansion ordered occurs in January 2020.[50] PG&E relied on its Fall 2018 DA waitlist to estimate the proportion of customers departing from bundled service versus CCA service. PG&E assumes its service territory will be allocated 38 percent of the 4,000 GWh. PG&E forecasts a total of 11,175 GWh of DA load in its service territory in 2020, including both new DA load under SB 237 and existing DA load under SB 695. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting additional increases in DA beyond those provided for in SB 237.

Load loss due to CCA departure is modeled in two categories: (1) existing CCAs that have already departed or will depart and serve load by 2020; and (2) potential CCAs that have expressed interest in forming based on publicly available information. For existing CCAs, PG&E follows a meet and confer process to communicate with CCAs regarding their load forecasts. PG&E receives year-ahead load, peak demand, and customer forecasts from the CCAs, and forecasts future years' volumes using PG&E's forecasted total system load growth rate, which accounts for economic/demographic factors, weather, and growth of DER technologies such as solar PV, EE. For potential CCAs, PG&E has developed a stochastic (probabilistic) approach

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50 Modeling and modeling assumptions were completed prior to D.19-05-043, which delayed DA expansion to January 2021.

to forecast CCA load departure. This model uses publicly available information—including feasibility studies, implementation plans, board meetings, and news articles—to assign probabilities to all communities considering CCA formation. Similar probabilities are applied to communities with the same CCA maturity levels. The model uses 2018 annual energy load as the benchmark, and PG&E applies system load growth percentages to approximate future load growth or decline.

7.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from 1985-2012, wind generation data from 1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]. The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is uncorrelated among technologies.

7.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered, or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). Curtailment forecasts ramp from a historical level of [redacted]

[redacted][51] These modeling assumptions will not necessarily reflect the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 12 for more information regarding curtailment.

7.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted] For example, a project scheduled to come online in five years or more is assumed to have a [redacted] percent chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower.

7.2.5 Comparison of Model Assumptions

Table 7-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure,

51 [redacted]

RPS generation, and curtailment. Section 8 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 7-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[(a)]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2017-2018 IRP for later years (Appendix A.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix A.2).	Distribution based on most recent (2019) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "OFF" projects with high likelihood of failure per criteria. "ON" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted] This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
3) RPS Generation Variability	Non-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, UOG and ID&WA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2017 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

(a) These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

7.3 How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

7.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives; (b) inputs; and (c) constraints of the model:
    (a) The objective is to minimize procurement cost.
    (b) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes)[52] in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] annually.
    (c) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted] less than [redacted] less than [redacted] and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

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52 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not allow for price arbitrage through sales of RPS generation in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2020 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this 2019 RPS Plan.

7.5 Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the existing RPS targets are shown in Row La of PG&E's Alternate RNS in Appendix A.2.

The results of both the deterministic and stochastic models are discussed further in Section 8 and MMoP is addressed in Section 9.

8. Quantitative Information

As discussed in Section 7, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix A. Appendix A.1 presents the RNS in the form required by the ALJ's Ruling on RNS issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendix A.2 is a modified version of Appendix A.1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its Bank size and PG&E's analysis of the minimum bank needed.

8.1 Deterministic Model Results

Results from the deterministic model under a 60 percent by 2030 RPS target and 60 percent RPS annually thereafter are shown as the physical net short in Row Ga of Appendices A.1 and A.2. Appendix A.1 provides a physical net short calculation using PG&E's April 2019 internal Bundled Retail Sales Forecast for years 2019-2023 and the IRP sales forecast for 2024-2036,[53] while Appendix A.2 relies exclusively on PG&E's April 2019 internal Bundled Retail Sales Forecast. Following the methodology described in Section 7.1, PG&E currently estimates a long-term volumetric success rate of 100 percent for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fb of Appendix A.2. 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 6, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix A.2 depict PG&E's expected

[53] Bundled sales forecast used for 2024-2036 is from PG&E's approved 2018 LSE IRP filed for the 2017-2018 IRP Cycle.

compliance position using the current expected need scenario before application of the Bank.

8.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter. Because PG&E uses its stochastic model and internal Bundled Retail Sales Forecast to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix A.2 for the 60 percent RPS target. Appendix A.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendix A.2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

Under the existing RPS targets, PG&E is well-positioned to meet its compliance period requirements through the fifth compliance period (2025-2027). As shown in Row Lb of Appendix A.2, the stochastic model shows a third compliance period RPS position of [redacted], a fourth compliance period RPS position of [redacted], a fifth compliance period RPS position of [redacted], and a sixth compliance period RPS position of [redacted]. Appendix A.2 also shows a physical net short of approximately [redacted] beginning in 2029 (Row Ib plus Row Gd).

For both tables, Row Lb includes both PG&E's executed and generic RPS sales volumes shown in Rows Fd and Ib, respectively.[54] The annual RPS sales volume forecast assumption is based on RPS sales executed in 2018 as well as the proposed

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54 Total forecasted RPS sales in 2019 and 2020 are based on executed sale agreements through May 31, 2019.

sales framework requested in this 2019 RPS Plan and is included in PG&E's forecast for RPS position planning purposes. Based on the sales framework approved in the 2018 RPS Plan, the forecasted RPS sales volumes could potentially increase an additional [redacted] to what is currently forecasted, which would result in the first year of incremental procurement need being [redacted]. In the event that the total RPS generation less RPS sales falls below the RPS Compliance requirement in any given year, PG&E would still meet its RPS Compliance requirement through the use of previously accumulated RPS Bank (see Row J in Appendix A.2).

8.2.1 SONS to Meet Non-Compliance Risk Target

To evaluate possible procurement strategies, PG&E selected the following non-compliance risk targets for each future compliance period: [redacted]

Figure 8-1 shows the model's forecasted procurement need and resulting Bank usage under the 60 percent RPS by 2030 target and 60 percent RPS annually thereafter. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in 2029, the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 7. Appendix A.2 provides the detailed results. Annual forecasted Bank usage is shown as the sum of Rows Gd and Ib of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as after 2033. Should PG&E engage in additional RPS sales, this may result in an earlier procurement need year and its position will be updated in subsequent RPS Plans.

FIGURE 8-1
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED BANK USAGE AND SONS

[redacted]

Note: Bank usage values have been rounded to the nearest 100 GWh.

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

8.2.2 Bank Size Forecasts and Results

Figure 8-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2033. PG&E's total Bank size as of the end of the second compliance period was approximately 12,800 GWh. The stochastic model's results currently project PG&E's Bank size to increase in the second through fifth compliance periods and [redacted]

[redacted] (as shown in Figure 8-2, as well as in Appendix A.2, Row J). As described in Section 8.2 above, the forecasted 2033 Bank total assumes a total of 50,500 GWh of RPS sales from 2019-2028.

FIGURE 8-2
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED CUMULATIVE BANK

[redacted]

Note 1: Bank values in CP1 and CP2 are based on the total 'Excess Procurement Bank' in PG&E's RPS Compliance Report.
Note 2: Bank values in CP3 and beyond have been rounded to the nearest 100 GWh.

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

8.2.3 Minimum Bank Size

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[55] The difference between delivery and target can be thought of as the potential “need” (if negative) or “surplus” (if positive) that PG&E has in any one year.

Figure 8-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]

Based on current model assumptions and inputs, Figure 8-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level.

FIGURE 8-3
CONFIDENTIAL
DISTRIBUTION OF DELIVERY MINUS TARGET FROM 2026 THROUGH 2030 UNDER A 60 PERCENT RPS TARGET

[redacted]

As stated in Section 8.2.2, the stochastic model’s results show PG&E’s forecasted [redacted]. PG&E’s strategy is to maintain an

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55 [redacted]

adequate Bank in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs.

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 8-3 illustrates.

8.3 Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this 2019 RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales. PG&E will update its RNS in the future as it executes any such sale agreements.

9. Minimum Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory MMoP to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 60 percent RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these procurement margin measures and how each is incorporated into PG&E's quantitative analysis of its RPS need.

9.A. MMoP Methodology and Inputs

Please generally see Section 7, above, for a discussion of PG&E's modeling methodology and inputs.

9.B. MMoP Scenarios

9.B.1. Statutory MMoP

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[56] PG&E's reasonableness in incorporating this statutory MMoP into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[57]

As described in more detail in Section 7, 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). PG&E considers this deterministic result to be its current statutory margin of procurement.[58] However, as discussed in Sections 7 and 8, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and

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56 Pub. Util. Code § 399.13(a)(4)(D).

57 *Id.*, § 399.15(b)(5)(B)(iii).

58 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums.

uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

9.B.2. VMOP

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory MMoP.[59] As discussed further in Sections 7 and 8, 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.

While PG&E's current optimization strategy projects the use of a portion of PG&E's projected Bank to meet compliance requirements in 2029 and beyond, PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. Using the Bank as its VMOP will reduce non-compliance risk while also helping to avoid long-term over-compliance above the existing RPS targets and thus reducing long-term costs of the RPS Program, which could result if PG&E held both a Bank and an additional VMOP. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 7 and 8.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

10. Bid Solicitation Protocol, Including Least-Cost Best-Fit Methodologies

As previously described, PG&E is well positioned to meet its RPS targets until after 2033. As a result, PG&E proposes to not hold a 2019 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2019 and 2020

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[59] Pub. Util. Code § 399.13(a)(4)(D).

through any other Commission-mandated programs, such as the BioMAT program. PG&E will seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2019 RPS Plan, except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2019 RPS Plan a solicitation protocol for procuring additional RPS resources. PG&E's proposal to conduct one or more RPS sales solicitations during this RPS Plan cycle are described more fully below.

10.A. Solicitation Protocols for Renewable Sales

10.A.1. Updates to the RPS Sales Framework

The goal of PG&E's RPS Sales Framework is to prudently manage its portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. PG&E will continue to seek and evaluate opportunities to execute short-term contracts to sell RPS-eligible products from its portfolio under the RPS Sales Framework. These short-term sales would be for volumes to be delivered in the years 2020-2021 in order to preserve optionality while resolving Phase 2 of the PCIA OIR.

The objective of PG&E's updated Sales Framework is to return to a balanced RPS position in a timely manner, and mitigate price risk to customers, by adhering to the following principles:

- Compliance: Ensure PG&E can maintain compliance with RPS requirements;
- Value for Customers: Ensure value for customers; and
- Flexibility: Adapt to a fluctuating market and policy landscape through annual revisions in the RPS Plan filing.

In comparison to the approved 2018 RPS Sales Framework, PG&E refines its framework to [redacted]

10.A.2. Implications of the Updated Sales Framework

A key aspect of the updated RPS Sales Framework is that it may result in volumes of sales [redacted]

[redacted][60]

10.A.3. Implementation of the RPS Sales Framework

Based on current inputs to the RPS Sales Framework described in Appendix F, PG&E will target issuing three, with a minimum of two, solicitations for the sale of bankable, bundled renewable generation and RECs in 2020.[61] PG&E anticipates selling short-term products, meaning contracts of two years or less in duration, under the Framework.

PG&E intends to execute sales through PG&E-initiated solicitations. Confidential Appendix E contains PG&E's sales solicitation protocol and pro forma sales agreement. The sales solicitation protocol and pro forma sales agreement are largely unchanged from the 2019 Bundled RPS Energy Sale Short Form Confirm approved in the 2018 RPS Plan cycle. PG&E anticipates minimal negotiations with buyers with respect to the form agreement.

PG&E will file short-term sales agreements resulting from a solicitation that are negotiated based upon the pro forma sales agreement, with any necessary modifications, as Tier 1 Advice Letters for Commission approval.[62]

10.A.4. 2018 RPS Sales – Lessons Learned

While PG&E has executed a limited number of agreements for the sale of RPS volumes from PG&E's portfolio, PG&E's second such solicitation (the "2018 RPS Sales Solicitation") was issued in 2018. Upon completion of the 2018 RPS Sales Solicitation, PG&E surveyed market participants to solicit feedback on how to improve the process

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60 PG&E cannot guarantee that its RPS position will be above the target given the uncertainty in retail sales and forecasted generation. If PG&E did sell its excess and then its actual position was shorter than its compliance target, PG&E has sufficient banked volumes to ensure it can comply with the RPS targets.

61 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations will depend on the outcome of prior solicitations and/or changes to PG&E's RPS position.

62 D.17-12-007, OP 7; D.14-11-042, p. 77.

and to understand why certain market participants did not bid. In addition, PG&E received feedback from the Independent Evaluator assigned to monitor the solicitation and resulting negotiations.

As a result, PG&E has identified a number of best practices to incorporate in future solicitations.

10.A.4.1 Desire for PCC Certainty

Counterparties consistently sought contract language certifying that the bundled RPS volumes to be sold and purchased would be deemed to be PCC 1 by the Commission. PG&E agreed to represent that the resources used for the sale, if retired for compliance by PG&E, would be expected to meet the definition of PCC 1 as described in Pub. Util. Code Section 399.16(b)(1). However, PG&E was unable to provide the certification that buyers requested because any such determination is outside of PG&E's control. The Commission determines the applicable PCC category of RPS products used by retail sellers to meet RPS compliance requirements in a process that is independent from, and later in time from, the process to review and approve a contract executed by PG&E for the sale of RPS volumes. Given the request presented to PG&E, PG&E believes that it would facilitate the sale of bundled RPS volumes if the Commission determined the PCC of the products as to the purchasing entity in connection with the Advice Letter approval process to review the sales agreement.

10.A.4.2 Product Term

In 2018, PG&E sought sales with energy deliveries over multiple years rather than in a single year as it had previously solicited in 2017. Buyers were receptive to the extended term of energy deliveries in the 2018 RPS Sales Solicitation and conveyed their preference sales for multiple years rather than single years. In 2019, PG&E will continue to solicit sales with deliveries across multiple years.

10.A.4.3 Timing and Timeline of Solicitation

[redacted]

To address these concerns PG&E will conduct future solicitations in a very streamlined manner, and intends to target issuing three, with a minimum of two, solicitations during calendar year 2020. PG&E aims to issue its first 2020 RPS Sales Solicitation shortly after the 2019 RPS Plan has received final approval from the CPUC.

10.A.4.4 Execution Process

In future short-term sales solicitations, PG&E will identify in advance which areas of the sales agreement are eligible to be discussed. Using the standardized form of agreement developed in 2018, PG&E engaged in limited discussions with buyers in 2019. [redacted] As a result, PG&E expects discussions with buyers on the short-term sales agreement to be minimal in 2020 to streamline the execution process.

10.B. Bid Selection Protocols

PG&E has included in Section 10.A, above, a description of the Framework that PG&E proposes to use to evaluate sales from its existing RPS portfolio. The Framework itself is included in Appendix F. The Commission has approved a similar framework in prior RPS Plans. PG&E has included a solicitation protocol and pro forma sales agreement as Appendix E to this 2019 RPS Plan. The pro forma sales agreement is based on the Edison Electric Institute (“EEI”) Master Agreement and is consistent with the form agreement that PG&E used in its 2019 RPS Sales Solicitation. The protocol and form of sales agreement incorporate lessons learned from the 2019 RPS Sales Solicitation, as previously described in this section.

PG&E anticipates that minimal negotiations will be needed with respect to the form sales agreement and proposes filing any executed short-term sales agreements by a Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[63] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under two years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to occur in 2020.

10.C. LCBF Criteria

Although PG&E is not planning for a RPS procurement solicitation, PG&E recognizes that the most recent detailed description of its LCBF methodology, including the NMV and PAV methodologies, has continued to be used as a reference for procurement valuation for mandated programs. Accordingly, as part of this 2019 RPS Plan, PG&E is providing an update to the LCBF methodology approved in its 2018 RPS planning cycle to better reflect current market and portfolio conditions. PG&E's updates to the quantitative LCBF Protocol are minor, and are solely focused on refinements to calculating congestion and losses, and updating those results. The revised version of PG&E's detailed explanation of its LCBF methodology is included as Appendix G to this 2019 RPS Plan. A redline showing this revised version of the LCBF methodology against the last Commission-approved version (from PG&E's 2018 RPS Plan) is provided for convenience at Appendix K to this 2019 RPS Plan.

10.C.1. Informational-Only Time of Delivery Factors

PG&E historically set the TOD factors in its RPS procurement contracts based on expected (internally forecasted) hourly prices, load forecasts, and capacity values.

In PG&E's review of the TOD factors for the 2018 RPS Plan, PG&E determined that it has been increasingly difficult to accurately forecast TOD preferences within even

[63] D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

the next decade, let alone for the duration of a typical RPS PPA (e.g., 20 years), given California's quickly evolving energy mix, policies, and markets.

PG&E determined that TOD factors in a long-term PPA are unlikely to reflect system need over the entire life of the PPA. In fact, changes in the State's net load over time could result in TOD factors incentivizing production under a PPA at times in which the PPA contributes to overgeneration problems, rather than helps to solve them.

Given the reasons outlined above, PG&E eliminated TOD factors for any new RPS procurement contracts that may be executed in the future, including in new contracts to be executed in existing mandatory procurement programs, such as BioMAT. However, pursuant to D.19-02-007, PG&E calculated TODs for informational purposes only, in order to communicate to developers when energy deliveries might be more valuable to the system and allow developers to respond with optimized project designs and bids.[64] PG&E's proposed informational-only TOD factors were served on the R.18-07-003 service list on May 29, 2019, in compliance with D.19-02-007.[65]

Subsequently, the Commission issued D.19-42-042, ordering that informational-only TOD factors be included in PG&E's final 2019 RPS plan based on the most recent inputs available.[66] Appendix J contains updated informational-only TOD factors based on Marginal Energy Costs ("MEC") contained in workpapers developed in Phase II of PG&E's 2020 General Rate Case (A. 19-11-019), and are subject to Commission approval. The MEC workpapers are proprietary because MEC workpapers contain complex models developed by PG&E. In contrast, informational-only TOD factors provided as Appendix J are publicly available because those factors are based on aggregated data. Updated informational-only TOD factors are also available online under "Renewables Portfolio Standard (RPS)" at http://www.pge.com/rfo. PG&E

64 D.19-02-007, OP 16.

65 *Id.,* OP 17.

66 D.19-42-042, OP 26.

anticipates that any updates to informational-only TOD factors will be posted to that website.

10.C.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include “the employment growth associated with the construction and operation of eligible renewable energy resources.”[67]

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E’s LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E’s assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California for the proposed project. This information was required from bidders in PG&E’s 2014 RPS RFO.[68]

10.C.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given “to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.”[69]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new

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67 Pub. Util. Code § 393.13(a)(4)(A)(iv).

68 Appendix J2 to 2014 RPS RFO Protocol.

69 Pub. Util. Code § 399.13(a)(7).

selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from participants similar to what was required in the 2014 RPS RFO.[70] PG&E asked participants to respond to the following questions on this topic:

Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the participant is encouraged to describe in its offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:

- Projected hires from adjacent community (number and type of jobs),
- Duration of work (during construction and operation phases),
- Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
- Emissions reduction – Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
  - If "yes", provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).
  - If "No", why not?

11. Consideration of Price Adjustment Mechanisms

The 2019 RPS Plan Ruling requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index ("CPI"),

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[70] Appendix J2 to 2014 RPS RFO Protocol.

price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[71]

In this 2019 RPS Plan, PG&E is proposing to not hold an RPS procurement solicitation in this 2019 RPS Plan cycle. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. 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.[72] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined, agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[73]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may

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71 2019 RPS Plan Ruling, p. 19.

72 Pub. Util. Code § 399.11(b)(5).

73 D.11-04-030, pp. 33-34.

not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource and is instead linked to increases in prices of oil and natural gas, food, medical care, and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

12. Curtailment Frequency, Cost, and Forecasting

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Plans how "expected economic curtailment affects their RPS procurement."[74] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including periodic reporting to the Procurement Review Group.[75]

In response to the specific requests for information related to curtailment included in the 2019 RPS Plan Ruling, PG&E provides the following information:

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

As the CAISO has stated:

> A swift rise in California's renewable energy capacity, especially solar generation, is the main driver behind the growing occurrence of oversupply.... Currently, the ISO's most effective tool for managing oversupply is to "curtail" renewable resources. That means plant generation is scaled back when there is insufficient demand to consume production.... Curtailments can occur in three ways: economic curtailment, when the market finds a home for low-priced or negative-priced energy; self-scheduled cuts, which reduce generation from self-scheduled bids; and exceptional dispatch, when the ISO orders generators to turn down output."[76]

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74 D.14-11-042, p. 45.

75 *Id.*, pp. 42-43.

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

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

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

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

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

To the extent that it is contractually and operationally able to do so, PG&E has bid RPS-eligible resources in its portfolio into the CAISO markets. When there are negative prices in the CAISO market, these resources may be economically curtailed given their bid price. Economic-based curtailments awarded during negative price periods have created direct and indirect benefits for PG&E's customers and the CAISO.

PG&E started Day-Ahead economic bidding for RPS-eligible resources in February 2014 and subsequently initiated Real-Time economic bidding in September 2014. PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. [redacted]

[redacted] PG&E provided more detail concerning its RPS bidding strategy in its Bundled Procurement Plan[77] which was approved by the Commission in D.15-10-031.

While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods, and also improving CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events. The overall trends in both the frequency and magnitude of negative prices in recent years suggests that the CAISO is able to generally balance supply and demand using economic curtailment rather than administratively curtailing generation.

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

There were no incidences of overgeneration, as this term is defined by the CAISO, in 2018. The ability for the CAISO to control renewable output through economic curtailment is a key tool in preventing overgeneration.

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

Regarding longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. For a discussion of forecasted curtailment levels please see Section 7.2.3. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

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 oversupply events.

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77 *See* PG&E 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

13. Cost Quantification

This section summarizes actual and forecasted RPS generation costs. Table 2 outlines the information utilities are required to include in the Cost Quantification Template made available by the Commission on its website. The resulting data are shown in Tables 1 through 4 of Appendix B. Page 1 of Appendix B outlines the methodology for calculating the costs and generation.

TABLE 2
RPS PROCUREMENT AND SALES INFORMATION RELATED TO COST QUANTIFICATION

Row	Item	Description
1.	Actual Direct Expenditures and Revenue – per year	Total dollars expended and received for all REC transactions for every year from 2003 to present year. Figures shall be reported by resource and technology type and reported for each year.
2.	Actual REC Procurement (MWh) – per year	Total REC procurement for every year from 2003 to present year, including any REC sales. Amounts shall be reported by resource and technology type and reported for each year.
3.	Forecast Direct Expenditures and Revenue – per year	Total forecasted dollars expended and received for all REC transactions to date (and approved to date for the utilities). Forecasts Direct Expenditures shall be reported by resource and technology type and reported for each year from 2018-2030.
4.	Forecast REC Procurement (MWh) – per year	Total forecasted REC procurement to date (and approved to date for the utilities), including any planned REC sales. Forecasts shall be reported by resource and technology type and reported for each year.
5.	I Annual Average RPS rates ($/kWh)	Total actual and forecasted annual utility RPS generation and procurement costs divided by bundled load from 2003-2030.

13.1 RPS Cost Impacts

Appendix B quantifies the cost of RPS-eligible procurement—both historical (2003-2018) and forecast (2019-2030). PG&E's annual RPS-eligible procurement and generation costs rose sharply from 2003 through 2015, from $523 million to more than $2.4 billion in those years, respectively. However, since 2015 PG&E's RPS-eligible procurement and generation costs have stabilized around $2.4 billion per year. On a forward-looking basis (2019-2030), PG&E's RPS portfolio costs are expected to average about $2.35 billion. The somewhat lower costs over the first part of forecast period are primarily due to greater anticipated RPS sales revenue.

On the other hand, the average RPS rates shown in Appendix B rise steadily through the first half of the forecast period and then decline gradually through 2030. This is largely a result of the underlying bundled load forecast which declines in the first part of the forecast due continued anticipated CCA growth and then gradually increases due to anticipated increases in electric vehicle usage. Because the rates calculated in the Cost Quantification Template do not reflect allocated costs to departed load (e.g., DA and CCA customers), these illustrative rates will overestimate the actual impacts on forecasted bundled rates.

13.2 Cost Impacts Due to Mandated Programs

The cost impacts of mandated procurement programs that focus on particular technologies or project size have comprised an increasing share of PG&E's incremental procurement in recent years, to the extent that incremental procurement is now entirely mandated by Commission programs.

In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms, like technology targets that allow only a subset of those options.[78] Studies have also shown that renewable electricity mandates increase prices and costs,[79] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants; and second, by creating a less robust market for participants to compete.[80] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location, and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

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78 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at https://www.rff.org/publications/working-papers/cost-effectiveness-of-renewable-electricity-policies/); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

79 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call"; Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

80 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at https://www.rff.org/publications/journal-articles/combining-policies-for-renewable-energy-is-the-whole-less-than-the-sum-of-its-parts/.)

14. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's 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), this section is divided into separate discussions addressing each of these situations.

14.1 Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2019 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct sets the standard that PG&E employees will put safety first.[81] PG&E's commitment to a safety-first culture is reinforced by a speak-up culture.[82] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

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81 *See* PG&E, "Employee Code of Conduct" (February 2018) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 4 (available at https://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/SupplierCodeofConductPGE.pdf).

82 *See* PG&E, "Employee Code of Conduct" *supra*, p. 21 *et seq.*

The top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E 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 CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance ("O&M") 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.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

Regarding employee safety, 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. Employees also participate in activities developed and conducted by an employee-led Driver Awareness Team established for the sole purpose of improving driving safety.

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

- Contractor Safety Oversight Program,
- Training and recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- 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
- Near Hit (close call) reporting
- Employee injury case management
- Safety performance recognition
- Public safety awareness
- Corrective Actions Program

The safety focus of PG&E's hydroelectric operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our 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. Regarding public safety, PG&E has developed and implemented a comprehensive public safety program that includes: (1) Dam Safety program; (2) public education, outreach, and partnership with key agencies; (3) improved warning and hazard signage at hydro facilities; (4) enhanced emergency response preparedness, training, drills, and coordination with emergency response organizations; and (5) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E's Dam Safety Program is responsible for ensuring the long-term safe and reliable operation of PG&E's dams by all company personnel, and for ensuring that power production or other business objectives do not take precedence over dam safety or regulatory compliance. PG&E's dams are regulated by both the Federal Energy Regulatory Commission ("FERC") and the California Department of Water Resources Division of Safety of Dams ("DSOD"). PG&E's Dam Safety Program was developed in line with FERC requirements. The Dam Safety Program's objectives include the following:

- Maintaining a well-trained and resourced organization, with a primary focus on public and employee safety as well as compliance with FERC and DSOD requirements for dam safety;
- Communicating policies and expectations regarding dam safety and regulatory compliance to all Dam Safety Program team members, O&M personnel, and other stakeholders;
- Defining protocols for communicating and reporting dam safety issues;
- Defining the responsibilities and authority of the Chief Dam Safety Engineer;
- Providing and implementing a comprehensive training plan for dam safety, formal dam safety quality assurance and quality control programs, and a dam safety inspection program; and
- Requiring internal and external audits and assessments to verify and document compliance and maintain an ongoing focus on dam safety and regulatory compliance.

To carry out these objectives, the Dam Safety Program provides engineering and other construction support and analysis, inspection services, dam surveillance and monitoring services, maintenance procedures and emergency action plans, dam security, and the development of other safety-related standards and procedures. The Dam Safety Program also convenes and seeks the input of an independent Dam Safety Advisory Board consisting of industry experts in dam safety.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as arc flash hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that acts to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

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

The vast majority of PG&E's 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. PG&E's contract provisions reinforce the developer's obligations to safety by requiring them 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, PG&E's recent energy storage contract provisions seek to instill a continuous improvement safety culture that mirrors PG&E's "Contractor Safety Standard" pursuant to D.15-07-014. These provisions require developers to demonstrate their use of safeguards, equipment, and personnel training, and require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. Such provisions were included in the executed agreements arising out of the 2014 and 2016 Energy Storage RFOs and could be incorporated in future RPS contracts if PG&E's RPS position resulted in a need for RPS procurement. The safety related contract provisions within PG&E's form RPS contracts may be further modified in a future RPS procurement solicitation to include safety contract provisions similar to those included in PG&E's previous energy storage contracts if any specific projects are expected to pose elevated safety risks, based on PG&E's review of factors such as the generation technology's risk profile, proximity of any projects to sensitive locations, or other project specific considerations.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

15. Comments on Coordination with Integrated Resource Planning Proceeding

PG&E supports close alignment between the IRP proceeding[83] and the RPS proceeding, with the IRP comparing RPS resources against other GHG-free resources, including demand-side alternatives such as EE and rooftop solar. In light of the overlap in reporting requirements between the RPS and IRP proceedings, the 2019 RPS Plan Ruling proposed a process in which annual RPS filing requirements can be satisfied by the LSEs' filing of their IRP Plans in the years that IRP Plans are required.[84] The Commission sought comments from parties on the proposal, and those comments will be submitted after the filing of this Draft 2019 RPS Plan.[85]

In accordance with the 2019 RPS Plan Ruling, PG&E expects to file opening and reply comments on the proposal to better integrate the IRP and RPS Plan proceedings. PG&E will then summarize in this Section of its Final, Conforming 2019 RPS Plan any

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83 The current IRP proceeding is R.16-02-007.

84 2019 RPS Plan Ruling, pp. 24-26.

85 *Id.*, p. 24; Attach. A.

order by the Commission in its decision on the Draft 2019 RPS Plans with regard to future RPS and IRP coordination.

APPENDIX A.1

Renewable Net Short Calculations

Table 1: Renewable Net Short Calculation as of May 2019

Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2019 - 2023) and LTPP Methodology (2024 - 2036)

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Actuals	2016 Actuals	2014-2016	2017 Actuals	2018 Actuals
			Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-
			Annual RPS Requirement											
A			Bundled Retail Sales Forecast (LTPP)[1]		74,864	76,205	75,705	226,774	74,547	72,113	68,441	215,101	61,397	48,832
B			RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	14,161
D			Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	14,161
			RPS-Eligible Procurement											
Fa			Risk-Adjusted RECs from Online Generation[3]		14,699	14,513	17,212	46,424	20,207	21,285	22,551	64,042	22,345	20,453
Faa			Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[4]		-	-	-	-	-	-	0	-	-	-
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc			Pre-Approved Generic RECs		-	-	-	-	-	-	-	-	-	-
Fd			Executed REC Sales		-	-	(142)	(142)	(50)	-	(60)	(110)	(2,069)	(1,451)
F	Fa + Fb +Fc - Fd	Fa + Fb +Fc + Fd	Total RPS Eligible Procurement (GWh)[5]		14,699	14,513	17,069	46,281	20,157	21,285	22,491	63,932	20,276	19,002
F0			Category 0 RECs		14,651	13,049	14,163	41,863	16,899	17,408	17,914	52,222	14,804	13,461
F1			Category 1 RECs		48	1,464	2,906	4,418	3,257	3,876	4,577	11,710	5,471	5,542
F2			Category 2 RECs		-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs		-	-	-	-	-	-	-	-	-	-
			Gross RPS Position (Physical Net Short)											
Ga	F-E		**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841
Gb	F/A		**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	38.9%
			Application of Bank											
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR[6,7]		-	(274)	(1,033)	-	861	4,815	9,274	861	14,630	18,200
Hb			RECs above the PQR added to Bank		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841
Hc			Non-bankable RECs above the PQR[8]		-	31	34	65	26	23	25	74	129	2
H	Ha+Hb		Gross Balance of RECs above the PQR		(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	23,041
Ia			Planned Application of RECs above the PQR towards RPS Compliance		-	-	-	-	-	-	-	-	-	-
Ib			Planned Sales of RECs above the PQR[9]		-	-	-	-	-	-	-	-	-	-
J	H-Ia-Ib	H-Ia+Ib	Net Balance of RECs above the PQR[6]		(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	23,038
J0			Category 0 RECs		-	-	-	-	657	1,237	2,019	2,067	2,067	2,067
J1			Category 1 RECs		-	-	895	926	4,184	8,060	12,636	12,636	16,261	20,971
J2			Category 2 RECs		-	-	-	-	-	-	-	-	-	-
			Expiring Contracts											
K			RECs from Expiring RPS Contracts[10]		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
			Net RPS Position (Optimized Net Short)											
La	Ga + Ia – Ib – Hc	Ga + Ia + Ib	**Annual Net RPS Position after Bank Optimization (GWh)[11]**		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841
Lb	(F + Ia – Ib – Hc)/ A	(C + La) / A	**Annual Net RPS Position after Bank Optimization (%)[11,12]**		19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	38.9%

Variable	Item	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast
	Forecast Year	-	-	CP3	-	-	-	-	CP4	-	-	-
	Annual RPS Requirement											
A	Bundled Retail Sales Forecast (LTPP)[1]	[redacted]	33,902	[redacted]	[redacted]	[redacted]	31,138	35,687	133,136	35,602	35,355	35,115
B	RPS Procurement Quantity Requirement (%)	31.0%	33.0%	30.0%	35.8%	38.5%	41.3%	44.0%	39.9%	46.7%	50.0%	52.0%
C	**Gross RPS Procurement Quantity Requirement (GWh)**	[redacted]	11,188	[redacted]	[redacted]	[redacted]	12,845	15,702	53,148	16,614	17,677	18,260
D	Voluntary Margin of Over-procurement[2]	-	-	-	-	-	-	-	-	-	-	-
E	**Net RPS Procurement Need (GWh)**	[redacted]	11,188	[redacted]	[redacted]	[redacted]	12,845	15,702	53,148	16,614	17,677	18,260
	RPS-Eligible Procurement											
Fa	Risk-Adjusted RECs from Online Generation[3]	20,455	20,367	83,621	20,108	17,650	16,809	16,530	71,097	16,365	15,834	15,550
Faa	Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb	Risk-Adjusted RECs from RPS Facilities in Development[4]	38	172	209	562	573	573	572	2,280	569	567	564
Fbb	Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc	Pre-Approved Generic RECs	-	149	149	217	405	1,038	1,213	2,872	1,197	1,305	1,343
Fd	Executed REC Sales	(10,000)	(7,952)	(21,472)	(916)	(617)	(617)	(618)	(2,768)	(468)	(442)	(394)
F	Total RPS Eligible Procurement (GWh)[5]	10,493	12,736	62,507	19,971	18,011	17,803	17,697	73,481	17,663	17,263	17,063
F0	Category 0 RECs	9,406	12,350	50,021	13,290	11,227	10,932	10,704	46,153	10,579	10,070	9,813
F1	Category 1 RECs	4,564	5,027	20,604	7,512	7,566	7,257	7,378	29,713	7,466	7,574	7,628
F2	Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-
F3	Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-
	Gross RPS Position (Physical Net Short)											
Ga	**Annual Gross RPS Position (GWh)**	[redacted]	1,548	[redacted]	[redacted]	[redacted]	4,958	1,994	20,333	1,048	(414)	(1,196)
Gb	**Annual Gross RPS Position (%)**	[redacted]	37.6%	[redacted]	[redacted]	[redacted]	57.2%	49.6%	55.2%	49.6%	48.8%	48.6%
	Application of Bank											
Ha	Existing Banked RECs above the PQR[6,7]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb	RECs above the PQR added to Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hc	Non-bankable RECs above the PQR[8]	-	-	132	-	-	-	-	-	-	-	-
H	Gross Balance of RECs above the PQR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia	Planned Application of RECs above the PQR towards RPS Compliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib	Planned Sales of RECs above the PQR[9]	-	-	-	(5,093)	(5,300)	(4,800)	(4,400)	(19,593)	(3,900)	(2,600)	(1,700)
J	Net Balance of RECs above the PQR[6]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0	Category 0 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1	Category 1 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2	Category 2 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Expiring Contracts											
K	RECs from Expiring RPS Contracts[10]	432	746	1,178	1,046	3,460	4,160	4,437	13,104	4,500	4,981	5,192
	Net RPS Position (Optimized Net Short)											
La	**Annual Net RPS Position after Bank Optimization (GWh)[11]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	**Annual Net RPS Position after Bank Optimization (%)[11,12]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable	Item	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033	2034 Forecast	2035 Forecast	2036 Forecast	2034 - 2036
	Forecast Year	CP5	-	-	-	CP6	-	-	-	CP7	-	-	-	CP8
	Annual RPS Requirement													
A	Bundled Retail Sales Forecast (LTPP)[1]	106,072	34,792	34,505	34,187	103,485	33,872	33,559	33,250	100,681	32,943	32,639	32,338	97,921
B	RPS Procurement Quantity Requirement (%)	49.6%	54.7%	57.3%	60.0%	57.3%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
C	**Gross RPS Procurement Quantity Requirement (GWh)**	52,551	19,020	19,783	20,512	59,315	20,323	20,136	19,950	60,409	19,766	19,584	19,403	58,753
D	Voluntary Margin of Over-procurement[2]	-	-	-	-	-	-	-	-	-	-	-	-	-
E	**Net RPS Procurement Need (GWh)**	52,551	19,020	19,783	20,512	59,315	20,323	20,136	19,950	60,409	19,766	19,584	19,403	58,753
	RPS-Eligible Procurement													
Fa	Risk-Adjusted RECs from Online Generation[3]	47,748	15,505	14,924	14,852	45,281	14,154	13,613	12,386	40,154	11,104	10,104	9,688	30,896
Faa	Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb	Risk-Adjusted RECs from RPS Facilities in Development[4]	1,700	563	560	558	1,681	556	555	551	1,662	542	474	150	1,166
Fbb	Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc	Pre-Approved Generic RECs	3,846	982	979	978	2,938	977	978	975	2,929	974	973	974	2,920
Fd	Executed REC Sales	(1,304)	-	-	-	-	-	-	-	-	-	-	-	-
F	Total RPS Eligible Procurement (GWh)[5]	51,989	17,050	16,463	16,387	49,900	15,687	15,146	13,912	44,745	12,619	11,551	10,812	34,982
F0	Category 0 RECs	30,462	9,778	9,245	9,198	28,221	8,588	8,490	7,854	24,932	7,219	6,768	6,756	20,743
F1	Category 1 RECs	22,669	7,649	7,593	7,562	22,805	7,470	7,026	6,425	20,921	5,400	4,783	4,056	14,239
F2	Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-
F3	Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gross RPS Position (Physical Net Short)													
Ga	**Annual Gross RPS Position (GWh)**	(562)	(1,970)	(3,320)	(4,125)	(9,415)	(4,636)	(4,990)	(6,038)	(15,664)	(7,147)	(8,032)	(8,591)	(23,770)
Gb	**Annual Gross RPS Position (%)**	49.0%	49.0%	47.7%	47.9%	48.2%	46.3%	45.1%	41.8%	44.4%	38.3%	35.4%	33.4%	35.7%
	Application of Bank													
Ha	Existing Banked RECs above the PQR[6,7]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb	RECs above the PQR added to Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hc	Non-bankable RECs above the PQR[8]	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Gross Balance of RECs above the PQR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia	Planned Application of RECs above the PQR towards RPS Compliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib	Planned Sales of RECs above the PQR[9]	(8,200)	(700)	-	-	(700)	-	-	-	-	-	-	-	-
J	Net Balance of RECs above the PQR[6]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0	Category 0 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1	Category 1 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2	Category 2 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Expiring Contracts													
K	RECs from Expiring RPS Contracts[10]	14,674	5,245	5,722	5,747	16,714	6,066	6,609	7,868	20,543	9,647	10,760	11,745	32,152
	Net RPS Position (Optimized Net Short)													
La	**Annual Net RPS Position after Bank Optimization (GWh)[11]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	**Annual Net RPS Position after Bank Optimization (%)[11,12]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) Forecasts of retail sales through 2023 are reflective of PG&E's internal bundled retail sales forecast less interdepartmental (metered usage at PG&E-owned facilities) and GTSR sales.

Forecasts post-2023 use the 2017-2018 IRP Cycle forecast (successor to LTPP proceeding planning process).

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See Draft 2018 RPS Plan for a description of PG&E's VMOP.

(3) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(4) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(5) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(6) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J may differ from Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.

(7) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(8) (Row Hc) Since PG&E elected to comply early in the 2017-2020 period with the banking rules established in D.17-06-026, PG&E has modeled the new banking rules for the current and future compliance periods.

(9) (Row Ib) The annual RPS sales volume forecast assumption is based on RPS sales executed in 2018 as well as the RPS sales framework proposed in PG&E's 2019 RPS Plan, and is included for RPS position planning purposes. Row Ib is reduced by executed REC sales volumes included on Row Fd.

(10) (Row K) Row K now includes only expiring volumes from contracts as of June 2019.

(11) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(12) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization.

APPENDIX A.2

Alternate Renewable Net Short Calculations

Table 2: Alternative Renewable Net Short Calculation as of May 2019

Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Actuals	2016 Actuals	2014-2016	2017 Actuals	2018 Actuals	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033	2034 Forecast	2035 Forecast	2036 Forecast	2034 - 2036
			Forecast Year	-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	CP4	-	-	-	CP5	-	-	-	CP6	-	-	-	CP7	-	-	-	CP8
			Annual RPS Requirement																																		
A			Bundled Retail Sales Forecast (Alternate)[1]	74,864	76,205	75,705	226,774	74,547	72,113	68,441	215,101	61,397	48,832	[redacted]	33,902	[redacted]			31,138	29,785	127,234	29,319	29,192	29,344	87,855	29,715	30,184	30,796	90,696	31,455	32,231	33,234	96,921	34,164	35,233	36,371	105,768
B			RPS Procurement Quantity Requirement (%)[2]	20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	35.8%	38.5%	41.3%	44.0%	39.9%	46.7%	50.0%	52.0%	49.6%	54.7%	57.3%	60.0%	57.3%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**	14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	14,161	[redacted]	11,188	[redacted]			12,845	13,105	50,551	13,682	14,596	15,259	43,537	16,244	17,305	18,478	52,028	18,873	19,339	19,941	58,152	20,498	21,140	21,823	63,461
D			Voluntary Margin of Over-procurement[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**	14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	14,161	[redacted]	11,188	[redacted]			12,845	13,105	50,551	13,682	14,596	15,259	43,537	16,244	17,305	18,478	52,028	18,873	19,339	19,941	58,152	20,498	21,140	21,823	63,461
			RPS-Eligible Procurement																																		
Fa			Risk-Adjusted RECs from Online Generation[4]	14,699	14,513	17,212	46,424	20,207	21,285	22,551	64,042	22,345	20,453	20,455	20,367	83,621	20,108	17,650	16,809	16,530	71,097	16,365	15,834	15,550	47,748	15,505	14,924	14,852	45,281	14,154	13,613	12,386	40,154	11,104	10,104	9,688	30,896
Faa			Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[5]	-	-	-	-	-	-	-	-	-	-	38	172	209	562	573	573	572	2,280	569	567	564	1,700	563	560	558	1,681	556	555	551	1,662	542	474	150	1,166
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc			Pre-Approved Generic RECs	-	-	-	-	-	-	-	-	-	-	-	149	149	217	405	1,038	1,213	2,872	1,197	1,305	1,343	3,846	982	979	978	2,938	977	978	975	2,929	974	973	974	2,920
Fd			Executed REC Sales	-	-	(142)	(142)	(50)	-	(60)	(110)	(2,069)	(1,451)	(10,000)	(7,952)	(21,472)	(916)	(617)	(617)	(618)	(2,768)	(468)	(442)	(394)	(1,304)	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd		Total RPS Eligible Procurement (GWh)[6]	14,699	14,513	17,069	46,281	20,157	21,285	22,491	63,932	20,276	19,002	10,493	12,736	62,507	19,971	18,011	17,803	17,697	73,481	17,663	17,263	17,063	51,989	17,050	16,463	16,387	49,900	15,687	15,146	13,912	44,745	12,619	11,551	10,812	34,982
F0			Category 0 RECs	14,651	13,049	14,163	41,863	16,899	17,408	17,914	52,222	14,804	13,461	9,406	12,350	50,021	13,290	11,227	10,932	10,704	46,153	10,579	10,070	9,813	30,462	9,778	9,245	9,198	28,221	8,588	8,490	7,854	24,932	7,219	6,768	6,756	20,743
F1			Category 1 RECs	48	1,464	2,906	4,418	3,257	3,876	4,577	11,710	5,471	5,542	4,564	5,027	20,604	7,512	7,566	7,257	7,378	29,713	7,466	7,574	7,628	22,669	7,649	7,593	7,562	22,805	7,470	7,026	6,425	20,921	5,400	4,783	4,056	14,239
F2			Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Step 1 Result: Physical Net Short[7]																																		
Ga	F-E		**Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841	[redacted]	1,548	[redacted]			4,958	4,591	22,930	3,980	2,667	1,805	8,452	806	(842)	(2,090)	(2,127)	(3,186)	(4,193)	(6,028)	(13,407)	(7,879)	(9,588)	(11,011)	(28,479)
Gb	F/A		**Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	38.9%	[redacted]	37.6%	[redacted]			57.2%	59.4%	57.8%	60.2%	59.1%	58.1%	59.2%	57.4%	54.5%	53.2%	55.0%	49.9%	47.0%	41.9%	46.2%	36.9%	32.8%	29.7%	33.1%

PG&E's Alternative RNS Table - Stochastic-Adjustment (2019-2033)[8]

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2014-2016	2017 Actuals	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033
			Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[9]																														
Gd			**Stochastically-Adjusted Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841	[redacted]																			
Ge			**Stochastically-Adjusted Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	38.9%	[redacted]																			
			Application of Bank																														
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[10,11]	-	(274)	(1,053)	-	861	4,815	9,274	861	14,630	18,200	[redacted]																			
Hb			RECs above the PQR added to Bank	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841	[redacted]																			
Hc			Non-bankable RECs above the PQR	-	31	34	65	26	23	25	74	129	2	-	-	132	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR	(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	23,041	[redacted]																			
Ia			Planned Application of RECs above the PQR towards RPS Compliance	-	-	-	-	-	-	-	-	-	-	[redacted]																			
Ib			Planned Sales of RECs above the PQR[12]	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,093)	(5,300)	(4,800)	(4,400)	(19,593)	(3,900)	(2,600)	(1,700)	(8,200)	(700)	-	-	(700)	-	-	-	-
J	H-Ia-Ib	H-Ia+Ib	Net Balance of RECs above the PQR (The Bank at End of Period)[10]	(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	23,038	[redacted]																			
J0			Category 0 RECs	-	-	-	-	657	1,237	2,019	2,067	2,067	2,067	[redacted]																			
J1			Category 1 RECs	-	-	895	926	4,184	8,060	12,636	12,636	16,261	20,971	[redacted]																			
J2			Category 2 RECs	-	-	-	-	-	-	-	-	-	-	[redacted]																			
			Expiring Contracts																														
K			RECs from Expiring RPS Contracts[13]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	432	746	1,178	1,046	3,460	4,160	4,437	13,104	4,500	4,981	5,192	14,674	5,245	5,722	5,747	16,714	6,066	6,609	7,868	20,543
			Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[14]																														
La	Ga + Ia - Ib - Hc	Gd+Ia+Ib	**Annual Net RPS Position after Bank Optimization (GWh)[14]**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	4,841	[redacted]																			
Lb	(F + Ia - Ib - Hc)/A	(C + La) / A	**Annual Net RPS Position after Bank Optimization (%)[14]**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	38.9%	[redacted]																			

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) PG&E uses its April 2019 internal bundled retail sales forecast less interdepartmental (metered usage at PG&E-owned facilities) and GTSR sales for its procurement decisions.

(2) (Row B) RPS procurement quantity requirement percentages are based on the updated RPS requirements from SB 100.

(3) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See Draft 2018 RPS Plan for a description of PG&E's VMOP.

(4) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(5) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(6) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(7) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the IRP forecast provided in the RNS.

(8) The stochastic model optimizes from 2019 to 2033

(9) Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2017 RPS Plan.
This is prior to any application of the Bank.

(10) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.

(11) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(12) (Row Ib) The annual RPS sales volume forecast assumption is based on RPS sales executed in 2018 as well as the RPS sales framework proposed in PG&E's 2019 RPS Plan, and is included for RPS position planning purposes. Row Ib is reduced by executed REC sales volumes included on Row Fd.

(13) (Row K) Row K now includes only expiring volumes from contracts as of June 2019.

(14) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

*Stochastic Results in Rows Gd-Lb reflect a May 2019 stochastic modeling vintage.

APPENDIX B

Procurement Information Related to Cost Quantification

Appendix B – Procurement Information Related to Cost Quantification

Assumptions	
Table 1 (Actual Costs, $) Items	**Actual**
Rows 2 – 8, 11 (2003-2018)[1,2,3,4]	Settled contract costs with all Renewable Portfolio Standard (RPS)-eligible contracts in Pacific Gas and Electric Company's (PG&E) portfolio for 2003-2018.
Row 9	For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 through 2017, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-2017) were added to each year's capital costs to calculate total costs. 2018 costs are fully allocated revenue requirements (2017 General Rate Case (GRC)).
Row 10	2003-2017 LCOE for each project multiplied by the project's historical generation. 2018 costs are revenue requirments (2017 GRC).
Row 12	Renewable Energy Credit (REC) Sales Revenues
Row 13	**Total RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]
Row 14	PG&E actual bundled retail sales
Row 15	Total Cost/Bundled Retail Sales (Row 13/Row 14)
Table 2 (Forecast Costs, $) Items	**Forecast**
Rows 2 – 8, 11, 17 – 26	PG&E's future expenditures on all RPS-eligible procurement and generation approved to date. 2019 forecast data are consistent with the 2019 ERRA Forecast Application, filed at the California Public Utilities Commission (CPUC) November, 2018.
Rows 9 and 24	Utility-Owned Generation (UOG) small hydro forecast fully allocated revenue requirements
Rows 10 and 25	UOG solar forecast fully allocated revenue requirements
Rows 12 and 27	PG&E forecasted REC sales revenue
Row 13 and 28	Row 13 = Sum of Rows 2 through 11; Row 28 = Sum of Rows 16 through 25
Rows 14 and 29	PG&E bundled retail sales forecast
Rows 15 and 30	Total Cost/Bundled Sales
Row 31	Row 15 + Row 30
Table 3 (Actual Generation, MWh) Items	**Actual**
Rows 2 – 11,	Generation (MWh) associated with payments for RPS-eligible deliveries
Table 4 (Forecast Generation, MWh) Items	**Forecast**
Rows 2 – 11 and 15 – 25	Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to July 2019 but pending Commission approval—assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2019 forecast uses September 2018 contract vintage. 2020-2030 uses June 2019 contract vintage.
Rows 12 and 26	PG&E RECs sold volume

[1] 2016 Generation and Costs were updated to correctly account for Green Tariff Shared Renewables Program impacts.

[2] Row 5 includes the aggregate costs (specifically debt service and O&M) of PG&E's contract with Solano Irrigation District who supplies power from multiple hydro units, 100% of which are RPS-eligible. Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

[3] Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

[4] Prior to 2018, costs for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract. 2018 aggregate REC sales are shown as a separate line item.

Note: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs							
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,468	$27,306	$20,216
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053
5	Small Hydro	$60,984	$57,470	$80,340	$97,340	$63,161	$72,488	$52,053	$63,296
6	Solar PV	$0	$0	$0	$0	$0	$0	$2,554	$10,180
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$65,244	$74,912	$56,891	$67,116	$98,203	$102,516	$199,475	$224,089
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,498
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0
12	**Rec Sales Revenue**	$0	$0	$0	$0	$0	$0	$0	$0
13	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$522,576**	**$530,998**	**$535,380**	**$575,483**	**$671,317**	**$790,116**	**$791,870**	**$893,010**
14	Bundled Retail Sales[2] [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129
15	**Incremental Rate Impact[3]**	**0.73 ¢/kWh**	**0.74 ¢/kWh**	**0.74 ¢/kWh**	**0.75 ¢/kWh**	**0.85 ¢/kWh**	**0.97 ¢/kWh**	**0.99 ¢/kWh**	**1.15 ¢/kWh**

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row.
[2] The rates calculated in the Cost Quantification Template do not reflect allocated costs to departed load (e.g., DA and CCA customers), therefore these illustrative rates will overestimate the actual impacts on forecasted bundled rates.
[3] Incremental Rate Impact is equal to Row 13 divided by Row 14 (in following table either Row 13 or 28 divided by Row 14 or 29, respectively). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1 (continued)
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs							
1	**Technology Type**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
2	Biogas	$16,776	$5,333	$5,063	$11,087	$22,283	$26,294	$31,071	$34,429
3	Biomass	$245,622	$302,711	$299,205	$317,301	$286,766	$254,294	$202,416	$183,458
4	Geothermal	$223,575	$209,854	$284,334	$324,050	$280,843	$273,751	$288,807	$197,930
5	Small Hydro	$84,864	$54,140	$57,213	$45,522	$34,247	$64,646	$67,486	$46,665
6	Solar PV	$33,370	$176,372	$504,860	$803,806	$949,556	$977,619	$952,115	$1,025,403
7	Solar Thermal	$0	$0	$1,698	$173,856	$296,915	$340,074	$324,052	$331,221
8	Wind	$340,517	$379,416	$424,764	$437,159	$422,102	$422,518	$401,179	$379,171
9	UOG Small Hydro	$52,099	$51,572	$64,691	$66,066	$74,770	$108,830	$94,597	$193,105
10	UOG Solar	$5,620	$27,093	$43,882	$52,426	$49,535	$48,527	$45,550	$65,009
11	Unbundled RECs[1]	$823	$871	$677	$805	$705	$0.00	$0.00	$0.00
12	Rec Sales Revenue	$0	$0	$0	$0	$0	$0	$0	-$7,390
13	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$1,003,268**	**$1,207,361**	**$1,686,387**	**$2,232,077**	**$2,417,720**	**$2,516,552**	**$2,407,272**	**$2,456,390**
14	Bundled Retail Sales[2] [Thousands of kWh]	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848	68,440,794	61,397,214	48,832,111
15	**Incremental Rate Impact[3]**	**1.34 ¢/kWh**	**1.58 ¢/kWh**	**2.23 ¢/kWh**	**2.99 ¢/kWh**	**3.35 ¢/kWh**	**3.68 ¢/kWh**	**3.92 ¢/kWh**	**5.03 ¢/kWh**

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row.
[2] The rates calculated in the Cost Quantification Template do not reflect allocated costs to departed load (e.g., DA and CCA customers), therefore these illustrative rates will overestimate the actual impacts on forecasted bundled rates.
[3] Incremental Rate Impact is equal to Row 13 divided by Row 14 (in following table either Row 13 or 28 divided by Row 14 or 29, respectively). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs						
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
2	Biogas	$0	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0
12	REC Sales Revenue[2]	$0	$0	$0	$0	$0	$0	$0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
14	Bundled Retail Sales[3] (Thousands of kWh)	[redacted]	33,902,450	[redacted]	[redacted]	31,138,247	29,784,969	29,319,384
15	**Incremental Rate Impact[4]**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**

[1] See footnote 1 from Table 1.
[2] Volumes in this row include a forecast of bundled REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.
[3] See footnote 2 from Table 1.
[4] See footnote 3 from Table 1.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs						
16	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
17	Biogas	$40,085	$43,259	$48,586	$59,723	$68,329	$68,368	$67,731
18	Biomass	$198,966	$187,173	$190,855	$197,490	$208,413	$232,436	$226,625
19	Geothermal	$192,263	$202,231	$192,931	$12,534	$12,449	$12,402	$12,303
20	Small Hydro	$54,998	$41,635	$39,204	$37,169	$38,412	$38,699	$38,479
21	Solar PV	$1,027,013	$1,080,553	$1,087,466	$1,086,315	$1,086,085	$1,087,465	$1,087,415
22	Solar Thermal	$317,166	$332,956	$331,176	$331,480	$330,822	$330,756	$330,980
23	Wind	$404,429	$402,204	$395,607	$389,746	$370,013	$345,624	$339,620
24	UOG Small Hydro	$181,488	$248,071	$254,144	$262,989	$265,608	$268,288	$271,029
25	UOG Solar	$67,073	$60,254	$61,876	$60,111	$59,205	$58,323	$57,462
26	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0
27	REC Sales Revenue[2]	[redacted]						
28	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 17 through 27]	[redacted]						
29	Bundled Retail Sales[3] (Thousands of kWh)	[redacted]	33,902,450	[redacted]		31,138,247	29,784,969	29,319,384
30	**Incremental Rate Impact[4]**	[redacted]						
31	**Total Incremental Rate Impact** [Row 15 + 30; Rounding can cause Row 31 to differ slightly from the sum of Row 15 and 30]	[redacted]						

[1] See footnote 1 from Table 1.
[2] Volumes in this row include a forecast of bundled REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.
[3] See footnote 2 from Table 1.
[4] See footnote 3 from Table 1.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs				
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0
12	REC Sales Revenue[2]	$0	$0	$0	$0	$0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$0**	**$0**	**$0**	**$0**	**$0**
14	Bundled Retail Sales (Thousands of kWh)	29,192,249	29,343,710	29,715,465	30,183,954	30,796,093
15	**Incremental Rate Impact[3]**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**
16	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2026**	**2027**	**2028**	**2029**	**2030**
17	Biogas	$67,402	$66,688	$66,863	$64,963	$64,700
18	Biomass	$234,816	$203,389	$155,472	$155,213	$155,427
19	Geothermal	$12,251	$12,175	$12,127	$12,011	$11,941
20	Small Hydro	$38,791	$39,158	$39,145	$33,862	$33,670
21	Solar PV	$1,091,053	$1,087,493	$1,086,042	$1,077,793	$1,074,442
22	Solar Thermal	$332,008	$331,518	$333,481	$332,345	$332,359
23	Wind	$285,253	$288,732	$292,221	$255,670	$254,915
24	UOG Small Hydro	$273,833	$276,701	$279,636	$282,638	$282,638
25	UOG Solar	$56,624	$55,807	$55,012	$54,238	$54,238
26	Unbundled RECs[1]	$0	$0	$0	$0	$0
27	REC Sales Revenue[2]	[redacted]				
28	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 17 through 27]					
29	Bundled Retail Sales[3] (Thousands of kWh)	29,192,249	29,343,710	29,715,465	30,183,954	30,796,093
30	**Incremental Rate Impact[4]**	[redacted]				
31	**Total Incremental Rate Impact** [Row 15 + 30; Rounding can cause Row 31 to differ slightly from the sum of Row 15 and 30]					

[1] See footnote 1 from Table 1.
[2] Volumes in this row include a forecast of bundled REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.
[3] See footnote 2 from Table 1.
[4] See footnote 3 from Table 1.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 3
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)							
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2	Biogas	364,745	333,897	366,514	300,943	293,147	280,795	342,362	306,909
3	Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615
4	Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700
5	Small Hydro	1,269,233	1,096,183	1,457,339	1,760,707	927,879	945,921	937,626	1,092,707
6	Solar PV	6	4	4	3	1	1	21,706	58,593
7	Solar Thermal	0	0	0	0	0	0	0	0
8	Wind	940,239	1,078,579	874,204	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660
9	UOG Small Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077
10	UOG Solar	0	0	0	0	225	445	504	4,642
11	Unbundled RECs	0	0	0	0	0	0	0	0
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	8,471,654	8,490,423	8,647,195	9,079,568	9,033,979	9,824,276	11,497,048	12,358,903

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 3 (continued)
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)							
1	**Technology Type**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
2	Biogas	284,129	112,153	85,706	112,161	212,975	245,242	278,471	274,159
3	Biomass	3,043,656	3,158,131	3,055,370	3,226,904	2,814,468	2,709,612	1,935,092	1,827,867
4	Geothermal	3,780,954	3,807,728	3,687,236	3,870,952	3,646,936	3,719,139	2,796,245	2,332,443
5	Small Hydro	1,457,714	863,606	652,953	400,300	304,368	941,004	953,601	601,162
6	Solar PV	179,171	1,006,145	3,358,366	5,266,030	6,260,429	6,517,251	6,480,621	7,390,296
7	Solar Thermal	0	0	20,581	878,905	1,557,412	1,750,981	1,464,827	1,746,472
8	Wind	4,395,377	4,515,452	4,924,052	5,358,546	5,418,594	5,400,931	5,033,470	4,763,815
9	UOG Small Hydro	1,254,638	948,734	929,639	580,990	537,838	891,763	918,916	716,947
10	UOG Solar	26,790	165,656	279,500	336,905	318,582	322,415	297,758	310,219
11	Unbundled RECs	102,888	108,874	101,256	100,581	88,107	0	0	0
12	RECs Sold	0	0	00	0	0	0	0	-450,000
13	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 12]	14,525,317	14,686,479	17,094,659	20,132,274	21,159,709	22,498,340	20,159,001	19,963,379

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries (MWh)						
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
2	Biogas	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0	0
12	RECs Sold[1]	0	0	0	0	0	0	0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 12]	0	0	0	0	0	0	0
14	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
15	Biogas	289,140	309,171	338,904	405,535	464,063	463,877	457,289
16	Biomass	1,734,496	1,506,667	1,507,120	1,524,062	1,536,208	1,664,139	1,575,694
17	Geothermal	2,318,642	2,312,786	2,305,580	141,062	140,244	139,869	138,621
18	Small Hydro	708,646	592,890	483,534	442,665	444,836	444,469	437,028
19	Solar PV	7,818,799	8,107,287	8,469,258	8,447,043	8,441,073	8,454,150	8,430,209
20	Solar Thermal	1,762,261	1,742,355	1,738,603	1,738,603	1,738,603	1,742,355	1,738,603
21	Wind	5,064,235	5,039,767	4,915,178	4,800,773	4,526,293	4,274,225	4,225,649
22	UOG Small Hydro	1,157,938	967,991	889,616	889,947	891,950	892,930	871,396
23	UOG Solar	324,702	323,731	321,333	319,661	317,998	317,048	314,699
24	Unbundled RECs	0	0	0	0	0	0	0
25	RECs Sold[1]	-6,001,525	-8,000,000	-6,000,000	-5,900,000	-5,400,000	-5,000,000	-4,400,000
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 15 through 25]	15,177,335	12,902,646	14,969,125	12,809,352	13,101,269	13,393,062	13,789,188

[1] Volumes in this row include a forecast of bundled REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.

Appendix B – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4 (continued)
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries (MWh)				
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	0	0	0	0	0
3	Biomass	0	0	0	0	0
4	Geothermal	0	0	0	0	0
5	Small Hydro	0	0	0	0	0
6	Solar PV	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0
8	Wind	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0
10	UOG Solar	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0
12	RECs Sold	0	0	0	0	0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 12]	0	0	0	0	0
14	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2026**	**2027**	**2028**	**2029**	**2030**
15	Biogas	453,363	447,626	448,839	437,701	435,956
16	Biomass	1,612,055	1,395,333	981,000	978,179	978,179
17	Geothermal	137,817	137,017	136,651	135,432	134,646
18	Small Hydro	436,408	436,231	431,394	384,166	379,574
19	Solar PV	8,417,443	8,367,498	8,333,408	8,244,604	8,186,894
20	Solar Thermal	1,738,603	1,738,603	1,742,355	1,738,603	1,738,603
21	Wind	3,785,212	3,816,748	3,851,130	3,427,333	3,416,890
22	UOG Small Hydro	872,316	871,531	873,121	873,252	819,971
23	UOG Solar	313,062	311,434	310,503	308,203	306,600
24	Unbundled RECs	0	0	0	0	0
25	RECs Sold[1]	-3,000,000	-2,100,000	-700,000	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 15 through 25]	14,766,280	15,422,022	16,408,401	16,527,473	16,397,314

[1] Volumes in this row include a forecast of bundled REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.

APPENDIX C

Modeling Assumptions Informing Quantitative Calculations

Appendix C – Other Modeling Assumptions Informing Quantitative Calculation

Other Modeling Assumptions Informing Quantitative Calculation[2]

Assumptions Related to Procurement Quantity Requirement	
Compliance Periods	• As implemented by Decision ("D.") 11-12-020 and D.16-12-040, and as amended by Senate Bill ("SB") 100 (2018),[1] the Renewables Portfolio Standard ("RPS") statute requires retail sellers of electricity to meet the following RPS procurement quantity requirements beginning on January 1, 2011: ○ An average of 20 percent of the combined bundled retail sales during the first compliance period (2011-2013). ○ Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales). ○ Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales). ○ Sufficient procurement during the fourth compliance period (2021-2024) that is consistent with the following formula: (.358 * 2021 retail sales) + (.385 * 2022 retail sales) + (.413 * 2023 retail sales) + (.44 * 2024 retail sales). ○ Sufficient procurement during the fifth compliance period (2025-2027) that is consistent with the following formula: (.467 * 2025 retail sales) + (.493 * 2026 retail sales) + (.52 * 2027 retail sales). ○ Sufficient procurement during the sixth compliance period (2028-2030) that is consistent with the following formula: (.547 * 2028 retail sales) + (.573 * 2029 retail sales) + (.6 * 2030 retail sales). • 60 percent of bundled retail sales in 2031 and all years thereafter.

1 Pacific Gas and Electric Company (PG&E) is assuming, for purposes of this 2019 RPS Plan, that the California Public Utilities Commission will implement the SB 100 revised targets in the same "straight-line" manner as it implemented prior versions of the statutory RPS targets.

2 All assumptions in this table reflect a May 2019 data vintage (with the exception of the internal sales forecast, which uses an April 2019 vintage) which is consistent with the data vintage of Appendices A1–A2.

Appendix C – Other Modeling Assumptions Informing Quantitative Calculation

	Assumptions Related to Forecasted Generation
Non-Qualifying Facility ("QF") Projects *Contracts Executed Post-2002*	• Except for the "OFF/Closely Watched" contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100 percent of contract volumes, and deliveries commence within the allowed delay provisions in the contract.
QF Non-Hydro Projects *Contracts Executed Pre-2002*	• Forecast is typically based on an average of the three most recent calendar year deliveries. • Year 2019 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
QF Hydro *Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets*	• The forecast for hydro QFs is typically based on historical production, normalized for average year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. • Projects are forecasted based on the current expected generation for 2019 (based on PG&E's May 2019 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2019 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Non-QF Hydro *Utility-Owned Generation ("UOG") and Irrigation District Water Authority ("IDWA")*	• Forecasts reflect PG&E's best available projections for hydro conditions. • Projects are forecasted based on the current expected generation for 2019 (based on PG&E's May 2019 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2019 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.

Appendix C – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Generation	
Future Volumes From Pre-Approved Programs	**Renewable Market Adjusting Tariff (ReMAT)** • All deliveries from executed contracts are assumed at 100 percent of contract volumes. • Modeled start date for generic volumes assumed to begin 2020 and ramp up until 2027, reaching a total of ~122 megawatts (“MW”). **Bioenergy Market Adjusting Tariff (BioMAT)** • All deliveries from executed contracts are assumed at 100 percent of contract volumes. • Modeled start date for generic volumes assumed to begin 2021 and ramp up until 2023, reaching a total of ~65 MW.
Re-Contracting	• For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained: 1. PG&E does not yet have contractual commitments for these expiring volumes; 2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life; 3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and 4. PG&E’s current bundled load forecast does not support a re-contracting assumption. • Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources. • This forecasting methodology (i.e., not assuming any re-contracting) is consistent with PG&E’s Annual RPS compliance filing that only shows PG&E’s current contractual commitments.

Appendix C – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Generation	
Green Tariff Shared Renewables (“GTSR”)[3]	• PG&E allocates small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs. • When calculating PG&E’s RPS position, GTSR volumes are removed from PG&E’s RPS-eligible retail sales forecast. • PG&E incorporates any GTSR related impacts on its RPS–eligible generation into its RNS tables through 2036.
Banking	• PG&E assumes that: (1) grandfathered (pre-June 1, 2010) short-term products are bankable, and (2) that banked volumes may be applied in any period onward. ○ PG&E’s accounting is consistent with the direction set forth in D.12-06-038 for compliance periods one and two. Beginning with compliance period three, PG&E’s accounting is consistent with the direction set forth in D.17-06-026.
RPS Sales	• PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. The framework will be used to determine future sales of bankable RPS volumes. Details of PG&E’s sales framework are discussed in Appendix F.

3 PG&E will update its RNS following the dedication of any RPS resources currently included in the forecast of generation in the RNS to the DAC-GT Program.

Appendix C – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Sales	
Bundled Retail Sales *RNS (App. A.1)*	• Forecasts of retail sales for the first five years of the forecast (2019-2023) were generated by PG&E's *Load Forecasting and Research* team in April 2019, and may be updated throughout the year as additional data becomes available. • Forecasts of retail sales beyond the first five years are sourced from the 2017-2018 IRP Cycle forecast. The IRP has been identified as the successor to the LTPP proceeding planning process.
Bundled Retail Sales *Alternate RNS (App. A.2)*	• Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in April 2019 and may be updated throughout the year as additional data becomes available.

APPENDIX D

Responses to Renewable Net Short Questions

Appendix D – Responses to Renewable Net Short Questions

The following presents Pacific Gas and Electric Company's (PG&E) responses to questions set forth in the May 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

RPS Compliance Risk

1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. Appendix C to the Renewable Portfolio Standard (RPS) Plan discusses the assumptions PG&E has used to model future deliveries from RPS projects.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. The RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, Direct Access and Community Choice Aggregator participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is a April 2019 updated internal sales forecast. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts at least annually to reflect any new events and capture actual load changes. As described in more detail in its RPS Plan, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, making uncertainty around retail sales one of the largest drivers of RPS outcomes, particularly over time.

3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its Renewable Net Short (RNS). As described in the RPS Plan, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of 100% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, to 87% in PG&E's 2014 RPS Plan, 99 percent in PG&E's 2015 RPS Plan, and 100% in PG&E's 2016 RPS Plan to present.[1] This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short. See the answer to question #5 below for details on these new assumptions.

5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, PG&E may categorize projects experiencing considerable development challenges as "Closely Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in its RPS Plan. To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower.

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1 PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore, the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

Please see section 7.2.5, Table 7-3 for a comparison of uncertainty assumptions between PG&E's deterministic and stochastic models.

6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.

As described in Sections 8 and 9, PG&E plans to use a portion of its Bank as a Voluntary Margin of Over-Procurement (VMOP) to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section 8 for additional information.

7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.

As described in Sections 7 and 8, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted], projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use Renewable Energy Credits (REC) above the Procurement Quantity Requirements (PQR), as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes planned sales of RPS products, which is detailed in Appendix F.

<u>**VMOP**</u>

8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.

As discussed in Sections 8 and 9, 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. A portion of the Bank should be used to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the RPS targets, and will thus reduce long-term costs of the RPS Program.

9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.

As discussed in Sections 7 and 8, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus RPS volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E discusses a framework to assess whether to hold or to sell excess RPS volumes in Appendix F.

__Cost-Effectiveness__

10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?

As discussed in greater detail in Sections 7, 8, and 9 of this Plan, [redacted]

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?

PG&E's current RPS portfolio consists of Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy, as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the pre-Senate Bill (SB) 350 restrictions on banking of excess procurement have limited PG&E's ability to fully optimize its portfolio.

The changes to the RPS program under SB 350 enable banking of all Category 0 and 1 RECs of any duration, beginning in the 2021-2024 compliance period for all entities, or as early as the 2017-2020 compliance period for entities, like PG&E, that elect to comply early with the new SB 350 minimum long-term requirements. In addition, all retired Category 2 and Category 3 RECs that fall within the portfolio balance requirements are eligible to be counted towards PG&E's RPS procurement quantity requirement for the compliance period whether the RECs are associated with short-term or long-term contracts.

APPENDIX E.1

2020 Bundled RPS Energy Sales – Solicitation Protocol

Pacific Gas and Electric Company

2020 Bundled RPS Energy Sale - Solicitation Protocol

Issuance Date: __________, 2020

2020 Bundled RPS Energy Sale Solicitation Protocol

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LIST OF ATTACHMENTS

I. Overview

A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing the 2020 Bundled Renewables Portfolio Standard ("RPS") Energy Sale Solicitation ("Solicitation") to solicit bids ("Bids") from participants ("Participants") for bundled RPS-eligible energy and associated Renewable Energy Credits ("REC") (collectively, "Product") pursuant to a confirmation ("Agreement"). This Solicitation protocol ("Solicitation Protocol") describes the process by which PG&E seeks, evaluates, and accepts Bids in this solicitation from winning Participants.

The 2020 Bundled RPS Sale complies with PG&E's 2019 RPS Plan, which was approved by the California Public Utilities Commission ("CPUC" or "Commission") in Decision (D.) TBD).

PG&E will make all sales according to the terms and conditions set forth in the Agreement. This Solicitation Protocol sets forth the procedures a Participant must follow in order to participate in the Solicitation. Capitalized terms used in this Solicitation Protocol, but not otherwise defined herein, have the meanings set forth in the Agreement.

B. Bundled RPS Energy Sale Solicitation Communication

PG&E has established the Solicitation website at http://www.pge.com/rfo under "2020 Bundled RPS Energy Sale Solicitation." This site will be where Participants can register for the Solicitation. All Solicitation documents, information, announcements and questions and answers will be posted and available to Participants at this website.

To promote accuracy and consistency of the information provided to all Participants, PG&E encourages Participants to submit any inquiries via e-mail to RECSolicitations@pge.com for matters related to the Solicitation. With respect to matters of general interest raised by any Participants, PG&E may, without reference to the specific Participants raising such matter or initiating the inquiry, post the questions and responses on its website. PG&E may, in its sole discretion, decline to respond to any email or other inquiry.

Any exchange of material information regarding this Solicitation between Participants and PG&E must be submitted to both PG&E and the Independent Evaluator ("IE"). The IE is an independent, third party evaluator who is required by CPUC D.04-12-048 to ensure this Solicitation is conducted in a reasonable and neutral manner.

C. Schedule

The Solicitation schedule is subject to change to conform to any CPUC requirements but otherwise is at the discretion of PG&E. PG&E will post any schedule changes on PG&E's Solicitation website. Also, as further described below, Participants may register at PG&E's Request for Offer ("RFO") website to receive notice of these and other Solicitation changes by electronic mail. PG&E will have no liability or responsibility to any Participant for any change in the schedule or for failing to provide notice of any change.

The schedule for this Solicitation is (all times are in Pacific Prevailing Time):

Table 1: 2020 Bundled RPS Energy Sale Solicitation Schedule of Events

Date/Time	Event
Ongoing	Participants may register online at PG&E's RFO website to receive notices regarding the Solicitation.
TBD	PG&E issues the Solicitation.
TBD	Participants' Webinar.
TBD	Bids Due. Bid(s) must be submitted to the online platform at Power Advocate.
TBD	PG&E notifies qualified Participants.
TBD	PG&E and qualified Participants execute Agreement, which shall be subject to "CPUC Approval," as provided in the Agreement.
No later than 60 days after execution	PG&E submits Agreements for CPUC Approval.

D. Events in the Solicitation Schedule

a. Registration. Participants may register online to receive announcements and updates about this Solicitation through www.pge.com/rfo.

b. Issuance. PG&E will issue the Solicitation and post the Solicitation Protocol, form of Agreement, and all other solicitation materials on the Solicitation website.

c. Participants' Webinar. PG&E will hold a Participants' Webinar to review key Protocol items related to this solicitation.

d. Bids Due. Bids must be submitted via Power Advocate and must include all of the documents described in Section IV, Required Information. By submitting a Bid(s) and responding to this Solicitation, the Participant agrees to be bound by all of the terms, conditions and other provisions of this Solicitation and any changes or supplements to it that may be issued by PG&E.

e. PG&E Selects Bids. Selected Bids ("Selected Bids") will be notified via email. PG&E will select Bids according to the evaluation criteria described in Section III, Evaluation Criteria. Bids beyond the Selected Bids may be placed on a waitlist to be selected in order of evaluation results and selection constraints, should any Selected Bids fail to complete the Solicitation process.

f. Completion of Agreement. PG&E will complete Agreement with Participants with Selected Bids.

g. Execution and Regulatory Approval. PG&E will submit all such Agreements to the CPUC for approval via an advice letter filing. Additional regulatory approval information is provided in Section VII, Regulatory Approval.

E. Disclaimers for Rejecting Bids and/or Terminating This Solicitation

This Solicitation does not constitute an offer to sell and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the Solicitation. PG&E shall retain the right at any time, at its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this Solicitation and reserves the right to request information at any time during the Solicitation process.

PG&E retains the discretion, subject to, if applicable, the approval of the CPUC, to: (a) reject any Bid for any reason, including but not limited to the basis that a Bid is the result of market manipulation or is not cost-competitive or any other applicable reason; (b) modify this Solicitation and the form Agreement as it deems appropriate to implement the Solicitation and to comply with applicable law or other decisions or direction provided by the CPUC; and (c) terminate the Solicitation should the CPUC not authorize PG&E to sell the Product in the manner proposed in this Solicitation. In addition, PG&E reserves the right to either suspend or terminate this Solicitation at any time if such suspension is required by or with the approval of the CPUC. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this Solicitation Protocol to any Participant, whether submitting a Bid or not.

II. Solicitation Product and Goals

PG&E is seeking to sell Product with the exact volume to be determined based on the price of bids received.

A. Product Attributes

Product Attributes for 2020 Bundled RPS Energy Sale Solicitation	
Product	• Bundled RPS-eligible energy and associated RECs from resources in PG&E's portfolio.
Pricing	• Energy – settled at the day-ahead NP15, ZP26 and/or SP15 Index (Trading Hub Price) • REC – fixed price.
Location	• Selected by Seller in its discretion: NP15, SP15, and/or ZP26 Trading Hub.
Delivery Term	• TBD • Delivery start date occurs upon final CPUC Approval of Tier 1 AL.

III. Evaluation Criteria

PG&E will evaluate Bids using the evaluation criteria outlined below.

A. Quantitative Evaluation

For Bids in the 2020 RPS Sale, PG&E will consider Price offered as the sole quantitative criterion.

B. Qualitative Evaluation

For the Solicitation, PG&E may apply a qualitative adjustment factor for counterparties that have acceptable credit with PG&E and minimize proposed edits to the form of Agreement.

1. Credit

PG&E may consider the Participant's capability to perform all of its financial and financing obligations under the Agreement and PG&E's overall credit concentration with the Participant or its banks, including any of Participant's affiliates.

2. Agreement Modifications

PG&E has a strong preference for standardized Agreements and will assess the materiality and cost impact of any of Participant's proposed modifications to the Agreement. PG&E will only consider edits to the Agreement in the following sections:

- Quantity
- Green Attributes Price
- Delivery Term(s)
- Credit Terms

3. Other Qualitative Considerations

In addition to the criteria specifically listed above, PG&E may consider other qualitative factors that could impact the value of Bids, including, but not limited to: previous adverse commercial experience between PG&E and Participant; Participant concentration; and existence of an acceptable EEI Master Agreement between PG&E and Participant.

IV. Required Information

A. Submission Overview

All Bid submittal information pertaining to this Solicitation will be hosted on the Power Advocate site. Telephonic, hardcopy or facsimile transmission of a Bid is not acceptable. In order to participate in this Solicitation, Participants must register and be accepted through Power Advocate at the Public Registration Link:

[TBD]

PG&E strongly encourages Participants to register with Power Advocate at least a week before Bids are due. Detailed instructions for submitting Bid(s) and using Power Advocate are on PG&E's Solicitation website.

Electronic Documents: The electronic documents for the attachments must be in a Microsoft Word, Excel file or Adobe Acrobat PDF file as applicable. For each document, please include the Participants' company name in each file name.

B. Required Forms

1. **Bid Package**

The following documents, which are on the PG&E's Solicitation website, must be completed and included with each Bid(s):

a. Bid Form (Attachment A)

   i. Participant must provide all applicable information requested in the form, and all inputs must match the respective information provided in other required documentation.
   ii. From each counterparty, PG&E will only accept one Bid per delivery term. Brokers submitting on behalf of multiple counterparties may do so, but must designate the name of counterparty in the Bid Form.
   iii. PG&E will not accept Bids that are contingent on the selection of another bid.
   iv. Participant must agree to the Non-Disclosure attestation in the Bid Form.
   v. PG&E will not accept volumes below [TBD] megawatt-hours per Calendar year. Bids below these volumes will not be accepted;

b. Redline of Agreement (Attachment B);

c. Signed Non-Disclosure Agreement (Attachment C); and

d. Documentation of Entity Legal Status from the California Secretary of State:

i. Participant or end-user counterparty must demonstrate that it has an "Active" legal status authorized by the California Secretary of State in order to engage in business with PG&E. A webpage screenshot verifying Participant or end-user counterparty's "Active" legal status via the California Secretary of State's webpage is acceptable. The California Secretary of State website is located at https://businesssearch.sos.ca.gov/.

V. Confidentiality

No Participant shall collaborate on or discuss with any other Participant or potential Bidding strategies, the substance of any Bid(s), including without limitation the price or any other terms or conditions of any Bid(s), or whether PG&E has Selected Bids or not.

All information and documents in Participant's Package that have been clearly identified and marked by Participant as "Proprietary and Confidential" on each page on which confidential information appears shall be considered confidential information. PG&E shall not disclose such confidential information and documents to any third parties except for PG&E's employees, agents, counsel, accountants, advisors, or contractors who have a need to know such information and have agreed to keep such information confidential and except as provided otherwise in this section. In addition, Participant's Package will be disclosed to the IE.

Notwithstanding the foregoing, it is expressly contemplated that the information and documents submitted by Participant in connection with this Solicitation, including Participant's confidential information, may be provided to the CPUC, its staff, and the Procurement Review Group ("PRG"), and established pursuant to D.02-08-071. PG&E retains the right to disclose any information or documents provided by Participant to the CPUC, the PRG, in the advice letter filing or in order to comply with any applicable law, regulation, or any exchange, control area or California Independent System Operator rule, or order issued by a court or entity with competent jurisdiction over PG&E at any time even in the absence of a protective order, confidentiality agreement, or nondisclosure agreement, as the case may be, without notification to Participant and without liability or any responsibility of PG&E to Participant. PG&E cannot ensure that the CPUC will afford confidential treatment to Participant's confidential information, or that confidentiality agreement or orders will be obtained from and/or honored by the PRG, the California Energy Commission, or the CPUC. By submitting a Bid, Participant agrees to adhere and be bound by the confidentiality provisions described in this section.

The treatment of confidential information described above shall continue to apply to information related to Selected Bids.

VI. Procurement Review Group Review

Following completion of the evaluation and ranking of Bids, PG&E will submit the results of the evaluation and its recommendations to its PRG members. PG&E will consider any alternative recommendations proposed by the PRG. PG&E, in its sole discretion, shall determine whether any alternatives proposed by the PRG should be adopted. PG&E has no obligation to obtain the concurrence of the PRG with respect to any Bids.

PG&E assumes no responsibility for the actions of the PRG, including actions that may delay or otherwise affect the schedule for this Solicitation, including the timing of the selection of Bids and the obtaining of Regulatory Approval.

VII. Regulatory Approval

After Agreement execution, PG&E is required to submit executed Agreements to the CPUC for approval via an advice letter filing.

The effectiveness of any executed Agreement is expressly conditioned on PG&E's receipt of final and non-appealable CPUC approval of such Agreement ("Regulatory Approval").

VIII. Dispute Resolution

Except as expressly set forth in this Solicitation Protocol, by submitting a Bid, Participant knowingly and voluntarily waives all remedies or damages at law or equity concerning or related in any way to the Solicitation, the Solicitation Protocol and/or any attachments to the Solicitation Protocol ("Waived Claims"). The assertion of any Waived Claims by Participant may, to the extent that Participant's Package has not already been disqualified, automatically disqualify such Bid from further consideration in the Solicitation.

By submitting a Bid, Participant agrees that the only forums in which Participant may assert any challenge with respect to the conduct or results of the Solicitation is through the Alternative Dispute Resolution ("ADR") services provided by the CPUC pursuant to Resolution ALJ-185, August 25, 2005. The ADR process is voluntary in nature, and does not include processes, such as binding arbitration, that impose a solution on the disputing parties. PG&E will consider the use of ADR under the appropriate circumstances. Additional information about this program is available on the CPUC's website at the following link: www.cpuc.ca.gov/PUBLISHED/Agenda_resolution/47777.htm.

Participant further agrees that other than through the ADR process, the only means of challenging the conduct or results of the Solicitation is a protest to an Advice Letter Filing seeking approval of one or more Agreements entered into as a result of the Solicitation, that the sole basis for any such protest shall be that PG&E allegedly failed in a material respect to conduct the Solicitation in accordance with this Solicitation Protocol, and the exclusive remedy available to Participant in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the Solicitation that the CPUC determines was not previously conducted in accordance with the Solicitation Protocol. Participant expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorney's fees. Unless PG&E elects to do otherwise in its sole discretion during the pendency of such a protest or ADR process, the Solicitation and any related regulatory proceedings related to the Solicitation, will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the Solicitation or PG&E has elected to terminate the Solicitation.

Participant agrees to indemnify and hold PG&E harmless from any and all claims by any other Participant asserted in response to the assertion of a Waived Claim by Participant or as a result of a Participant's protest to an advice letter filing with the CPUC resulting from the Solicitation.

Except as expressly provided in this Solicitation Protocol, nothing herein including Participant's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E. Nothing in this Solicitation Protocol is intended to prevent any Participant from informally communicating with the CPUC or its staff regarding this solicitation.

IX. Termination of the Solicitation-Related Matters

PG&E reserves the right at any time, in its sole discretion, to terminate the Solicitation for any reason without prior notification to Participants and without liability to, or responsibility of, PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the Solicitation may include the assertion of any Waived Claims by a Participant or a determination by PG&E that, following evaluation of the Bids, there are no Bids that meet the requirements of this Solicitation.

PG&E reserves the right to terminate further participation in this process by any Participant, to accept any Bid or to enter into any Agreement, and to reject any or all Bids, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Bids.

In the event of termination of the Solicitation for any reason, PG&E will not reimburse Participant for any expenses incurred in connection with the Solicitation. PG&E shall have no obligation to reimburse any Participants' expenses regardless of whether such Participants' Package is selected, not selected, rejected or disqualified. Unless earlier terminated, the Solicitation will terminate automatically upon the execution of one or more Agreements by Participants with Selected Bids. In the event that no Agreements are executed, then the solicitation will terminate automatically on ***[PG&E to insert date]***.

X. Participants' Representations and Warranties

1. By submitting a Bid and clicking "Yes" to the "Acknowledgment of Protocol" section of the Bid Form, Participant agrees to be bound by the conditions of the Solicitation, and makes the following representations, warranties, and covenants to PG&E, which representations, warranties, and covenants shall be deemed to be incorporated in their entireties into each of Participant's Package. Participant agrees that an electronic signature of a duly authorized representative of Participant shall be the same as delivery of an executed original document for purposes of the Bid Form.

    - Participant has read, understands and agrees to be bound by all terms, conditions and other provisions of this Solicitation Protocol;

    - Participant has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the Solicitation and this Solicitation

Protocol, including the submittal forms and documents listed in this Solicitation Protocol which are posted on the RFO website;

- Participant has obtained all necessary authorizations, approvals and waivers, if any, required by Participant to submit its Bid pursuant to the terms of this Solicitation Protocol and to enter into an Agreement with PG&E;

- Participants' Package complies with all applicable laws;

- Participant has not engaged, and covenants that it will not engage, in any communications with any other actual or potential Participant in the Solicitation concerning this Solicitation, price terms in Participants' Package, or related matters and has not engaged in collusion or other unlawful or unfair business practices in connection with the Solicitation;

- Any Bid submitted by Participant is subject only to PG&E's acceptance, in PG&E's sole discretion; and

- The information submitted by Participant to PG&E in connection with the Solicitation and all information submitted as part of any Bid is true and accurate as of the date of Participants' submission. Participant also covenants that it will promptly update such information with PG&E upon any material change thereto.

2. By submitting a Bid, Participant acknowledges and agrees:

   - That PG&E may rely on any or all of Participant representations, warranties, and covenants in the Solicitation (including any Bid submitted by Participant); and

   - That in PG&E's evaluation of Bids pursuant to the Solicitation, PG&E has the right to disqualify a Participant that is unwilling or unable to meet any other requirement of the Solicitation, as determined by PG&E in its sole discretion.

3. BY SUBMITTING A BID, PARTICIPANT HEREBY ACKNOWLEDGES AND AGREES THAT ANY BREACH BY PARTICIPANT OF ANY OF THE REPRESENTATIONS, WARRANTIES AND COVENANTS IN THESE SOLICITATION INSTRUCTIONS SHALL CONSTITUTE GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH PARTICIPANT, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, AND DEPENDING ON THE NATURE OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE SOLICITATION IN ITS ENTIRETY.

APPENDIX E.2

2020 Bundled RPS Energy Sales Solicitation
Bid Form

2020 Bundled RPS Energy (REC) Sale Solicitation Bid Form

0% Complete

0 of 35 input requirements satisfied

Contact Information	
Bidder Name:	
Bidder Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	
Buyer/Counterparty:	
Buyer/Counterparty Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	

Product & Bid Information	
Product:	Bundled RPS-eligible energy and associated RECs
Delivery Location:	NP15, SP15, and/or ZP26
Payment Index:	Trading Hub Price

Delivery Term 1: 2020	
I am bidding into Delivery Term 1:	<Choose>

Delivery Term 2: 2021	
I am bidding into Delivery Term 2:	<Choose>

Participant's Non-Disclosure Agreement (NDA)	
By submitting an offer, Participant agrees to adhere and be bound by the confidentiality provisions described in the 2020 Bundled RPS Energy (REC) Sale Solicitation Protocol and the Confidentiality Agreement included as Attachment C to the Solicitation Protocol.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Acknowledgement of Protocol	
By selecting "Yes" Participant hereby agrees to the terms of the Solicitation Protocol. Participant acknowledges that any costs incurred to become eligible or remain eligible for the solicitation, and any costs incurred to prepare a bid for this solicitation are solely the responsibility of Participant.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Participant Authorization	
By selecting "Yes" Participant hereby confirms that they are "a duly authorized representative of Participant."	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Attestation	
By providing the electronic signature below Participant hereby attests that all information provided in this Bid Package and in response to this REC Solicitation is true and correct to the best of Participant's knowledge as of the date such information is provided.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

A File Name Must Be Generated

This offer form will not be accepted if the steps outlined below have not been followed!

A new File Name must be generated via the steps below for each offer form submitted. If submitting multiple offer forms, please repeat these steps for each offer form submitted.

These steps will create a unique, correctly formatted name that must be given to this offer form file before it is submitted. If you are submitting multiple offer forms and you employing "Save As" on a form you previouly populated to create a new offer it is essential that a new/different file name be generated for each additional offer form you create.

When you are ready to submit this form…

1) Click this button ►

2) Copy this text ▼ via the button at right and use it AS IS as the name of the file you submit.

3) Once you have named this offer form via the steps above and submitted this form to PG&E keep it unchanged in a secure location where you can refer to it should PG&E have questions. If a PG&E representative contacts you regarding this offer form they will reference the file name.

These instructions must be exercised just prior to actual submission of the form. The file name composed above must be created after you have finalized the rest of the form.

APPENDIX E.3

2020 RPS Form EEI Master Power Purchase and Sale Agreement Short-Term Sales Confirmation

EEI MASTER POWER PURCHASE AND SALE AGREEMENT
SHORT TERM SALES CONFIRMATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY
AND
[**Buyer to insert its full name here in all caps**]

This confirmation ("Confirmation") confirms the transaction ("Transaction") between Pacific Gas and Electric Company, a California corporation, but limited for all purposes hereunder to its electric procurement and electric fuels functions ("Seller" or "Party B"), and [***Buyer to insert its full name, place of formation and type of entity***] ("Buyer" or "Party A"), each individually a "Party" and together the "Parties", effective as of the Execution Date, for the sale and purchase of the Product defined herein.

Except as otherwise expressly stated herein, this Confirmation is subject to, and incorporates by reference with the same force and effect as if set forth herein, all of the terms and provisions of the Parties' EEI Master Power Purchase and Sale Agreement, together with the Cover Sheet [and the amendments and annexes thereto] [***PG&E to identify any amendments or annexes here]***, dated as of [***MM/DD/YYYY***] [***PG&E to insert date in MM/DD/YYYY format***] (collectively, ["Master Agreement"] ["EEI Agreement" ***if no Collateral Annex***]) [, and the corresponding Collateral Annex and Paragraph 10 to the Collateral Annex thereto]. [Such Collateral Annex and Paragraph 10 to the Collateral Annex shall be referred to collectively herein as the "Collateral Annex"]. [The Master Agreement and the Collateral Annex shall be referred to collectively herein as the "EEI Agreement".] The EEI Agreement and this Confirmation shall be referred to collectively herein as the "Agreement."

Capitalized terms used but not defined in this Confirmation shall have the meanings ascribed to them in the EEI Agreement, the RPS (defined herein), or the Tariff (defined herein). If there is a conflict between the terms in this Confirmation and those in the EEI Agreement, this Confirmation shall control.

[PG&E to delete references to the Collateral Annex above if there is no existing Collateral Annex between the Parties]

[Standard contract terms and conditions shown in shaded text are those that "may not be modified" per CPUC Decisions ("D.") 07-11-025; D.10-03-021, as modified by D.11-01-025; and D.13-11-024.]

Seller: Pacific Gas and Electric Company, limited for all purposes hereunder to its electric procurement and electric fuels functions		**Buyer:** [***Buyer to insert its name here***]
Contact Information:	**Name:** Pacific Gas and Electric Company, limited for all purposes hereunder to its electric procurement and electric fuels functions ("Seller" or "Party B")	**Name:** [***Buyer to insert its contact name here***] ("Buyer" or "Party A")
	All Notices: P.O. Box 770000, Mail Code N12E San Francisco, CA 94177 Attn: Senior Manager, Contract Management	**All Notices:** [***Buyer to insert its address for Notices here***] Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***]

	Phone: (415) 973-8660 E-mail: [***PG&E to insert here***]	Email: [***Buyer to insert here***]
	Invoices: Attn: Day-Ahead Scheduling Phone: (415) 973-6222 Email:	**Invoices:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Scheduling: Attn: Day-Ahead Scheduling Phone: (415) 973-6222 Email: DAEnergy@pge.com	**Scheduling:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Payments: Attn: Manager, Contract Settlements Phone: (415) 973-4277 Email:	**Payments:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Wire Transfer: BNK: ABA: ACCT: Duns: Federal Tax ID Number:	**Wire Transfer:** BNK: ABA: ACCT: Duns: Federal Tax ID Number:
	Credit and Collections: **Credit and Collections:** Attn: Manager, Credit Risk Management Phone: (415) 972-5188 Email: PGERiskCredit@pge.com	**Credit and Collections:** **Credit and Collections:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***] **Collateral:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] E-mail: [***Buyer to insert here***]
	Defaults: With additional Notices of an Event of Default or Potential Event of Default to: Pacific Gas and Electric Company 77 Beale Street, Mail Code B30A San Francisco, CA 94105 Attn: Legal Department Email: [***PG&E to insert here***]	**Defaults:** With additional Notices of an Event of Default or Potential Event of Default to: Address: [***Buyer to insert here***] Attn: [***Buyer to insert here***] Email: [***Buyer to insert here***]

	Contract Manager: Attn: Senior Manager, Contract Management Phone: [***PG&E to insert here***] Email: [***PG&E to insert here***]	

ARTICLE 1
COMMERCIAL TERMS

Seller: PACIFIC GAS AND ELECTRIC COMPANY, limited for all purposes hereunder to its electric procurement and electric fuels functions	**Buyer: [Buyer to insert its full name here in all caps]**
Product:	The Product shall consist of Electric Energy and associated Green Attributes from the Project, as further described and subject to the provisions herein.
Project:	All Product sold hereunder shall be generated from one or more facilities, listed in Appendix A to this Confirmation or identified pursuant to Section 8.2 herein, each meeting the requirements set forth in 6.1 (collectively, the "Project"). Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or pursuant to Section 8.2 herein. Buyer shall not be entitled to, and shall not receive, any amount of Green Attributes produced by the Project that is in excess of the Total Quantity. Buyer shall not be entitled to, and shall not receive, any amount of Electric Energy produced by the Project that is in excess of the Energy Quantity.
Quantity:	(a) <u>For Green Attributes</u>: "Total Quantity", with respect to an applicable year, shall be equal to those volumes of Green Attributes specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be conveyed during the Green Attributes Delivery Period to Buyer as provided herein. (b) <u>For Electric Energy</u>: "Energy Quantity", with respect to an applicable year, shall be equal to those volumes of Electric Energy specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be delivered during the Energy Delivery Period to Buyer as provided herein.

Delivery Term Quantity Schedule		
Year	**Green Attributes (MWh)**	**Electric Energy (MWh)**

Energy Price:	The Energy Price shall mean the Index Price for each megawatt-hour (MWh) of Delivered Energy delivered to Buyer under this Agreement.
Green Attributes Price:	The Green Attributes Price shall mean, with respect to an applicable year, that price in dollars for each MWh of Green Attributes conveyed to Buyer under this Agreement, as specified in the table below.

	<table><tr><th>Year</th><th>Green Attributes Price ($)</th></tr><tr><td></td><td></td></tr></table>
Term of Transaction:	Except as otherwise provided herein, the term of the Transaction shall commence upon the Execution Date and shall continue until the end of the Delivery Term and the satisfaction of all other obligations of the Parties under this Agreement ("Term"). This Confirmation, and the Transaction and Term hereunder, shall terminate early in the event of a failure to satisfy the Green Attributes Condition Precedent defined below or as otherwise provided in the Agreement. Termination because of a failure to satisfy the Green Attributes Condition Precedent shall terminate all of the Parties' obligations under the Confirmation as of the Transaction Termination Date as provided in Section 4.2, except for the Parties' confidentiality obligations under Article 9 herein.
Credit Requirements:	(a) This Confirmation's credit requirements for the Electric Energy portion of the Product shall be governed by the EEI Agreement. (b) This Confirmation's credit requirements for the Green Attributes portion of the Product shall apply as specified below: (i) If the EEI Agreement has a Collateral Annex, then the Exposure Amount for the Green Attributes portion of the Product shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (ii) In the event the EEI Agreement does *not* have a Collateral Annex *and* Section 8.2(c), entitled "Collateral Threshold" with respect to "Party B Credit Protection," of the EEI Agreement applies, then the Termination Payment for the Green Attributes portion of the Product to be delivered to Party B as described in Section 8.2(c) of the EEI Agreement shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (c) Section 8.1 of the EEI Agreement, entitled "Party A Credit Protection", and all corresponding provisions of (i) the Cover Sheet to Section 8.1 of the EEI Agreement; and (ii) the Collateral Annex with respect to such Section 8.1 and the applicable provisions thereto of Paragraph 10 to the Collateral Annex do not apply to this Confirmation.
Delivery Term:	The "Delivery Term" shall consist of both the Energy Delivery Period and the Green Attributes Delivery Period.
Energy Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Energy Delivery Period" shall (1) commence as of the later of [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format***] and that date upon which CPUC Approval occurs; and (2) end on the earlier of the conclusion of hour ending 2400 (PPT) on [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format for short-term transaction***] and that date upon which the amount of Electric Energy delivered by Seller satisfies the Energy Quantity.

Green Attributes Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Green Attributes Delivery Period" shall commence on the first day that Seller conveys Green Attributes to Buyer and shall end on that date upon which the amount of Green Attributes conveyed to Buyer satisfies the Total Quantity. Seller shall convey Green Attributes to Buyer in the form of WREGIS Certificates. Seller shall transfer WREGIS Certificates into Buyer's WREGIS account in an amount required to satisfy the Total Quantity.
Delivery Point:	The "Delivery Point" shall be any of the following as selected by Seller in its discretion: NP15, SP15, and/or ZP26. Buyer shall take possession of Electric Energy from the Project at the applicable Delivery Point selected by Seller.
Scheduling Obligations:	Seller, or a qualified third party designated by Seller, shall act as Scheduling Coordinator for the Project. Buyer hereby authorizes Seller, or its third party Scheduling Coordinator designee, to deliver the Electric Energy to the CAISO at the Delivery Point as an agent on Buyer's behalf.
Condition Precedent to the Green Attributes Obligations:	Notwithstanding any other provision of this Confirmation to the contrary, all of the Parties' obligations except for the Parties' confidentiality obligations under Article 9 herein, are conditioned upon (a) Seller's receipt, or the Parties' written waiver, of CPUC Approval as defined below ; and (b) Seller's receipt of the Performance Assurance from Buyer no later than five (5) Business Days following Seller's Notice to Buyer of CPUC Approval (defined below) (collectively, "Green Attributes Condition Precedent").

ARTICLE 2
DEFINITIONS

2.1 "Balancing Authority" has the meaning set forth in the CAISO Tariff.

2.2 "Balancing Authority Area" has the meaning set forth in the CAISO Tariff.

2.3 "Broker or Index Quotes" means quotations solicited or obtained in good faith from (a) regularly published and widely-distributed daily forward price assessments from a broker that is not an Affiliate of either Party and who is actively participating in markets for the relevant Products; or (b) end-of-day prices for the relevant Products published by exchanges which transact in the relevant markets.

2.4 "Business Day" means all calendar days other than those days on which the Federal Reserve member banks in New York City are authorized or required by law to be closed, and shall be between the hours of 8:00 a.m. and 5:00 p.m. Pacific Prevailing Time for the relevant Party's principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.

2.5 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

2.6 "CAISO Grid" has the same meaning as "CAISO Controlled Grid" as defined in the CAISO Tariff.

2.7 "California Renewables Portfolio Standard" or "RPS" means the renewable energy program and policies established by California State Senate Bills 1078, X1 - 2 and 350, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

2.8 "CARB" means the California Air Resources Board or its successor agency.

2.9 "CEC" means the California Energy Commission or its successor agency.

2.10 "Contract Price" means the Energy Price plus the Green Attributes Price.

2.11 "CPUC" means the California Public Utilities Commission or its successor entity.

2.12 "CPUC Approval" means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement from an eligible renewable energy resource for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

For the purpose of this Section 2.12, a CPUC Energy Division disposition which contains such findings, or deems approved an advice letter requesting such findings, shall be deemed to satisfy the CPUC decision requirement set forth above.

Also, for the purpose of this Section 2.12 only, the references therein to "Buyer" shall mean "Seller".

2.13 "Credit Rating" means, with respect to any entity, (a) the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements); or (b) if such entity does not have a rating for its unsecured, senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody's. If the entity is rated by both S&P and Moody's and such ratings are not equivalent, the lower of the two ratings shall determine the Credit Rating. If the entity is rated by either S&P or Moody's, but not both, then the available rating shall determine the Credit Rating.

2.14 "Delivered Energy" means the Electric Energy from the Project that is delivered by Seller to Buyer at the Delivery Point.

2.15 "Electric Energy" means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

2.16 "Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

2.17 "Execution Date" means the latest signature date found on the signature page of this Agreement.

2.18 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under this Agreement, which event or circumstance was not anticipated as of the Execution Date, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (a) the loss of Buyer's markets; (b) Buyer's inability economically to use or resell the Product purchased hereunder; (c) the loss or failure of Seller's supply unless caused by a force majeure event at the Project; or (d) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point; and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the two foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred.

2.19 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

2.20 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHG) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Electric Energy. Green Attributes do not include (i) any Electric Energy, capacity, reliability or other power attributes from the Project; (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation; (iii) fuel-related subsidies or "tipping fees" that

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project.

2.21 "Index Price" means the Trading Hub price (as defined in the CAISO Tariff) associated with the Delivered Energy to the Delivery Point for each applicable hour as published by the CAISO on the CAISO website or any successor thereto, unless a substitute publication and/or index is mutually agreed to by the Parties.

2.22 "Law" means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective after the Execution Date; or any binding interpretation of the foregoing. For the purposes of the definition of "CPUC Approval" in Section 2.12 and Sections 6.1(a), 6.1(b) and 8.3(b) in this Confirmation, the term "law" shall have the meaning set forth in this definition.

2.23 "Letter of Credit" means an irrevocable, non-transferable, standby letter of credit the form of which shall be substantially as contained in Appendix B to this Agreement; provided that, if the issuer is a U.S. branch of a foreign commercial bank, the intended beneficiary may require changes to such form; and the issuer must be a Qualified Institution on the date of delivery of the Letter of Credit to the Secured Party. In case of a conflict of this definition with any other definition of "Letter of Credit" contained in the EEI Agreement or any exhibit or annex thereto, this definition shall supersede any such other definition for purposes of the Transaction to which this Agreement applies.

2.24 "Market Quotation Average Price" means the arithmetic mean of the quotations solicited in good faith from not less than three (3) Reference Market-Makers (as hereinafter defined); provided, however, that the Party obtaining the quotes shall use reasonable efforts to obtain good faith quotations from at least five (5) Reference Market-Makers and, if at least five (5) such quotations are obtained, the Market Quotation Average Price shall be determined by disregarding the highest and lowest quotations and taking the arithmetic mean of the remaining quotations. The quotations shall be based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to each Terminated Transaction. The quote must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. Each quotation shall be obtained, to the extent reasonably practicable, as of the same day and time (without regard to different time zones) on or as soon as reasonably practicable after the relevant Early Termination Date. The day and time as of which those quotations are to be obtained will be selected in good faith by the Party obtaining the quotations and in accordance with the Notice provided pursuant to Section 5.2 of the EEI Agreement, which designates the Early Termination Date. If fewer than three quotations are obtained, it will be deemed that the Market Quotations Average Price in respect of such Terminated Transaction or group of Terminated Transactions cannot be determined. For purposes of this Section 2.24, "Reference Market-Maker" means a leading dealer in the relevant market selected by a Party determining its exposure in good faith from among dealers of the highest credit standing which satisfy all the criteria that such Party applies generally at the time in deciding whether to offer or to make an extension of credit.

2.25 "Notice" means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, or electronic messaging (e-mail). The contacts table of this Confirmation contains the names and addresses to be used for Notices.

2.26 "Qualified Institution" means either a U.S. commercial bank, or a U.S. branch of a foreign bank acceptable to the Beneficiary Party in its sole discretion; and in each case such bank must (i) have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those ratings agencies, and (ii) have assets of at least $10 billion US Dollars.

2.27 "Real-Time Market" has the meaning set forth in the Tariff and shall include any market that CAISO may establish prior to or during the Term that clears at an interval between the Day-Ahead Market and the Real-Time Market.

2.28 "Renewable Energy Credit" or "REC" has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

2.29 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases for delivery at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (a) costs reasonably incurred by Buyer in purchasing such substitute Product; and (b) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or absent a purchase, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

2.30 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not received by Buyer, deducting from such proceeds any (a) costs reasonably incurred by Seller in reselling such Product; and (b) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or absent a sale, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, further, that in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

2.31 "Tariff" means the CAISO Fifth Replacement FERC Electric Tariff and protocol provisions, including any CAISO-published procedures or business practice manuals, as they may be amended, supplemented or replaced (in whole or in part) from time to time.

2.32 "Transactions" as used in the EEI Agreement shall mean the "Transaction" as defined in the preamble above.

2.33 "WREGIS" means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

2.34 "WREGIS Certificate" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

2.35 "WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS.

ARTICLE 3
CONVEYANCE OF ELECTRIC ENERGY AND GREEN ATTRIBUTES

3.1 Seller's Delivery of Electric Energy.

Subject to the terms and conditions of this Agreement, beginning on the first day of the Energy Delivery Period and continuing until the last day of the Energy Delivery Period, Seller shall deliver and sell, and Buyer shall purchase and receive, the Delivered Energy.

3.2 Seller's Conveyance of Green Attributes.

(a) Green Attributes. Subject to the terms and conditions of this Agreement, beginning on the first day of the Green Attributes Delivery Period and continuing until the last day of the Green Attributes Delivery Period, Seller shall convey and sell, and Buyer shall purchase and receive, those Green Attributes associated with the Delivered Energy.

(i) Seller represents and warrants that Seller holds the rights to such Green Attributes from the Project and Seller agrees to convey such Green Attributes to Buyer as included in the delivery of the Product from the Project subject to the terms and conditions of this Agreement.

(ii) As set forth above, Seller shall convey only that amount of Green Attributes required to meet the Total Quantity and shall do so only during the Green Attributes Delivery Period.

(b) The Green Attributes in the amount of the Total Quantity shall be deemed to be conveyed to and received by Buyer under this Confirmation as set forth herein. During the Green Attributes Delivery Period, Seller shall convey to Buyer the Green Attributes associated with the Delivered Energy within: twenty-five (25) Business Days following the occurrence of both (I) the deposit into Seller's WREGIS account of the WREGIS Certificates for the Green Attributes for the applicable Calculation Period; and (II) Buyer's payment of the Monthly Cash Settlement Amount in accordance with Article 5 herein. Seller shall transfer such WREGIS Certificates in an amount equivalent to the Total Quantity to Buyer's WREGIS account such that all right, title and interest in and to the WREGIS Certificates shall transfer from Seller to Buyer.

ARTICLE 4
CPUC FILING AND APPROVAL

4.1 Filing for CPUC Approval.

Within sixty (60) days after the Execution Date, Seller shall file with the CPUC a request for CPUC Approval. Buyer shall use commercially reasonable efforts to support Seller in obtaining CPUC Approval. Seller shall have no obligation to seek rehearing or to appeal a CPUC decision which fails to approve this Confirmation or which contains findings required for CPUC Approval with conditions or modifications unacceptable to either Party. Notwithstanding anything to the contrary in the Confirmation, Seller shall not have any obligation or liability to Buyer or any third party for any action or inaction of the CPUC or other Governmental Authority affecting the approval or status of this Confirmation as a transaction eligible for portfolio content category 1, as defined in California Public Utilities Code Section 399.16(b)(1).

4.2 Termination Right and Transaction Termination Date.

In the event that: (a) the CPUC issues a final and non-appealable order not approving this Agreement in its entirety; (b) the CPUC issues a final and non-appealable order which contains conditions or modifications unacceptable to either Party; or (c) approval by the CPUC has not been received by Seller on or before sixty (60) days from the date on which Seller files for CPUC Approval, then either Party may, in its sole discretion, elect to terminate this Agreement upon Notice to the other Party provided in accordance with Article 10.7 of the EEI Agreement. Such Notice shall become effective one (1) Business Day after its provision. The effective date of the Notice shall constitute the "Transaction Termination Date". Any termination elected and noticed in accordance with this Section 4.2 shall terminate all of the Parties' rights and obligations under the Agreement as of the Transaction Termination Date, except for the Parties' confidentiality obligations under Article 9 herein.

4.3 Effect of Termination.

Any termination properly exercised by a Party under Section 4.2 shall be without liability or obligation, except for the Parties' confidentiality obligations under Article 9 herein, and shall have no effect on the status of the EEI Agreement.

ARTICLE 5
COMPENSATION

5.1 Calculation Period.

The "Calculation Period" shall be each calendar month or portion thereof that Delivered Energy was conveyed to Buyer and for which associated Green Attributes will be transferred to Buyer under this Confirmation as described in Section 3.2(b).

5.2 Monthly Cash Settlement Amount.

Buyer shall pay Seller the Monthly Cash Settlement Amount, in arrears, for each Calculation Period. The "Monthly Cash Settlement Amount" for a particular Calculation Period shall be equal to the sum of (a) plus (b) minus (c), where:

(a) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour; and

(b) equals the Green Attributes Price multiplied by the quantity of Green Attributes (in MWhs) that will be conveyed as described in Section 3.2(b) and that are associated with the Delivered Energy in the Calculation Period; and

(c) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour.

5.3 Payment Date.

Notwithstanding anything to the contrary in Article Six of the EEI Agreement, payment of each Monthly Cash Settlement Amount by Buyer to Seller under this Confirmation shall be due and payable four (4) calendar months following the applicable Calculation Period and on or before the later of: (a) the twentieth (20th) day of the month in which the Buyer receives from Seller an invoice for the Calculation Period to which the Monthly Cash Settlement Amount pertains; and (b) ten (10) days following the date of Buyer's receipt of an invoice issued by Seller for such applicable Calculation Period; provided that, if such payment due date is not a Business Day, then on the next Business Day. Payment to Seller shall be made by wire transfer pursuant to the Notices section of this Agreement.

5.4 Invoices.

The invoice shall include a statement detailing the amount of Delivered Energy, and associated Green Attributes, transferred to Buyer during the applicable Calculation Period. For purposes of this Confirmation, Buyer shall be deemed to have received an invoice upon Buyer's receipt by e-mail of such invoice in PDF format from Seller. Invoices to Buyer shall be sent by email to: **[*Buyer to insert*]**

ARTICLE 6
REPRESENTATIONS, WARRANTIES AND COVENANTS

6.1 Seller's Representations, Warranties, and Covenants.

(a) Seller Representations and Warranties. Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(b) Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(c) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(i) For the avoidance of doubt, the term "contract" as used in the immediately preceding paragraph means this Confirmation.

(ii) For further clarity, the phrase "first delivery" as used in the immediately preceding paragraph means the first date of the Green Attributes Delivery Period.

(d) In addition to the foregoing, Seller warrants, represents and covenants, as of the Execution Date and throughout the Delivery Term, that:

(i) Seller has the contractual rights to sell all right, title, and interest in the Product required to be delivered hereunder;

(ii) Seller has not sold the Product required to be delivered hereunder to any other person or entity;

(iii) Seller is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Confirmation);

(iv) at the time of delivery, all rights, title, and interest in the Product required to be delivered hereunder are free and clear of all liens, taxes, claims, security interests, or other encumbrances of any kind whatsoever;

(v) Seller shall not substitute or purchase any Product from any generating resource other than the Project or the market for delivery hereunder; and

(vi) the facility(s) designated by Seller as the Project and all electrical output from the facility(s) designated as the Project are, or will be, by the first date of the Green Attributes Delivery Period, registered with WREGIS as RPS-eligible.

(e) As of the Execution Date and throughout the Energy Delivery Period, Seller represents, warrants and covenants that the Project meets the criteria in either (A) or (B):

(A) The Project either has a first point of interconnection with a California balancing authority, or a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area; or

(B) The Project has an agreement to dynamically transfer electricity to a California balancing authority.

(f) If and to the extent that the Product sold by Seller is a resale of part or all of a contract between Seller and one or more third parties, Seller represents, warrants and covenants that the resale complies with the following conditions in (i) through (iv) below as of the Execution Date and throughout the Energy Delivery Period:

(i) The original upstream third party contract(s) meets the criteria of California Public Utilities Code Section 399.16(b)(1)(A);

(ii) This Agreement transfers only Electric Energy and Green Attributes that have not yet been generated prior to the commencement of the Energy Delivery Period;

(iii) The Delivered Energy transferred hereunder is transferred to Buyer in real time; and

(iv) If the Project has an agreement to dynamically transfer electricity to a California balancing authority, the transactions implemented under this Agreement are not contrary to any condition imposed by a balancing authority participating in the dynamic transfer arrangement.

6.2 To the extent a change in Law occurs after the Execution Date that causes the representations, warranties, and/or covenants in Section 6.1or this Section 6.2 that continue beyond the Execution Date to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law.

6.3 "Commercially reasonable efforts" as set forth in this Article 6 and as applicable to Seller only shall not require Seller to incur out-of-pocket expenses in excess of twenty-five thousand dollars ($25,000.00) in the aggregate during the Term.

ARTICLE 7
TERMINATION AND CALCULATION OF TERMINATION PAYMENT

In the event this Transaction becomes a Terminated Transaction pursuant to Section 5.2 of the EEI Agreement, then the Settlement Amount with respect to this Transaction shall not be calculated in accordance with the EEI Agreement, but instead shall be calculated as follows:

The Non-Defaulting Party shall determine its Gains and Losses by determining the Market Quotation Average Price for the Terminated Transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts, to obtain the Market Quotation Average Price with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for the Terminated Transaction in a commercially reasonable manner by calculating the arithmetic mean of the quotes of at least three (3) Broker or Index Quotes based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to the Terminated Transaction. Such Broker or Index Quotes must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts to obtain at least three (3) such Broker or Index Quotes with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner by reference to information supplied to it by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information; provided, however, that such third parties shall not be Affiliates of either Party. Only in the event the Non-Defaulting Party is not able, after using commercially reasonable efforts, to obtain such third party information, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner using relevant market data it has available to it internally.

ARTICLE 8
GENERAL PROVISIONS

8.1 **Buyer Audit Rights**

In addition to any audit rights provided under the EEI Agreement, Seller shall, during the Term as may be requested by Buyer, provide documentation (which may include, for example, meter data as recorded by a meter approved by the Project's governing Balancing Authority) sufficient to demonstrate that the Product has been conveyed and delivered to Buyer.

8.2 Facility Identification

Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or by identifying one or more facilities as provided herein. If Seller determines that any Product to be delivered in a calendar month shall be from a facility or facilities other than those in Appendix A, then Seller shall provide Notice to Buyer identifying the facility or facilities that constitute the Project within three (3) Business Days prior to the delivery of Electric Energy from such facility or facilities in such calendar month.

8.3 Governing Law

(a) Notwithstanding any provision to the contrary in the EEI Agreement, the Governing Law applicable to this Agreement shall be as set forth herein. This Section 8.3 does not change the Governing Law applicable to any other confirmation or transaction entered into between the Parties under the EEI Agreement.

(b) Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

For the purposes of Section 8.3(b) above, the words "party" and "parties" shall have the meaning ascribed to them in the preamble of this Confirmation, and the word "agreement" shall mean the term "Agreement" as defined in the preamble of this Confirmation.

ARTICLE 9
CONFIDENTIALITY

9.1 The confidentiality provisions in Section 10.11 of the EEI Agreement shall apply herein, except that each of Buyer and Seller may disclose the following information regarding this Confirmation:

(a) Party names;
(b) Resource(s);
(c) Term;
(d) Project name, location(s), and information in Appendix A;
(e) Capacity of each facility designated as the Project;
(f) The fact that a facility designated as the Project is on-line and delivering;
(g) Delivery Point;
(h) The quantity of Product expected or actually delivered under this Confirmation; and
(i) Information provided by Seller pursuant to Section 8.1 of this Confirmation

9.2 Except for disclosures to comply with any applicable regulation, rule, or order of the CPUC, Federal Energy Regulatory Commission, CEC, or other Governmental Authorities, each Party shall provide Notice of any disclosure made pursuant to this Article 9 to the other Party.

ACKNOWLEDGED AND AGREED TO BY EACH PARTY'S DULY AUTHORIZED REPRESENTATIVE OR OFFICER:

PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, limited for all purposes hereunder to its electric procurement and electric fuels functions.	[**BUYER, (*include place of formation and business type*)**], **by its duly authorized officers**
Signature: ______________________	Signature: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

APPENDIX A to
EEI Master Power Purchase and Sale Agreement
Short Term Sales Confirmation

PROJECT

Name of Facility	Resource	Location	CEC RPS ID	Host Balancing Authority

APPENDIX B

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXX

Date: ***[insert issue date]***

Beneficiary:	Pacific Gas and Electric Company 77 Beale Street, Mail Code B28L San Francisco, CA 94105 Attention: Credit Risk Management	**Applicant:**	[Insert name and address of Applicant]

Letter of Credit Amount: ***[insert amount]***

Expiry Date: ***[insert expiry date]***

Ladies and Gentlemen:

By order of ***[insert name of Applicant]*** ("Applicant"), we hereby issue in favor of Pacific Gas and Electric Company (the "Beneficiary") our irrevocable standby letter of credit No. ***[insert number of letter of credit]*** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. $ ***[insert amount in figures followed by (amount in words)]*** ("Letter of Credit Amount"). This Letter of Credit is available with ***[insert name of issuing bank, and the city and state in which it is located]*** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on ***[insert expiry date]*** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. ***[insert number]*** and stating the amount of the demand; and

2. One of the following statements signed by an authorized representative or officer of Beneficiary:

   A. "Pursuant to the terms of that certain EEI Power Purchase and Sale Agreement (the "Agreement"), dated ***[insert date of the Agreement]***, between Beneficiary and ***[insert name of Seller under the Agreement]*****,** or any Confirmation thereunder or related thereto**,** Beneficiary is entitled to draw under Letter of Credit No. ***[insert number]*** amounts owed by ***[insert name of Seller under the Agreement]*** under the Agreement; or

   B. "Letter of Credit No. ***[insert number]*** will expire in thirty (30) days or less and ***[insert name of Seller under the Agreement]*** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;

3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment hereto for a period of one (1) year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date in case of an interruption of our business as stated below), at our offices at ***[insert issuing bank's address for drawings]***.

All demands for payment shall be made by presentation of original drawing documents and a copy of this Letter of Credit; or by facsimile transmission of documents to ***[insert fax number]***, Attention: ***[insert name of issuing bank's receiving department]***, with original drawing documents and a copy of this Letter of Credit to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at ***[insert phone number]*** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision,* International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit, if they are presented within thirty (30) days after the resumption of our business, and will effect payment accordingly.

The law of the State of New York shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at ***[insert number and any other necessary details]***.

Very truly yours,

[insert name of issuing bank]

By: ______________________________
Authorized Signature

Name: ***[print or type name]***

Title: ***[print or type title]***

[Note: All pages must contain the Letter of Credit number and page number for identification purposes.]

APPENDIX B

FORM OF LETTER OF CREDIT

EXHIBIT A – SIGHT DRAFT

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: $________________________ DATE: __________________________

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF PACIFIC GAS AND ELECTRIC COMPANY THE AMOUNT OF U.S.$________(______________ U.S. DOLLARS)

DRAWN UNDER ***[INSERT NAME OF ISSUING BANK]*** LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: ________________________________
NAME AND TITLE

APPENDIX E.4

2020 Bundled RPS Energy Sales Solicitation Confidentiality Agreement

CONFIDENTIALITY AGREEMENT

This confidentiality agreement ("Confidentiality Agreement") dated as of the last date of signature found at the signature block ("Execution Date") is entered into by and between Pacific Gas and Electric Company, a California corporation, ("PG&E") and ________________ ("Participant"), ***[Participant to insert type of entity]***, each of which may be referred to herein separately as a "Party" or together as the "Parties". ***[Note to Participants: If you have provided a Bid as part of a joint venture or partnership, please insert the names of all parties in interest as Participants.]***

Whereas, each Party ("Provider") may have furnished and is furnishing to the other Party ("Recipient") certain Confidential Information, as defined below, in order to assess Participant's bid to purchase certain product from PG&E as submitted into PG&E's 2020 Bundled Renewables Portfolio Standard ("RPS") Energy Sale Solicitation issued ***[insert date]*** ("Solicitation") pursuant to California Public Utilities Commission ("CPUC") Decision **[insert date]** and the negotiation of an agreement ("Agreement") in connection with the Solicitation, if applicable;

Whereas, it is to the mutual benefit of each Party hereto to enter into this Confidentiality Agreement and provide for the procedure to exchange and protect Confidential Information, as defined below, pursuant to this Confidentiality Agreement;

NOW, THEREFORE, in consideration of Provider's disclosure to Recipient of Confidential Information and other valuable consideration, the Parties agree as follows:

1. Definition of Confidential Information

The term "Confidential Information" shall mean all information that either Party has furnished or is furnishing to the other Party, which with respect to Participant as Provider must in addition be clearly marked "Confidential" (or promptly identified in writing as such when furnished to PG&E in intangible form), in connection with or pertaining to the Solicitation or any Agreement bid thereunder, whether furnished before or after the Execution Date of this Confidentiality Agreement, whether intangible or tangible, and in whatever form or medium provided, and regardless of whether owned by Provider, as well as all information generated by Recipient or its Representatives, as defined below, that contains, reflects, or is derived from such furnished information. "Confidential Information" shall also include information regarding the Parties' bidding and negotiation process, including the status of such process, and potential commercial relationship concerning the Solicitation or any Agreement bid thereunder.

2. Disclosure to Representatives

Recipient agrees that it shall maintain the Confidential Information in strict confidence and that the Confidential Information shall not, without Provider's prior written consent, be disclosed by Recipient or by its affiliates, or their respective officers, directors, partners, employees, agents, or representatives (collectively, "Representatives") in any manner whatsoever, in whole or in part, and shall not be used by Recipient or by its Representatives other than in connection with the Solicitation and the evaluation or negotiation of the Agreement; provided that, PG&E may use Confidential Information, consolidated with other market information and not specifically attributed to the Provider, to analyze or forecast market conditions or prices, for its own internal use or in the context of regulatory or other proceedings. Moreover, Recipient agrees to transmit the Confidential Information only to such of its Representatives who need to know the Confidential Information for the sole purpose of assisting Recipient with such permitted uses, as applicable; provided that, Recipient shall inform its Representatives of this Confidentiality Agreement and secure their agreement to abide in all material respects by its terms. In any event, Recipient shall be fully liable for any breach of this Confidentiality Agreement by its Representatives as though committed by Recipient itself.

3. Nondisclosure

Recipient further agrees that it:

(a) Shall not disclose any Confidential Information provided to it by Provider to any third party for any purpose, except as provided in Section 5 below (or Section 2 above if a Representative is a third party);

(b) Shall not distribute all or any portion of Confidential Information to any Representative for any purpose other than as permitted by Section 2 above; and

(c) Shall destroy or return all such Confidential Information upon Provider's request; provided that, each Party shall have the right to retain one copy of Confidential Information for regulatory compliance or legal purposes, and neither Party shall be obligated to purge extra copies of Confidential Information from electronic media used solely for disaster recovery backup purposes.

4. Exclusions to Confidential Information

For purposes of this Confidentiality Agreement, Confidential Information does not include information that:

(a) Is in the public domain at the time of the disclosure by Provider or is subsequently made available to the general public through no violation of this Confidentiality Agreement by Recipient;

(b) Recipient can demonstrate was at the time of disclosure by Provider already in Recipient's possession and was not acquired, directly or indirectly, from Provider on a confidential basis;

(c) Is independently developed by Recipient without use of or reference to the Confidential Information; or

(d) Is disclosed with the prior written consent of Provider.

5. Required and Permitted Disclosure

Recipient agrees not to introduce (in whole or in part) into evidence or otherwise voluntarily disclose in any administrative or judicial proceeding, any Confidential Information**,** except as required by law or as Recipient may be required to disclose to duly authorized governmental or regulatory agencies ("Required Disclosure"). In the event that Recipient or any of its Representatives becomes subject to a Required Disclosure, Recipient agrees:

(a) To the extent practicable, to use reasonable efforts to notify Provider prior to disclosure and to prevent or limit such disclosure; and

(b) If disclosure of such Confidential Information is required to prevent Recipient from being held in contempt or subject to other legal detriment, to furnish only such portion of the Confidential Information as it is legally compelled to disclose and to exercise its reasonable efforts to obtain an order or other reliable assurance that confidential treatment will be accorded to the disclosed Confidential Information.

After using such reasonable efforts, Recipient shall not be prohibited from complying with the Required Disclosure and shall not be liable to the other Party for monetary or other damages incurred in connection with the Required Disclosure.

In addition to the Required Disclosure, PG&E shall be permitted to disclose Confidential Information as follows: (i) to PG&E's Procurement Review Group ("PRG"), as defined in CPUC Decision 02-08-071 and subject to confidential treatment by PRG members; (ii) to the CPUC (including CPUC staff) under seal for purposes of review (if such seal is applicable to the nature of the Confidential Information), and (iii) to the Independent Evaluator, as defined and specified in the 2020 Bundled RPS Energy Sale Solicitation Protocol ("Protocol"). PG&E shall also be permitted to disclose Participant's Confidential Information in order to comply with (A) any applicable law, regulation, or any exchange or control area rule, or (B) any applicable regulation, rule, or order of the CPUC, California Energy Commission, the California Air Resources Board, or the Federal Energy Regulatory Commission, including any mandatory discovery or data request issued by any of the foregoing entities.

6. No License Rights

This Confidentiality Agreement and any Confidential Information used or disclosed hereunder shall not be construed as granting, expressly or by implication, Recipient any rights by license or otherwise to such Confidential Information or to any invention, patent or patent application, or other intellectual property right, now or hereafter owned or controlled by Provider.

7. Publicity

Subject to Sections 4 and 5, neither Party will disclose any information or make any news release, advertisement, public communication, response to media inquiry or other public statement regarding this Confidentiality Agreement and the Confidential Information disclosed hereunder (including without limitation the potential commercial relationship between the Parties, the inclusion of a bid on PG&E's shortlist of bids, or the status of negotiations) or the performance hereunder or with respect to a bid, without the prior written consent of the other Party.

8. No Future Contracts

Entry into this Confidentiality Agreement and the disclosure of Confidential Information hereunder shall not constitute a bid or acceptance or promise of any future contract or amendment of any existing contract. Each Party shall retain such rights with respect to its own Confidential Information as it had prior to entering into this Confidentiality Agreement. Neither Party shall have any legal obligation with respect to any contemplated transaction because of this Confidentiality Agreement nor any other written or oral expression with respect to any transaction except, in the case of this Confidentiality Agreement, for the matters specifically agreed to herein.

9. No Representation or Warranties

Any Confidential Information exchanged under this Confidentiality Agreement shall carry no warranties or representations of any kind, either expressed or implied, unless specifically expressed per the terms of the Protocol. Recipient shall not rely on the Confidential Information for any purpose other than to make its own evaluation thereof or as provided in the Protocol.

10. Injunctive Relief

Recipient acknowledges and agrees that, in the event of any breach of this Confidentiality Agreement, Provider may be irreparably and immediately harmed and monetary damages may not be adequate to make Provider whole. Accordingly, it is agreed that, in addition to any other remedy to which it may be entitled in law or equity and, with respect to PG&E as Provider any remedy under the Protocol, Provider shall be entitled to an injunction or injunctions (without the posting of any bond and without proof of actual damages) to cease breaches or prevent threatened breaches of this Confidentiality Agreement and/or to compel specific performance of this Confidentiality Agreement, and that neither Recipient nor its Representatives will oppose the granting of such equitable relief if a court finds a breach or threatened breach. Each Party expressly agrees that it shall bear all costs and expenses, including attorneys' fees and costs that it may incur as Provider in enforcing the provisions of this Confidentiality Agreement.

11. Term and Provisions Surviving Termination

This term of this Confidentiality Agreement shall be two (2) years from the Execution Date; provided however, that either Party may earlier terminate this Confidentiality Agreement by giving the other Party thirty (30) days prior written notice of its intention to terminate this Confidentiality Agreement. Any such expiration or termination shall not abrogate either Party's obligations hereunder with respect to Confidential Information received prior to such expiration or termination nor those terms herein relating to the interpretation or enforcement of this Confidentiality Agreement relating to said obligations. Such obligations and terms shall survive for a period of three (3) years from said expiration or termination.

12. No Waiver

Any waiver of any provision of this Confidentiality Agreement, or a waiver of a breach hereof, must be in writing and signed by both Parties to be effective. Any waiver of a breach of this Confidentiality Agreement, whether express or implied, shall not constitute a waiver of a subsequent breach hereof.

13. Binding Nature and Amendment

This Confidentiality Agreement contains the entire understanding between the Parties with respect to Confidential Information received hereunder. No change or modification shall be effective unless made in writing and signed by an authorized representative of each Party. Any conflict between the language of any legend or stamp on any Confidential Information received hereunder, any provision of the Solicitation Protocol, or Agreement relating to Confidential Information provided during the term of this Agreement, on the one hand, and this Confidentiality Agreement, on the other hand, shall be resolved in favor of the language of this Confidentiality Agreement. This Confidentiality Agreement may not be amended or modified except by a written agreement executed by both Parties.

14. Governing Law and Jurisdiction

THIS CONFIDENTIALITY AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA. THE PARTIES AGREE THAT ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATED IN ANY WAY TO THIS CONFIDENTIALITY AGREEMENT SHALL BE BROUGHT SOLELY IN A COURT OF COMPETENT JURISDICTION SITTING IN THE CITY AND COUNTY OF SAN FRANCISCO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY CONSENT TO THE JURISDICTION OF ANY SUCH COURT AND HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF ANY ACTION OR PROCEEDING IN ANY SUCH COURT, ANY OBJECTION TO VENUE WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING AND ANY RIGHT OF JURISDICTION ON ACCOUNT OF THE PLACE OF RESIDENCE OR DOMICILE OF ANY PARTY THERETO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE THE RIGHT TO A JURY TRIAL IN CONNECTION WITH ANY CLAIM ARISING OUT OF OR RELATED TO THIS CONFIDENTIALITY AGREEMENT.

15. Severability

If any provision hereof is unenforceable or invalid, it shall be given effect to the extent it may be enforceable or valid, and such unenforceability or invalidity shall not affect the enforceability or validity of any other provision of this Confidentiality Agreement.

16. Counterparts

This Confidentiality Agreement may be signed in counterparts, each of which shall be deemed an original. This Confidentiality Agreement may be executed and delivered by facsimile or PDF transmission and the Parties agree that such facsimile or PDF transmission execution and delivery shall have the same force and effect as delivery of an original document with original signatures.

17. Notice

Any notice given hereunder by either Party shall be made in writing and shall be effective once delivered, by any of the following means: (a) e-mail, with indication of complete electronic transmission thereof and receipt of a copy sent via certified United States Mail, return receipt requested, as evidenced by a signed delivery receipt; or (b) overnight delivery by a nationally recognized overnight delivery service, as verified by a delivery receipt or signature, addressed as follows:

To Participant: [***TO BE COMPLETED BY EACH PARTICIPANT]***

Name: ________________________
Address: ________________________
Address: ________________________
Facsimile: ______________________
Email: _________________________

To PG&E: Pacific Gas and Electric Company
Electric Supply Department
Attn: RFO Manager
77 Beale Street, (MC B25J)
San Francisco, California 94105
Facsimile: (415) 973-3946
Email: RECSolicitations@pge.com

Either Party may periodically change any address to which notice is to be given it by providing written notice of such change to the other Party.

IN WITNESS WHEREOF, each Party has caused this Confidentiality Agreement to be duly executed and delivered by its proper and duly authorized agent as of the date set forth in submitted Bid Form.

PACIFIC GAS AND ELECTRIC COMPANY	**[PARTICIPANT NAME]**
Signature	Signature
Print Name	Print Name
Title	Title
Date	Date

Appendix F

Framework for Assessing Potential Sales of RPS Volumes

Appendix F – Framework for Assessing Potential Sales of Renewables Portfolio Standard Volumes

This Appendix describes Pacific Gas and Electric Company's ("PG&E") framework (the "Sales Framework") for assessing whether to hold or sell Renewables Portfolio Standard ("RPS") volumes and only applies to RPS sales with deliveries up to two years forward. This Appendix F framework governs only PG&E's sales that are approved as part of the 2019 RPS Plan. For purposes of clarity, Appendix H to this Plan, which governs other sales of Tree Mortality Non-Bypassable Charge Renewable Energy Credits, does not apply to the Bundled RPS Energy Solicitation(s) governed by the 2019 RPS Plan. This Sales Framework will be updated each year as part of the RPS Plan filing. PG&E may therefore annually adjust its methodology and the resulting calculations of volumes for sale.

[redacted]

Determine Volume Limits:

PG&E will use the Sales Framework to establish which bids it will execute, if any, in its Bundled RPS Energy Solicitation(s) governed by the 2019 RPS Plan. Specifically, this Framework establishes [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The Annual Limits and Solicitation Limits will be re-calculated for each solicitation, adjusting for volumes executed in prior solicitations.[3]

- PG&E will target issuing three, with a minimum of two, solicitations per year[4]

- PG&E will utilize the protocol included at Appendix E.1 of this 2019 RPS Plan and will execute sales based on the pro forma sales agreement contained in Appendix E.3 PG&E will show any necessary changes to the pro forma sales agreement in a redline filed with its Advice Letter seeking approval of executed sales agreements.

- PG&E intends to sell all volumes through PG&E-issued solicitations.

- PG&E will consider price offered as the sole quantitative criterion.

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1 These annual RPS compliance targets are those established by the California Public Utilities Commission ("Commission") in relevant decision for each year of each multi-year RPS compliance periods in order to calculate the total Procurement Quantity Requirement for each such compliance period.

2 The annual limits will incorporate the amount of volume that PG&E is able to deliver both contractually and physically.

3 Any recalculation will account for any volume sold in prior solicitations.

4 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations is dependent upon the outcome of prior solicitations and/or changes to PG&E's RPS position.

- PG&E retains the discretion, subject to CPUC review, to decline to accept any offers arising out of a sales solicitation and/or to discontinue any sales solicitation under any circumstances in which there is evidence of market manipulation.

APPENDIX G

Detailed Explanation of PG&E's Least-Cost, Best-Fit Methodology

PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria

I. Introduction

A. Establishment of the Least-Cost, Best-Fit ("LCBF") Process

Decision ("D.") 03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in Renewables Portfolio Standard ("RPS") solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups and the California Public Utilities Commission ("CPUC").

In addition, D.06-05-039 required "each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected."

D.06-05-039 also required each investor-owned utility ("IOU") to hire an Independent Evaluator ("IE") "to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The IE's preliminary report should be provided with the IOU's shortlist, and a final report with the AL for approval of selected bids."

The Scoping Memo for Rulemaking 06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC's Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports ("LCBF Written Report").

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected. D.11-04-030 added that each utility should describe LCBF treatment of congestion, and to certain price data available. Although Pacific Gas and Electric Company's ("PG&E") 2019 RPS Plan does not indicate a need for RPS procurement, PG&E's LCBF protocol may be used in other Request for Offers ("RFO") for mandated procurement or for RPS energy sales.

B. Goal of PG&E's bid evaluation, selection criteria, and processes

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations consistent with the procurement goals set forth in an RFO.

II. Bid Evaluation and Selection Criteria

A. Overview of the Ranking Methodology

PG&E evaluates each bid in terms of the following quantitative and qualitative attributes:

1. Net Market Value
    a. Benefits (Energy, Capacity, Renewable Eneergy Credit, Ancillary Services ("A/S")
    b. Contract Payments
    c. Transmission Network Upgrade Costs (also called a "transmission adder")
    d. Congestion Cost
2. Portfolio-Adjusted Value
    a. RPS Portfolio Need

3. Qualitative factors

Solicited bids are evaluated using the following step-by-step process:

The Net Market Value ("NMV") is computed for each Offer. NMV will be adjusted by other attributes, such as RPS portfolio need, to arrive at the Portfolio-Adjusted Value ("PAV"). After the calculation of PAV is complete, PG&E considers qualitative criteria listed below. The set of highest ranked Offers which allow for a reasonable probability of satisfying PG&E's procurement goal is selected for the Shortlist or contract execution.

1. Market Valuation

a. Overview of the Market Valuation Criterion

Market valuation considers how an Offer's costs compare to its market benefits. Costs include Transmission Network Upgrade Cost, Congestion Cost and Integration Cost as well as contract payments. Benefits include energy, capacity, and ancillary services values. Specifically, Market Valuation computes NMV for each offer as follows:

$$\text{Net Market Value: } R = (E + C) - (P + T + G + I)$$
$$\text{Adjusted Net Market Value: } A = R + S$$

Where
E = Energy Value
C = Capacity Value
P = Post-Time of Delivery ("TOD") Adjusted Power Purchase Agreement ("PPA") Price
T = Transmission Network Upgrade Cost

G = Congestion Costs
I = Integration Costs
S = Ancillary Service Value

Costs and Benefits are each quantified and expressed in terms of levelized dollars per megawatt-hour ("MWh"). NMV is Benefits minus Costs, and is expressed in terms of levelized dollars per MWh.

The calculation of Benefits, Costs, and Market Value is described below.

b. Calculation of Benefits and PPA Costs

Energy benefit (E), for each hour of delivery, is the value of energy delivered at the market energy price at the corresponding Trading Hub (NP15, SP15, ZP26, Palo Verde), adjusted for Losses, plus the market value of the renewable attribute. As-available (or must-take) energy delivery for each hour from an Offer is determined by the hourly generation profile of the Offer. To the extent that the Offer provides dispatchable capacity, the value of the option from the dispatchability will be captured in the energy benefit calculation. The option value calculation depends on the particular characteristics of the dispatchable capacity. If an Offer includes energy storage that allows PG&E to schedule the discharge and charge of the storage, the energy benefit will also include the additional value that PG&E can realize from being able to shift the RPS energy from the Project to more valuable hours given the constraints of the energy storage.

Losses vary by location of the project and are assessed by using the energy price adjusted by losses. The energy price adjusted by losses is obtained as the sum of 1) a Loss Intercept and 2) the product of the corresponding Loss Slope and the hourly LMP of the corresponding Trading Hub as shown below.

$$Energy\ Price\ Adjusted\ for\ Losses = Loss\ Intercept + Loss\ Slope * Trading\ Hub\ LMP$$

The pairs of Loss Intercept and Slope for a project delivered to California Independent System Operator ("CAISO") are provided in Table 1, which are estimated using regression with data from recent years. For example, the energy value for the Central Coast region, after losses, assuming the price at the NP15 trading hub is $100/MWh, is equal to .26+102.3%*(100) = $102.56/MWh. An energy price higher than the trading hub LMP, implies less losses, thus more value associated with a project located in the corresponding load zone. PG&E may further update the Loss Intercept and Slope based on updated market conditions.

Discounted hourly energy benefit is summed across hours of delivery, and summed across years. The total benefit is then scaled by the delivered energy to be expressed in terms of levelized dollars per MWh.

For offers providing Buyer Curtailment, **energy benefit** will include the option value of the difference between the (presumably negative) wholesale market spot price avoided for the Project and PG&E's cost when Buyer Curtailment occurs.

Capacity benefit (C) for Resource Adequacy ("RA"), for year of availability, is the projected monthly quantity of qualifying capacity multiplied by the projected monthly capacity price, discounted and summed across years. To the extent that an Offer provides flexible capacity, the capacity that is expected to count for flexible RA and provide the ISO's must-offer requirement for flexible capacity resources will be evaluated at the projected monthly premium (which can be zero or positive) for flexible RA and then added to the Capacity Benefit. There currently exists significant uncertainty regarding the specifics of generic and flexible RA markets in California. Therefore, the calculation of capacity benefit may evolve as more information is known about market design or as uncertainty lingers.

For an Offer in a location that is projected to contribute to PG&E's satisfaction of a Local Capacity Requirement, the capacity attributable to the Offer may be valued at a premium relative to the value of capacity that satisfies only system needs.

Ancillary Services benefit (S) is assumed to be zero if an Offer doesn't provide any A/S capability. For Offers that provide PG&E the ability to schedule A/S, the incremental benefit of having A/S capability will be captured, not to be double counted with the energy benefit.

PPA Payments (P) are determined by the expected payments under each Offer including associated debt equivalence costs. The PPA Payment for each hour is calculated by multiplying expected delivery quantity by the Offer's price. The Offer's price is the contract price of the Offer multiplied by the applicable TOD factors specified in the RPS Solicitation Protocol. The TOD factors for the 2019 RPS Plan are for informational purposes only. Thus, PPA payments are not TOD adjusted. The hourly PPA Payment is expressed in units of levelized dollars per MWh.

c. Calculation of Transmission Network Upgrade Costs

The Transmission Network Upgrade Costs (T) is the cost, if any, of bringing the power from the generating facility to PG&E's network. PG&E expects to use results from Participants' interconnection studies.

A Present Value Revenue Requirement ("PVRR") is calculated from the Interconnection Study for each evaluated bid. If the Seller is offering an energy-only resource, PG&E will use the reliability network upgrades identified in the interconnection study for calculation of the transmission adder. If the Seller is offering a full deliverability resource, PG&E will use both the reliability network upgrades and delivery network upgrades in the calculation. If the resource does not have an interconnection study, PG&E may rely on a cost cap for transmission upgrades proposed by the Participant.

The PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades is converted into levelized dollars per MWh.[1]

PG&E may take into account on a qualitative basis the additional value for projects that have no transmission risk.

d. Congestion Costs

Congestion cost (G) for each hour is calculated by the multiplication of (1) a Congestion Intercept plus the product of a corresponding Congestion Slope and the LMP of the corresponding Trading Hub, and 2) expected energy delivery.

The Congestion Intercept (or Slope) is obtained by subtracting the LMP Intercept (or Slope) from the Loss Intercept (or Slope). The pairs of LMP Intercept and Slope are estimated using regression with data from recent years. A summary of Congestion Intercepts and Slopes for each load zone in CAISO is included in Table 1. A Congestion Cost greater than zero indicates that generation in the corresponding area serves load outside of the area by congested lines and thus a new generation in the corresponding area is expected to increase the congestion. A zero Congestion Cost implies there is no congestion in the transmission lines connecting the area. A Congestion Cost less than zero indicates that loads in the corresponding area are served by the constrained transmission line(s) and thus a new generation in the area may reduce congestion. A project delivered to Palo Verde would be evaluated with Congestion Cost of 0. PG&E may update the Congestion Cost Intercepts and Slopes as market prices change.

[1] Sellers offering full capacity offers may specify when full capacity is to begin and as a result, costs will be reflected accordingly in the PVRR calculation.

TABLE 1
AVERAGE CONGESTION AND LOSS INTERCEPTS AND SLOPES[2]

			Loss for E		Congestion for G		LMP for E-G	
	Descriptive Names	CAISO APNodes	Intercept	Slope	Intercept	Slope	Intercept	Slope
1	Central Coast	PGCC	0.26	102.3%	-0.40	1.1%	0.66	101.3%
2	East Bay	PGEB	0.13	103.2%	0.03	-1.2%	0.10	104.4%
3	Fresno	PGF1	-0.70	105.8%	-2.05	4.9%	1.34	100.9%
4	Geysers	PGFG	-0.10	103.0%	0.26	-1.8%	-0.35	104.8%
5	Humboldt	PGHB	1.73	102.0%	-3.48	5.8%	5.21	96.2%
6	Kern	PGKN	-0.01	102.5%	-0.76	4.1%	0.75	98.3%
7	North Bay	PGNB	-0.02	103.3%	0.12	-0.9%	-0.15	104.2%
8	North Coast	PGNC	-0.28	102.1%	-0.48	3.1%	0.20	99.0%
9	North of Path 15	PGNP	-0.39	101.5%	0.17	-0.4%	-0.56	101.9%
10	Peninsula	PGP2	0.06	104.2%	0.00	-0.7%	0.06	104.9%
11	South Bay	PGSB	0.10	103.7%	-0.01	-0.3%	0.11	104.0%
12	San Francisco	PGSF	0.28	105.0%	-0.13	-0.4%	0.41	105.5%
13	Sierra	PGSI	-0.29	101.5%	0.25	0.4%	-0.54	101.1%
14	Stockton	PGST	-0.11	102.5%	0.31	-0.8%	-0.43	103.2%
15	ZP26	PGZP	-0.05	103.4%	-0.97	4.7%	0.92	98.7%
16	SCE Core	SCEC	-0.16	102.6%	-0.05	0.6%	-0.12	102.1%
17	SCE Northeast	SCEN	-0.12	100.5%	-0.50	2.7%	0.38	97.8%
18	SCE West	SCEW	-0.10	104.4%	-0.20	-5.0%	0.10	109.4%
19	SCE High Desert	SCHD	-0.27	101.2%	-0.54	3.0%	0.27	98.2%
20	SCE Low Desert	SCLD	0.35	98.6%	-1.75	10.4%	2.10	88.2%
21	SCE Northwest	SCNW	-0.02	101.9%	-0.51	2.7%	0.49	99.2%
22	San Diego	SDG1	-0.16	104.6%	-0.21	-5.0%	0.05	109.6%
23	Valley Electric Association	VEA	0.08	99.8%	-1.34	7.4%	1.42	92.5%

Overall locational value of the project delivered to CAISO should be assessed by looking at the LMP Intercepts and Slopes provided in Table 1. LMP Intercept and Slope for a project delivered to Palo Verde will be 0 and 1, respectively. The pair of Intercept and Slope implies the relative value of 1 MWh in each load zone compared with the corresponding Trading Hub (NP15, SP15, ZP26, or Palo Verde) price. Higher LMP resulted from combined intercept and slope effect implies higher overall locational value.

[2] Intercepts and Slopes shown are simple averages of those for each calendar month and hour of day. Contract valuations use disaggregated values for each calendar month and hour of day. There are 24 estimated regressions per calendar month.

e. Integration Costs

The renewable integration cost adder ("RICA") is calculated using the methodology adopted in D.14-11-042. Renewable integration cost is used in the derivation of Net Market Value per Section 1.a of this document.

The RICA is calculated as the sum of two cost components: 1) variable costs; and 2) fixed costs.

The variable cost component is set at $4/MWh for wind and $3/MWh for solar.

The fixed cost component is calculated as the product of two parameters: 1) PG&E's internal/confidential projection of a monthly premium (which can be zero or positive) for flexible RA expressed as $/kW-month; and 2) the monthly increase (or decrease) in the need for flexible RA associated with one megawatt ("MW") of installed capacity of wind or solar ("Contribution to Flexible Capacity Needs") expressed as MW of flex capacity needed/MW of wind or solar capacity.

The Contribution to Flexible Capacity Needs is determined in the following way:

1. Obtain the hourly aggregate system profile for load, wind, and solar.[3]
2. Calculate the hourly three hour net-load ramp for each hour of the year.[4]
3. Identify the maximum three hour net-load ramp for each month, and determine the relative contributions from load, wind, and solar to that ramp.
4. Determine the monthly increase ("or decrease") in the need for flexible capacity associated with one MW of installed capacity of wind and solar. This is determined based on the contribution of wind / solar in step 3 and the total installed capacity of wind / solar in the system. For example, if there is 5,000 MW of installed wind and wind's contribution to the maximum three hour net-load ramp in July is 500 MW, then wind's contribution to flexible capacity need is 500 MW / 5,000 MW, or 0.1 MW per 1 MW of installed wind. In this example, 0.1 MW would be the Contribution to Flexible Capacity Needs attributed to a bid for wind generation expected to deliver in that month.

For 2019, PG&E has calculated the Contribution to Flexible Capacity Needs using the four steps above and hourly data from the 2014 Long-Term Procurement Plan ("LTPP") Trajectory Scenario[5]. The maximum (single hour) wind / solar output from these 2014 LTPP hourly data is used to estimate the total installed capacity for wind / solar in

[3] Consistent with the CAISO Flexible Capacity Study, the solar PV and solar thermal components are combined. (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf).

[4] Consistent with the CAISO Flexible Capacity Study, this is the three hour contiguous ramp starting in a given hour of the year, where net-load is defined as load minus wind minus solar.

[5] The hourly data can be obtained from the results of the CAISO's 2014 LTPP Production Cost runs. To help parties access this information, PG&E is also providing these publicly available hourly profiles on its website at www.pge.com/rfo under 2014 Renewables RFO.

the system. The resulting Contribution to Flexible Capacity Needs for solar and wind are presented in Table 2 below. These numbers may be updated based on supply and demand information adopted in the most recent Integrated Resource Plan.

TABLE 2
CONTRIBUTION TO FLEXIBLE-RA REQUIREMENT PER 1 MW OF INSTALLED CAPACITY (MW)

Month	Solar	Wind
JAN	0.52	0.12
FEB	0.75	0.09
MAR	0.63	0.15
APR	0.78	0.13
MAY	0.66	0.01
JUN	0.58	0.07
JUL	0.58	0.04
AUG	0.61	0.05
SEP	0.78	0.20
OCT	0.66	0.02
NOV	0.59	0.00
DEC	0.63	0.20

f. Market Valuation for Offers With Storage

PG&E evaluates the market value from dispatchable storage bundled in an Offer for its ability to (1) shift renewable energy to more valuable hours, (2) provide A/S from stored energy and storage capacity, and (3) provide flexible RA.

PG&E solves for the charge, discharge and A/S schedules that would maximize the value from the project starting from the generation profile without using the energy storage, and the storage constraints provided by the Seller. In order to maximize the spot market value from the project given the assumed market prices for energy and A/S, PG&E will use an optimization technique to obtain the best time and amount to charge, discharge and provide A/S capacity. The spot market value consists of the revenue from energy to be delivered to the grid (the sum of energy that is directly generated from the renewable resource and the energy discharged from storage) and the revenue of A/S capacity to be provided, net of the variable cost from operating. Depending on the energy and A/S prices for a given time period, it may be better to provide A/S, charge renewable energy, discharge stored energy, or do nothing from storage. The Energy Value, A/S Value and PPA Costs in Net Market Value are computed from the assumed market prices as well as the optimized charge, discharge, generation, and A/S schedules.

For A/S, PG&E asks bidders to specify capability, ramp rates and operating ranges for providing Regulation Up and Down, Spinning Reserve ("Spin") and Non-spinning Reserves ("Non-spin"). When optimizing the schedules, PG&E makes sure that the A/S schedules are within the operating ranges provided and that there is enough energy and storage capacity available. For valuation purposes, PG&E will assume that the value from providing Non-spin in addition to the Spin is negligible because the price for Non-spin is never higher than price for a similar Spin product. PG&E may include future CAISO A/S products such as flexible ramping product in an optimization to estimate their value if PG&E anticipates that there could be significant incremental value.

Dispatchable storage components that can follow CAISO's day-ahead and real-time dispatch instructions and thus allow PG&E to provide economic bids are expected to count towards meeting PG&E's requirement for flexible RA. Due to the uncertainty about the counting rules that will govern co-located storage components, PG&E will estimate Effective Flexible Capacity for renewable offers with storage as a function of MW size and discharge duration of the energy storage component. The calculation of capacity benefit may evolve as more information is known about market rules. The flexible RA Value will be included in the Capacity Value of the Net Market Value.

2. **Portfolio Adjusted Value**

PAV adjustments reflect PG&E's portfolio position and the value to PG&E's portfolio of a purchase or sale.

a. **RPS Portfolio Need**

PG&E will consider how an Offer contributes to PG&E's overall portfolio need for RPS energy. For a delivery year in which PG&E's portfolio (augmented by the offer) is projected to have lower or higher than targeted RPS-eligible energy, then the PAV Adjustment for the Offer's RPS-eligible energy may be adjusted to a higher or lower value to aid in meeting PG&E's RPS eligible energy targets.

This RPS Portfolio Need adjustment is not duplicative of the Energy Value component of Net Market Value.

Thus, Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio is long.

3. **Qualitative Factors**

PG&E may consider qualitative factors including but not limited to:

- Project location in PG&E's service territory
- Project viability: As part of its qualitative assessment of project viability, PG&E will calculate a project viability score using the most recent version of the Project Viability Calculator adopted by the California Public Utilities Commission

- Impact on disadvantaged communities
- Water use and impact on water quality
- Contribution to state biomass goals
- Contribution to storage targets
- Mark-up of term sheet or PPA
- Contract tenor
- Counterparty concentration
- Technology diversity
- Previous experience with counterparty
- Safety

APPENDIX H

Framework for the Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation

Appendix H – Framework for the Tree Mortality Non-Bypassable Charge Bundled Renewable Portfolio Standard Energy Sale Solicitation

This Appendix is included in PG&E's Renewable Energy Procurement Plan (the "RPS Plan") in order to describe its framework for the sale of Renewable Energy Credits ("REC") associated with certain Renewables Portfolio Standard ("RPS")-eligible biomass generation contracts (the "TM RECs"), in compliance with Ordering Paragraph 4 of California Public Utilities Commission ("Commission") Decision ("D.") 18-12-003. The Appendix contains the following:

- A summary of D.18-12-003's requirements with respect to the sale of specific RECs
- The framework that PG&E will use in order to comply with D.18-12-003 if TM Contracts are extended

This Appendix H framework governs only PG&E's Tree Mortality Non-Bypassable Charge ("TM NBC") Bundled RPS Energy Sale Solicitation. For purposes of clarity, Appendix F to this Plan, which governs other sales of RPS-eligible products, does not apply to the TM NBC Bundled RPS Energy Sale Solicitation except as specifically incorporated by reference in this Appendix H.

I. Decision Summary

On December 21, 2018 the Commission issued D.18-12-003 establishing a methodology for calculating a non-bypassable charge for costs associated with certain tree mortality biomass energy procurement. The non-bypassable charge will recover the net costs of the mandated biomass energy procurement intended to address California's tree mortality crisis. Of particular relevance to this RPS Plan, the Decision requires that PG&E establish a value for the TM RECs by making them available for sale.[1]

II. Compliance Requirements

With regard to the sale of the TM RECs, the Decision orders PG&E to:

- Make available for sale the TM RECs associated with its tree mortality-related procurement contracts required by Resolution (Res.) E-4770 and Res.E-4805 as soon as possible after the effective date of the Decision;[2]
- File any executed sales for the TM RECs associated with its tree mortality-related procurement contracts via Tier 1 advice letters so long as it (1) utilizes the Commission-approved RPS Sales pro forma agreement and (2) shows modifications via a comparison document;[3]

[1] D.18-12-003, pp. 25-26 (Ordering Paragraph ("OP") 3).
[2] *Id.*, pp. 25-26 (OP 3).
[3] *Ibid.*

- Repeat this process if its tree mortality contracts are extended;[4] and
- Update its final, conforming version of its 2018 RPS Plan to conform to the REC sales requirements set forth in D.18-12-003.[5]

As part of a separate Advice Letter filing, PG&E is required to design and implement the TM NBC, in which it must deduct the appropriate REC values from the total costs of its TM contracts.[6]

III. PG&E's TM NBC Bundled RPS Energy Sales Framework (Solicitation #2: For TM Contract Extensions, if needed)

As of June 5, 2019, PG&E is expecting to complete its initial TM NBC Bundled RPS Energy Sales Soclitiation prior to adoption of this 2019 RPS Plan. That initial solicitation was conducted pursuant to the TM NBC Bundled RPS Energy Sales Framework approved as part of PG&E's 2018 RPS Plan.

To comply with the Decision, PG&E will launch a second TM NBC Bundled RPS Energy Sale Solicitation to make available for sale the TM RECs associated with any new tree-mortality contracts or extensions pursuant to Section 8388 of the California Public Utilities Code. PG&E will use the solicitation protocol in Appendix E.1, making any necessary modifications prior to solicitation launch to conform to this framework. PG&E will also make necessary modifications to its Commission-approved pro forma sales agreement in Appendix E.3 to conform to this framework and to address issues raised in specific negotiations with counterparties. Consistent with the Decision, PG&E will file any executed sales of TM RECs via Tier 1 Advice Letter and show modifications to the approved pro forma agreement via a comparison document. PG&E will engage an Independent Evaluator ("IE") to provide oversight of the TM NBC Bundled RPS Energy Sale Solicitation process. The IE's report will be included in the Tier 1 Advice Letter filed following the TM NBC Bundled RPS Energy Sale Solicitation.

PG&E will value TM RECs based upon the result of the TM NBC Bundled RPS Energy Sale Solicitation and deduct that amount from the TM NBC. In the event that the TM NBC Bundled RPS Energy Sale Solicitation does not result in a sale of any TM RECs, PG&E will not use the unsold TM RECs for compliance and the value deducted from the TM NBC will be $0.[7]

To the extent that a contract with a third-party results from a TM NBC Bundled RPS Energy Sale Solicitation and the third-party defaults on the contract prior to expiration resulting in termination of the contract, PG&E will expeditiously conduct another TM NBC Bundled RPS Energy Sale Solicitation for the remaining term of the original agreement, provided that PG&E

[4] *Ibid.*
[5] *Id.*, p. 27 (OP 4).
[6] *Id.*, pp. 25-26 (OP 3), p. 30 (OP 11).
7 D.18-12-003 provides in OP 3: "If the RECs are not purchased, then the value deducted shall be $0 and no load-serving entity may use the REC for compliance purposes." While D.18-12-003 requires PG&E to use a $15.04/MWh price if a REC "was offered for sale in the past, not sold, and then used by the IOU for compliance purposes," the use of the phrase "in the past," which does not appear in a similar framework for TM RA sales set forth in the Decision, makes clear that going forward, unsold RECs have no compliance value. See *id.*, pp. 12-13 (describing REC sales framework); pp. 18-19 (describing RA sales framework).

determines a subsequent solicitation would not take longer than the remaining term of original agreement, and value the remaining RECs in the TM NBC based upon the result of that Solicitation. PG&E will elect to use any TM NBC RECs that are generated but cannot be transferred due to the default of the original counterparty for its own RPS compliance and value the RECs in the TM NBC at the same price executed in the original third-party agreement until a new contract for the remaining term goes into effect and begins delivering.

If PG&E later determines that modifications to this framework are necessary, including changes resulting from any new tree-mortality contracts or extensions pursuant to Section 8388 of the California Public Utilities Code, it will file a motion to update the RPS Plan with an updated framework.

The following subsections provide additional details on the TM NBC Bundled RPS Energy Sale Solicitation structure.

A. PG&E's Tree Mortality Biomass Contracts Subject to the TM NBC[7]

Facility Name	Contract Capacity (MW)	Initial Energy Delivery Date	Expected Delivery End Date
Burney Forest Products	29	11/1/2017	10/31/2022
Wheelabrator Shasta	34	12/2/2017	12/1/2022
Woodland	25	03/01/2010	02/29/2020

B. Product Structure

Product Structure for TM NBC Bundled RPS Energy Sale Solicitation	
Product	• Bundled RPS-energy and associated RECs from PG&E's TM PPAs listed in the table above[8]
Pricing	• Energy – settled at the market index price[9] • REC – fixed price
Delivery Term	• Solicitation #1: Residual term of the tree mortality contracts prior to any extensions (< 5 years) • Solicitation #2 (if needed): Any extended terms of tree mortality contracts executed pursuant to Section 8388 of the California Public Utilities Code (up to 5 years)[10]
Quantity	• Unit-specific - Buyer receives future full energy and REC output of the underlying tree mortality contract
Agreement	• Utilize the Commission-approved RPS sales pro forma agreement (executed contract filed as part of Tier 1 AL in both clean and redline to shows changes to the pro forma agreement)[11]

[7] Any facilities that receive contract extensions pursuant to California Public Utilities Section 8388 would be sold through a second TMNBC Bundled RPS Energy Sale solicitation following those contract extensions. Implementation of Section 8388 may add to and otherwise modify the list of facilities referenced in this table.
[8] D.18-12-003, p. 26 (OP 3, bullet 1).
[9] *Ibid.*
[10] *Id.*, p. 26 (OP 3, bullet 4).
[11] *Id.*, p. 26 (OP 3, bullet 2).

C. Evaluation Criteria

Quantitative – Select bids based on price (highest price in $/MWh)
Qualitative – Consistent with qualitative criteria defined in Appendix F.1 to this RPS Plan (the Bundled RPS Solicitation Protocol).

[redacted]

APPENDIX I

Glossary of Acronyms and Abbreviations

TABLE OF ACRONYMS

Acronym	Full Name
2019 RPS Plan	Draft 2019 Renewables Portfolio Standard Plan
A.	Application
AB	Assembly Bill
ADR	Alternative Dispute Resolution
AL	Advice Letter
ALJ	Administrative Law Judge
A/S	Ancillary Services
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Bioenergy Renewable Auction Mechanism
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPI	Consumer Price Index
CPUC or Commission	California Public Utilities Commission
D.	Decision
DA	Direct Access
DAC-GT	Disadvantaged Communities Green Tariff
DACs	disadvantaged communities
DSOD	Division of Safety of Dams
EE	energy efficiency
EEI	Edison Electric Institute
ESP	Electric Service Provider
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
GEP	Guaranteed Energy Production
GHG	greenhouse gas
GTSR	Green Tariff Shared Renewables
GWh	gigawatt-hour
ID&WA	Irrigation District and Water Agency
IDWA	Irrigation District Water Authority
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
IRP	Integrated Resources Plan
ITC	Investment Tax Credit

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
LCBF	least-cost, best-fit
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MEC	Marginal Energy Costs
MMoP	Minimum Margin of Procurement
MW	megawatt
MWh	Megawatt-hour
NMV	Net Market Value
NPV	Net Present Value
OIR	Order Instituting Rulemaking
O&M	operations and maintenance
OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
PAV	Portfolio Adjusted Value
PCC	portfolio content category
PCIA	Power Charge Indifference Adjustment
PEL	Procurement Expenditure Limitation
PG&E	Pacific Gas and Electric Company
POR	Plan of Reorganization
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PQRs	Procurement Quantity Requirements
PRG	Procurement Review Group
PSP	Preferred System Portfolio
PTC	Production Tax Credit
PTO	Participating Transmission Owner
Pub. Util. Code	Public Utilities Code
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PV RAM	Photovoltaic Program - RAM
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
Res.	Resolution
RFO	Request for Offer
RICA	renewable integration cost adder
RNS	Renewable Net Short
RPS	Renewables Portfolio Standard
SB	Senate Bill
SONS	stochastically-optimized net short
TM NBC	Tree Mortality Non-Bypassable Charge
TOD	Time of Delivery
UOG	Utility-Owned Generation
VMOP	Voluntary Margin of Procurement
WREGIS	Western Renewable Energy Generation Information System
YCWA	Yuba County Water Agency

APPENDIX J

Informational-Only TOD Factors

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.22	1.13	1.09	1.10	1.19	1.37	1.63	1.58	1.08	0.65	0.42	0.37	0.36	0.40	0.53	0.86	1.44	2.19	2.43	2.16	1.95	1.78	1.56	1.35
2	1.11	1.01	0.97	0.99	1.11	1.33	1.61	1.38	0.77	0.31	0.12	0.08	0.08	0.14	0.26	0.50	1.01	1.89	2.35	2.17	1.93	1.70	1.48	1.26
3	1.04	0.91	0.86	0.86	0.93	1.10	1.34	1.18	0.58	0.13	0.01	0.00	0.00	0.00	0.01	0.08	0.32	0.90	1.62	2.06	1.96	1.73	1.49	1.24
4	0.94	0.79	0.73	0.71	0.78	0.97	1.21	0.77	0.20	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.43	1.13	1.86	2.06	1.76	1.50	1.20
5	1.00	0.82	0.74	0.73	0.80	1.00	0.95	0.47	0.12	0.01	0.00	0.00	0.00	0.00	0.03	0.15	0.42	0.77	1.29	1.83	2.17	1.92	1.58	1.26
6	0.94	0.81	0.73	0.72	0.79	0.98	0.80	0.44	0.18	0.08	0.07	0.09	0.13	0.23	0.40	0.64	0.96	1.23	1.55	1.89	2.29	1.95	1.55	1.21
7	1.10	1.01	0.94	0.92	0.98	1.11	1.10	0.82	0.54	0.38	0.39	0.51	0.68	0.91	1.15	1.41	1.77	2.20	2.46	2.80	2.99	2.09	1.63	1.34
8	1.14	1.03	0.97	0.95	1.00	1.15	1.28	1.01	0.66	0.44	0.42	0.56	0.74	0.98	1.21	1.44	1.69	1.96	2.28	3.11	2.79	2.06	1.62	1.35
9	1.11	1.01	0.96	0.93	0.97	1.11	1.32	1.13	0.69	0.39	0.31	0.39	0.51	0.70	0.92	1.18	1.43	1.68	2.20	2.74	2.28	1.84	1.53	1.29
10	1.13	1.01	0.95	0.93	0.97	1.09	1.31	1.30	0.79	0.37	0.20	0.18	0.21	0.30	0.46	0.69	1.04	1.49	2.17	2.21	1.93	1.73	1.53	1.31
11	1.11	1.05	1.02	1.04	1.10	1.24	1.40	1.13	0.71	0.41	0.31	0.28	0.30	0.38	0.59	0.94	1.54	2.06	2.20	1.94	1.76	1.58	1.41	1.24
12	1.21	1.13	1.09	1.10	1.17	1.31	1.52	1.45	1.07	0.74	0.56	0.50	0.47	0.53	0.69	1.04	1.65	2.24	2.32	2.04	1.86	1.69	1.51	1.35

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.21	1.13	1.08	1.04	1.05	1.10	1.28	1.19	0.56	0.18	0.07	0.06	0.05	0.06	0.12	0.43	1.22	1.99	2.25	2.04	1.83	1.69	1.52	1.30
2	1.11	1.00	0.95	0.93	0.96	1.03	1.21	0.84	0.26	0.02	0.00	0.00	0.00	0.00	0.00	0.06	0.60	1.72	2.19	2.03	1.83	1.63	1.44	1.21
3	1.01	0.86	0.81	0.77	0.80	0.90	1.03	0.68	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.65	1.47	1.93	1.85	1.63	1.42	1.19
4	1.00	0.83	0.73	0.69	0.70	0.81	0.87	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.90	1.73	1.95	1.69	1.43	1.16
5	0.99	0.77	0.69	0.64	0.67	0.78	0.47	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.35	0.97	1.66	2.04	1.81	1.48	1.17
6	0.97	0.83	0.74	0.70	0.72	0.80	0.41	0.07	0.00	0.00	0.00	0.00	0.02	0.03	0.07	0.20	0.52	0.90	1.36	1.77	2.15	1.85	1.49	1.17
7	1.12	1.02	0.94	0.88	0.89	0.95	0.74	0.26	0.07	0.03	0.05	0.10	0.17	0.34	0.59	0.91	1.26	1.68	2.13	2.51	2.69	1.97	1.59	1.30
8	1.15	1.01	0.96	0.90	0.91	0.99	0.97	0.41	0.10	0.04	0.04	0.09	0.19	0.37	0.60	0.93	1.29	1.60	1.90	2.43	2.38	1.92	1.56	1.30
9	1.10	0.98	0.91	0.86	0.87	0.94	1.05	0.61	0.13	0.02	0.02	0.04	0.09	0.19	0.39	0.73	1.07	1.43	1.92	2.33	2.04	1.72	1.46	1.25
10	1.14	1.01	0.95	0.91	0.91	0.98	1.10	0.94	0.25	0.04	0.00	0.00	0.00	0.01	0.06	0.21	0.61	1.25	1.96	2.03	1.79	1.62	1.46	1.28
11	1.12	1.03	0.99	0.98	1.00	1.05	1.13	0.70	0.25	0.06	0.01	0.01	0.02	0.06	0.22	0.62	1.37	1.89	2.05	1.82	1.66	1.52	1.36	1.21
12	1.21	1.12	1.08	1.06	1.07	1.12	1.26	1.16	0.67	0.34	0.18	0.14	0.12	0.14	0.31	0.72	1.48	2.04	2.18	1.91	1.76	1.64	1.49	1.34

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.26	1.18	1.13	1.14	1.21	1.36	1.61	1.54	0.97	0.45	0.22	0.18	0.17	0.22	0.37	0.76	1.43	2.25	2.52	2.21	1.97	1.80	1.59	1.38
2	1.17	1.08	1.03	1.04	1.14	1.33	1.58	1.32	0.61	0.15	0.04	0.03	0.04	0.05	0.12	0.39	0.98	1.90	2.40	2.20	1.95	1.72	1.52	1.32
3	1.11	0.98	0.92	0.91	0.97	1.12	1.33	1.14	0.45	0.04	0.00	0.00	0.00	0.00	0.00	0.03	0.23	0.85	1.63	2.08	1.98	1.74	1.52	1.30
4	1.02	0.86	0.79	0.77	0.82	0.98	1.19	0.68	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.32	1.12	1.87	2.06	1.77	1.52	1.26
5	1.00	0.81	0.72	0.69	0.76	0.95	0.84	0.26	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.15	0.53	1.18	1.79	2.14	1.89	1.55	1.26
6	1.01	0.88	0.79	0.76	0.82	0.99	0.76	0.31	0.06	0.01	0.01	0.01	0.03	0.06	0.13	0.31	0.68	1.05	1.47	1.90	2.41	1.97	1.57	1.27
7	1.17	1.08	1.00	0.97	1.02	1.14	1.10	0.74	0.36	0.17	0.13	0.19	0.33	0.54	0.83	1.14	1.55	2.06	2.47	3.09	3.65	2.23	1.67	1.39
8	1.23	1.12	1.06	1.03	1.06	1.19	1.30	0.98	0.52	0.23	0.17	0.25	0.40	0.64	0.92	1.21	1.53	1.91	2.51	4.50	3.69	2.24	1.68	1.42
9	1.22	1.13	1.08	1.05	1.07	1.18	1.36	1.15	0.64	0.25	0.13	0.16	0.25	0.46	0.70	1.01	1.32	1.65	2.53	3.93	2.83	1.99	1.60	1.38
10	1.24	1.13	1.07	1.05	1.07	1.17	1.35	1.32	0.76	0.26	0.07	0.04	0.06	0.13	0.29	0.56	0.99	1.49	2.42	2.50	2.09	1.81	1.60	1.40
11	1.20	1.15	1.12	1.13	1.18	1.29	1.42	1.13	0.65	0.29	0.17	0.14	0.17	0.27	0.50	0.93	1.57	2.26	2.45	2.10	1.85	1.65	1.47	1.32
12	1.30	1.22	1.18	1.19	1.24	1.35	1.54	1.46	1.05	0.65	0.45	0.38	0.37	0.45	0.64	1.06	1.70	2.47	2.59	2.20	1.97	1.77	1.58	1.43

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.26	1.18	1.13	1.08	1.08	1.12	1.27	1.17	0.47	0.08	0.04	0.03	0.02	0.04	0.06	0.36	1.22	2.01	2.27	2.05	1.83	1.70	1.54	1.35
2	1.17	1.07	1.02	0.99	1.00	1.05	1.21	0.80	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.04	0.57	1.73	2.20	2.04	1.83	1.64	1.47	1.28
3	1.08	0.94	0.88	0.84	0.86	0.93	1.04	0.64	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.62	1.49	1.94	1.85	1.65	1.45	1.25
4	1.07	0.90	0.81	0.75	0.75	0.83	0.86	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.90	1.74	1.95	1.70	1.45	1.22
5	0.99	0.76	0.67	0.60	0.62	0.71	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.85	1.62	1.99	1.77	1.46	1.17
6	1.02	0.87	0.78	0.72	0.72	0.80	0.36	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.25	0.68	1.26	1.77	2.20	1.85	1.50	1.21
7	1.19	1.09	1.01	0.94	0.94	0.98	0.75	0.21	0.02	0.00	0.00	0.01	0.02	0.08	0.27	0.59	1.01	1.56	2.05	2.59	2.96	2.04	1.62	1.35
8	1.22	1.09	1.04	0.98	0.97	1.04	1.01	0.39	0.05	0.00	0.00	0.00	0.02	0.11	0.30	0.63	1.06	1.48	1.91	2.76	2.64	1.98	1.60	1.36
9	1.22	1.10	1.04	0.99	0.98	1.04	1.13	0.67	0.11	0.00	0.00	0.00	0.01	0.06	0.20	0.54	0.96	1.39	2.01	2.71	2.24	1.80	1.53	1.34
10	1.24	1.13	1.08	1.03	1.03	1.07	1.17	1.00	0.24	0.03	0.00	0.00	0.00	0.00	0.00	0.14	0.58	1.26	2.05	2.13	1.86	1.67	1.52	1.37
11	1.21	1.14	1.10	1.08	1.09	1.12	1.19	0.75	0.21	0.02	0.00	0.00	0.01	0.02	0.16	0.64	1.40	1.97	2.16	1.90	1.72	1.58	1.43	1.29
12	1.30	1.22	1.18	1.16	1.16	1.19	1.31	1.20	0.66	0.27	0.13	0.09	0.07	0.10	0.28	0.76	1.53	2.14	2.30	1.99	1.83	1.70	1.56	1.42

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.28	1.20	1.15	1.15	1.21	1.34	1.57	1.51	0.95	0.40	0.17	0.13	0.13	0.17	0.32	0.75	1.43	2.33	2.66	2.30	2.01	1.81	1.61	1.40
2	1.20	1.11	1.06	1.06	1.14	1.32	1.55	1.31	0.59	0.12	0.05	0.03	0.04	0.06	0.11	0.38	1.01	1.92	2.48	2.25	1.97	1.73	1.54	1.35
3	1.15	1.02	0.96	0.95	0.99	1.12	1.31	1.12	0.44	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.23	0.88	1.67	2.13	2.00	1.75	1.53	1.33
4	1.08	0.93	0.86	0.82	0.86	0.99	1.17	0.69	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.36	1.18	1.89	2.09	1.78	1.54	1.31
5	1.08	0.90	0.80	0.76	0.81	0.97	0.86	0.28	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.56	1.24	1.81	2.18	1.90	1.57	1.31
6	1.09	0.95	0.85	0.82	0.87	1.01	0.79	0.32	0.04	0.00	0.00	0.00	0.01	0.03	0.08	0.22	0.61	1.03	1.51	2.02	2.65	2.03	1.59	1.31
7	1.22	1.12	1.05	1.01	1.04	1.14	1.11	0.75	0.33	0.12	0.06	0.08	0.17	0.38	0.67	1.01	1.48	2.05	2.68	3.81	4.81	2.46	1.71	1.42
8	1.25	1.13	1.07	1.03	1.06	1.17	1.27	0.96	0.45	0.14	0.07	0.09	0.20	0.41	0.72	1.06	1.42	1.89	2.76	5.65	4.71	2.39	1.69	1.43
9	1.19	1.10	1.04	1.00	1.02	1.12	1.29	1.07	0.50	0.11	0.02	0.03	0.07	0.20	0.47	0.82	1.20	1.58	2.66	4.64	3.10	2.00	1.58	1.36
10	1.21	1.10	1.03	1.00	1.01	1.11	1.28	1.24	0.65	0.13	0.00	0.00	0.00	0.02	0.13	0.39	0.88	1.44	2.47	2.59	2.11	1.79	1.57	1.37
11	1.17	1.11	1.07	1.08	1.12	1.23	1.35	1.06	0.52	0.17	0.08	0.06	0.07	0.13	0.36	0.84	1.52	2.29	2.52	2.12	1.83	1.62	1.44	1.29
12	1.26	1.17	1.13	1.13	1.17	1.28	1.47	1.39	0.95	0.49	0.29	0.23	0.22	0.29	0.50	0.98	1.65	2.52	2.68	2.22	1.96	1.73	1.55	1.39

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.28	1.20	1.15	1.10	1.09	1.11	1.25	1.16	0.45	0.07	0.03	0.02	0.02	0.03	0.07	0.35	1.23	2.03	2.31	2.07	1.84	1.71	1.55	1.38
2	1.21	1.10	1.05	1.02	1.01	1.05	1.20	0.81	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.05	0.63	1.73	2.22	2.05	1.84	1.65	1.49	1.31
3	1.12	0.99	0.93	0.88	0.89	0.95	1.04	0.66	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.64	1.52	1.95	1.85	1.65	1.47	1.29
4	1.13	0.97	0.87	0.81	0.79	0.85	0.87	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.98	1.76	1.97	1.71	1.48	1.28
5	1.07	0.86	0.76	0.68	0.68	0.75	0.41	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.94	1.64	2.01	1.79	1.49	1.24
6	1.09	0.95	0.85	0.79	0.77	0.83	0.40	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.20	0.67	1.30	1.86	2.36	1.88	1.52	1.26
7	1.24	1.13	1.05	0.98	0.97	1.00	0.78	0.21	0.02	0.00	0.00	0.01	0.00	0.03	0.14	0.45	0.91	1.60	2.07	2.85	3.37	2.14	1.64	1.39
8	1.25	1.12	1.06	1.00	0.98	1.03	1.00	0.38	0.03	0.00	0.00	0.00	0.00	0.02	0.16	0.46	0.94	1.44	1.98	3.19	2.96	2.04	1.61	1.39
9	1.19	1.07	1.00	0.94	0.93	0.97	1.05	0.58	0.05	0.00	0.00	0.00	0.00	0.00	0.06	0.33	0.82	1.31	2.00	2.87	2.28	1.78	1.50	1.32
10	1.22	1.10	1.04	0.98	0.97	1.00	1.09	0.92	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.46	1.21	2.02	2.12	1.83	1.64	1.49	1.34
11	1.18	1.10	1.06	1.03	1.03	1.05	1.11	0.65	0.12	0.00	0.00	0.00	0.00	0.01	0.07	0.54	1.34	1.95	2.15	1.88	1.69	1.55	1.40	1.26
12	1.26	1.17	1.13	1.10	1.09	1.12	1.23	1.12	0.54	0.17	0.05	0.03	0.03	0.04	0.19	0.66	1.48	2.12	2.30	1.98	1.80	1.66	1.52	1.38

APPENDIX K

Redline Showing Changes in Final, Conforming 2019 RPS Plan Dated January 29, 2020 Compared to Draft 2019 RPS Plan Dated June 21, 2019

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL, CONFORMING~~DRAFT~~ 2019 RENEWABLE ENERGY PROCUREMENT PLAN

JANUARY 29, 2020~~JUNE 21, 2019~~

CONFIDENTIAL VERSION

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LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its ~~Draft~~ Final, Conforming 2019 Renewables Portfolio Standard ("RPS") Plan ("2019 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Commission in the *Assigned Commissioner And Assigned Administrative Law Judge's Ruling Identifying Issues And Schedule Of Review For 2019 Renewables Portfolio Standard Procurement Plans* (the "2019 RPS Plan Ruling").[1] PG&E's 2019 RPS Plan begins with summaries of the key changes from the 2018 RPS Plan, identifies key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the other specific requirements identified in the 2019 RPS Plan Ruling and other Commission decisions and statutes.[2]

1. Summary of Key Updates

This Section describes the most significant changes between PG&E's Final 2018 RPS Plan and its Draft 2019 RPS Plan as filed on June 21, 2019. A complete redline of the ~~Draft~~ Final, Conforming 2019 RPS Plan against PG&E's Draft~~Final~~ 2019~~8~~ RPS Plan is included as Appendix K~~J~~. The table below provides a list of key differences between the 2018 and 2019~~two~~ RPS Plans:

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[1] 2019 RPS Plan Ruling, filed April 19, 2019 in Rulemaking ("R.") 18-07-003, p. 28 (Ordering Paragraph ("OP") 1. PG&E's Final, Conformed RPS Plan contains limited revisions and additions ordered by Decision ("D.") 19-12-042.

[2] *See* 2019 RPS Plan Ruling, pp. 3-24, Appendix B (providing a template for retail sellers to use in drafting their respective RPS Plans). *See also* ~~Decision ("D.")~~D. 18-12-003, OP 3 (requiring PG&E to include a Framework for Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation in its RPS Plan; Public Utilities Code ("Pub. Util. Code") § 2837 (requiring PG&E's RPS Plan to address energy storage).

TABLE 1-1
SUMMARY OF CHANGES

Reference	Area of Change	Summary of Change and Explanation and Justification
Section 10 and Appendices E and F	RPS Sales Framework, Sales Confirm, and Sales Solicitation Protocol	Updated to take into account market and regulatory changes. Specifically, PG&E is updating its RPS Sales Framework that guides its evaluation of RPS sales opportunities, its Form Confirmation for Short-Term RPS Sales, and its Sales Solicitation Protocol for use in the 2019 RPS Plan cycle.
Section 10.C.1 and Appendix J	Informational-Only Time of Delivery ("TOD") Factors	In its decision approving the 2018 RPS Plans, the Commission required PG&E to provide proposed informational-only TOD factors.[a] PG&E filed this proposal in R.18-07-003 jointly with the other investor-owned utilities ("IOUs") on May 29, 2019. The proposal stated that PG&E would include the informational-only TOD factors in each subsequent RPS Plan filing. Subsequently, D.19-42-042 approved the methodology and ordered TOD factors be updated in the final 2019 RPS plans. Accordingly, PG&E ~~is providing~~ provides a description of ~~its~~ informational-only TOD ~~proposal~~ factors, and ~~a link to the proposed information-only TOD~~ attaches those TOD factors as Appendix J.~~data in this Draft 2019 RPS Plan. These are subject to Commission approval through the pending stakeholder process~~.

TABLE 1-1
SUMMARY OF CHANGES
(CONTINUED)

Reference	Area of Change	Summary of Change and Explanation and Justification
Former Appendices C (Deleted in Draft 2019 RPS Plan)	Stochastic Modeling Variability	As part of PG&E's ongoing efforts to streamline the RPS Plan and to focus the plan on outcomes, PG&E is eliminating this Appendix as an unnecessary level of detail.

(a) D.19-02-007, p. 118 (OP 17).

2. Executive Summary—Summary of Key Issues

2.1 PG&E Has No Current Need for Additional RPS Resources, Although Foreseeable Future Events Could Significantly Change That Need

PG&E is currently well-positioned to meet its RPS compliance requirements. Based on its existing RPS portfolio, demand forecasts, and RPS sales assumptions for planning purposes, PG&E does not project to have incremental physical need[3] for RPS resources until at least 2029. This RPS need year moves beyond 2033 (the "optimized

3 "Incremental physical need," as used in this RPS Plan, describes a situation in which actual deliveries from RPS resources in a given year or compliance period are less than the corresponding RPS interim target or compliance period requirement. Where PG&E has an incremental physical need, excess volumes of RPS procurement carried forward from past years may be used in part to meet any applicable RPS compliance target.

need year") assuming that PG&E applies volumes of RPS procurement above the requirements from past years ("Bank") once it has a physical need.[4,5,6]

However, PG&E's RPS need is subject to considerable uncertainty, including the following:

1. The Commission's review of portfolio optimization in the recently-initiated Phase 2 of the Power Charge Indifference Adjustment ("PCIA") reform proceeding[7] may result in changes to PG&E's RNS position if the Commission orders sales or allocation of PG&E's existing RPS portfolio.
2. Due to PG&E's bankruptcy,[8] PG&E will be developing a restructuring proposal pursuant to Chapter 11 of the United States Bankruptcy Code.[9] For purposes of this 2019 RPS Plan, PG&E assumed that its existing RPS contracts will continue in effect until expiration. Specifically, as part of its restructuring, PG&E will develop a Plan of Reorganization ("POR") that may assume or reject certain contracts, including RPS contracts entered into prior to the bankruptcy filing. PG&E has not decided on the

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4 PG&E's planning assumptions for future additional RPS sales and RPS bank optimization are included in PG&E's Alternate Renewable Net Short ("RNS") provided in Appendix A.2.

5 In prior versions of its RPS Plan, PG&E has redacted its RPS need year, consistent with the May 21, 2014, Administrative Law Judge's ("ALJ") Ruling on RNS issued in R.11-05-005, pages 5 and 24, which established confidentiality rules associated with portfolio optimization. PG&E is waiving this confidentiality in this limited instance in order to allow for public transparency concerning PG&E's proposals to manage its RPS portfolio and concerning PG&E's need for incremental mandated procurement. In doing so, PG&E reserves the right to redact its need year and similar portfolio optimization information in future versions of its RPS Plan. The ability to redact future need is particularly critical when PG&E expects a near-term net short position.

6 Assuming both the maximum volume of sales proposed in the this RPS Plan cycle and additional planned future RPS sales forecasted in PG&E's RNS are executed and approved, PG&E projects that it would have an incremental RPS procurement need after [redacted], after application of its Bank.

7 R.17-06-026.

8 Nothing in this RPS Plan shall be deemed to constitute an assumption of any contract or a waiver or modification of the Debtors' rights to assume, assume and assign, or reject any contract pursuant to the federal bankruptcy code.

9 PG&E's federal bankruptcy proceeding commenced with its January 29, 2019 Chapter 11 bankruptcy filing at the United States Bankruptcy Court, Northern District of California, Case Nos. 19-30088-DM and 19-30089-DM.

assumption or rejection of any pre-petition RPS contracts at the time of this 2019 RPS Plan filing. To the extent an approved POR results in changes to PG&E's RPS portfolio, the associated volumes of deliveries would correspondingly change PG&E's forecast of deliveries and the RNS.

3. Expected increases in customers switching to service from Community Choice Aggregators ("CCA") and generating their own electricity have resulted in dramatic decreases in the IOUs' bundled retail sales projections. As retail sales decrease, the quantity of RPS energy required for PG&E to meet its RPS obligation falls, resulting in a decreased need for new RPS resources.
4. This 2019 RPS Plan assumes the current RPS law remains unchanged and that the Commission does not exercise its authority to raise the RPS requirements for retail sellers. However, legislation enacted after this date and actions taken in the Commission's RPS proceeding can change these inputs.

2.2 PG&E Proposes Not to Hold a Voluntary Solicitation to Buy RPS Products During the 2019 RPS Plan Cycle

Given its current RPS compliance position, PG&E is proposing not to hold a voluntary annual RPS solicitation to buy incremental RPS products during the 2019 RPS Plan cycle. PG&E will seek Commission approval to procure any incremental RPS products during this RPS Plan cycle, other than amounts resulting from the mandated programs referenced below. In the event that PG&E decides to hold a 2019 RPS solicitation to procure incremental RPS products, or to execute bilateral contracts for incremental RPS procurement, PG&E will first seek permission from the Commission in a manner consistent with the Commission's Rules of Practice and Procedure.

Although many factors, including those described above, could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be more than adequate to ensure compliance with near-term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs during the 2019 RPS Plan cycle (which is expected to occur during the calendar year 2020).[10]

2.3 PG&E Plans to Continue to Sell RPS Volumes During the 2019 RPS Plan Cycle

In response to load departure and PG&E's resulting long RPS position, PG&E plans to manage its RPS portfolio to meet the needs of its bundled customers through continued offers to sell RPS volumes during the 2019 RPS Plan cycle. PG&E proposes to pursue short-term RPS sales during the 2019 RPS Plan cycle for deliveries in 2020 and 2021.

Pursuant to its approved 2019~~8~~ RPS Plan, PG&E plans to issue 2-3 solicitations for short-term sales of RPS products during 2019. PG&E has used, and will continue to use, its RPS Sales Framework to assess short-term sales opportunities. PG&E is updating the RPS Sales Framework as part of this 2019 RPS Plan and intends to use the revised RPS Sales Framework, if approved, to target issuing three, with a minimum of two, short-term sales solicitations in 2020.[11]

The goal of PG&E's RPS Sales Framework is to prudently manage PG&E's portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program and preserving optionality for the outcome of the PCIA Phase 2 proceeding. If the market conditions support sales at the highest levels allowed under

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10 Mandated RPS programs include the Renewable Market Adjusting Tariff ("ReMAT"), the Bioenergy Market Adjusting Tariff ("BioMAT"), and any new or extended biomass contracts pursuant to Senate Bill ("SB") 901. The ReMAT program is currently suspended due to litigation, and the Commission has issued a new Order Instituting Rulemaking ("OIR") to consider further implementation of the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA"), which will consider adoption of a new mandate to procure from RPS-eligible facilities that are Qualifying Facilities ("QF") under federal law. *See generally* R.18-07-017. In addition, while it will not directly impact PG&E's RNS, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

11 Additional detail on PG&E's planned sales solicitations is described in Section 10.

the proposed revisions to the RPS Sales Framework, the incremental volumes of sales would be approximately [redacted] gigawatt-hours ("GWh") in 2020 and [redacted] GWh in 2021 based on the RNS table in Appendix A.2. This compares to PG&E's maximum annual sales volume of [redacted] GWh under the approved 2018 RPS Plan. The actual volumes of sales executed and approved in the 2019 RPS Plan cycle will be incorporated into PG&E's RNS calculations going forward and included in future RPS Plans.

2.4 PG&E Opposes Procurement Mandates That Result in Unnecessary and/or Unreasonable Costs for Its Bundled Customers

Despite PG&E's absence of need for additional RPS resources, PG&E is continuing in 2019 to procure required RPS-eligible volumes through mandated procurement programs, such as the BioMAT program. In 2018, for example, PG&E held 12 auctions/solicitations[12] to fulfill mandated program requirements, despite being granted approval by the Commission to not hold an RPS solicitation due to lack of RPS need.

Wherever consistent with law, PG&E will continue to oppose new RPS procurement mandates, seek to suspend existing RPS procurement mandates, and oppose any changes to existing RPS procurement mandates that would require PG&E to conduct additional RPS procurement. In general, PG&E believes that no RPS procurement should be mandated without a clear demonstration of need.

Even if PG&E had near-term RPS need, PG&E would still not support expansion of existing mandated programs or additional new mandated programs. Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-

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[12] PG&E has held bi-monthly auctions for ReMAT since November 1, 2013 (until the program was suspended at the end of 2017, as further described below) and for BioMAT since February 1, 2016. PG&E also held one PV RAM solicitation in 2018.

neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

PG&E continues to be concerned about the cost burden that procurement mandates place on bundled customers and will seek to ensure all customers, both bundled and departed load, equitably bear the costs of additional and existing mandates. Mandated procurement through Bioenergy Renewable Auction Mechanism ("BioRAM"), BioMAT, ReMAT, and the Photovoltaic Program - RAM ("PV RAM") benefits all customers and thus all customers should pay their equitable share of those costs.

Finally, PG&E is open to the concept under discussion in the State Legislature regarding the establishment of a state entity that would be a central buyer for purposes of providing a backstop to ensure that all entities meet their RPS obligations and to procure resources of statewide benefit.

2.5 PG&E Will Continue to Comply with the RPS and Manage Its RPS Portfolio During Bankruptcy

PG&E remains committed to supporting California's clean energy goals, including the RPS, during its restructuring process under Chapter 11 of the United States Bankruptcy Code. As demonstrated by this RPS Plan, PG&E continues to manage its RPS portfolio to achieve compliance in a least-cost, best-fit ("LCBF") manner for its customers. As noted above, PG&E's RPS portfolio may change as a result of its bankruptcy restructuring.

3. Summary of Recent Legislative and/or Regulatory Changes

The following section summarizes key legislative and regulatory developments since PG&E's Final, Conforming 2018 RPS Plan[13] that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the implementation of SB 237;[14]

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13 Discussions on past legislative and regulatory changes (SB 100, SB 350, BioRAM) can be found in PG&E's Final, Conforming 2018 RPS Plan.

14 SB 237, Stats. 2018, Ch. 600 (Hertzberg).

(2) the implementation of SB 100;[15] (3) the implementation of SB 901[16] and BioRAM; (4) the approved Diablo Canyon Retirement Joint Proposal Application; and (5) the pending PCIA reform proceeding at the Commission.

3.1 Implementation of SB 237

SB 237, signed by Governor Brown on September 20, 2018, increases the participation cap for the State's Direct Access ("DA") program by 4,000 GWh statewide. The Commission initiated R.19-03-009 to implement SB 237 on March 21, 2019. On June 3, 2019, the Commission issued D.19-05-043 and determined that the earliest enrollment date for the expansion is January 1, 2021.[17] The apportionment of the 4,000 GWh will occur over two years and will be split in half and apportioned evenly to customers on the 2019 waitlist and on the upcoming 2020 waitlist. PG&E's apportionment of ~1,900 GWh will also be split between the 2019 and 2020 waitlist.

3.2 Implementation of SB 100

On September 10, 2018, Governor Brown signed SB 100, known as the 100 Percent Clean Energy Act of 2018. SB 100 increases the statutory RPS requirements to 44 percent by the end of 2024; 52 percent by the end of 2027; and 60 percent by 2030 and thereafter. PG&E's quantitative analysis in this 2019 RPS Plan, including its RNS tables, reflects these increased targets. Separately, SB 100 adopts a statewide policy that 100 percent of California's retail sales must come from RPS-eligible and zero-carbon resources by 2045. The Commission issued a Proposed Decision on May 22, 2019 to implement revisions to the RPS Procurement Quantity Requirements ("PQRs")[18] for years beginning in 2021. The Proposed Decision may be

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15 SB 100, Stats. 2018, Ch. 312 (De León).

16 SB 901, Stats. 2018, Ch. 626 (Dodd).

17 Note: D.19-05-043 was issued after the DA modeling was completed for the 2019 RPS Plan. As such, the model underlying this Draft 2019 RPS Plan assumes DA expansion would begin in 2020.

18 The PQR for any given multi-year RPS compliance period reflects the total volume of RPS-eligible procurement required in order to achieve compliance with the entire compliance period RPS requirement.

considered for adoption by the Commission, at the earliest, at the June 27, 2019 meeting. The straight-line methodology adopted by the Proposed Decision for determining the PQRs after 2020 is consistent with the modeling assumptions and methodologies used in this 2019 RPS Plan.

3.3 Implementation of SB 901 and BioRAM

SB 901, signed by Governor Brown on September 21, 2018, requires the IOUs to seek to extend the delivery terms of RPS-eligible biomass contracts that meet certain feedstock and other requirements. The Commission issued Resolution ("Res.") E-4977 on February 6, 2019, which amends the BioRAM Program pursuant to SB 901 and requires PG&E to seek additional procurement from certain BioRAM and other biomass contracts pursuant to criteria of California Pub. Util. Code Section 8388. PG&E has executed and submitted for Commission approval an amendment with one of its BioRAM counterparties to comply with some of the requirements established by Res.E-4977 and SB 901. PG&E continues to negotiate with counterparties that own RPS-eligible biomass facilities that meet certain feedstock and other requirements to comply with each of its remaining obligations under Res.E-4977 and SB 901. The Tree Mortality Non-Bypassable Charge D.18-12-003 determined that deliveries from BioRAM contracts will not be used for RPS compliance. As such, deliveries from eligible biomass facilities under SB 901 will not be reflected in PG&E's RNS tables for the purposes of RPS compliance.

3.4 Diablo Canyon Retirement Joint Proposal Application

On August 11, 2016, PG&E and the Joint Parties[19] filed an Application requesting Commission approval of the retirement of Diablo Canyon nuclear power plant. The Commission issued D.18-01-022 on January 16, 2018, approving PG&E's proposal to retire Diablo Canyon, stating the Commission's intent to avoid greenhouse

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19 Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility.

gas ("GHG") emissions increase from Diablo Canyon's retirement, and that the need for replacement procurement should be addressed in the Integrated Resource Plan ("IRP") proceeding. On September 19, 2018, Governor Brown signed SB 1090[20] that would, among other things, require the Commission to ensure the IRPs filed by retail sellers avoid any increase in GHG emissions as a result of retiring the Diablo Canyon nuclear power plant. Finally, in D.19-04-040, the Commission ordered that all Load-Serving Entities ("LSEs") serving load within PG&E's service area include in its subsequent IRP filing a section describing its plan to address the retirement of the Diablo Canyon Generation Plant.

3.5 OIR to Review, Revise, and Consider Alternatives to the PCIA

The Commission issued an OIR to Review, Revise, and Consider Alternatives to the PCIA on June 29, 2017 (the PCIA OIR).[21] PG&E is committed to developing PCIA reform solutions that treat all customers fairly and equally and that support California's clean energy goals.

On October 11, 2018 the Commission issued D.18-10-019 modifying the PCIA methodology. D.18-10-019 determined that a second phase of the proceeding would be opened in order to further define details around the PCIA True-Up, Prepayment of PCIA, IOU Portfolio Optimization, and various other implementation items. On February 1, 2019 the Commission issued a scoping memo in R.17-06-026 directing the parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission (the "Phase 2 Scoping Memo").

The working group most likely to have a significant impact on PG&E's RPS planning and RNS position is Working Group Three, which is focused on portfolio optimization. Parties are considering various methodologies to optimize the RPS portfolio of the large IOUs, including management of the IOU RPS Bank. Accordingly, the outcome of Phase 2 of the PCIA rulemaking could have a material impact on

20 SB 1090, Stats. 2018, Ch. 561 (Monning).

21 See R.17-06-026.

PG&E's RPS need. Pursuant to the procedural schedule established in the Phase 2 Scoping Memo, the Commission plans to issue a decision regarding portfolio optimization by the second quarter of 2020.

4. Assessment of RPS Portfolio Supplies and Demand

A core component of PG&E's overall RPS planning framework is an assessment of PG&E's portfolio need, or lack thereof, for incremental RPS resources. This component has been well established and refined over time and remains largely consistent between this and the previous PG&E RPS Plan filings and is described in detail in this section.

As PG&E continues to find lack of incremental procurement need in recent planning cycles, PG&E has developed and added an RPS Sales component to its overall planning framework. As highlighted in the Summary of Key Updates, PG&E has further revised this RPS Sales component since the 2018 RPS Plan filing and is providing a full description of the changes in Section 10 of this Plan.

4.A. Portfolio Supply and Demand

4.A.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's RPS targets. Under existing law,[22] PG&E is required through 2030 to retire sufficient numbers of Renewable Energy Credits ("RECs") from RPS-eligible products to meet the following RPS requirements:

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[22] Compliance period requirements shown below are based on D.11-12-020 and D.16-12-040, which implemented the targets established by SB 2(1X) and SB 350, respectively. PG&E is assuming, for purposes of this 2019 RPS Plan, that the Commission will implement the SB 100 revised targets in the same "straight-line" manner as it implemented prior versions of the statutory RPS targets. A Proposed Decision implementing SB 100 in a manner consistent with this assumption is pending in R.18-07-003 but will not be acted upon prior to filing of this Draft 2019 RPS Plan.

- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (27.0% * 2017 retail sales) + (29.0% * 2018 retail sales) + (31.0% * 2019 retail sales) + (33.0% * 2020 retail sales);
- 2021-2024: A percentage of the combined bundled retail sales that is consistent with the following formula: (35.8% * 2021 retail sales) + (38.5% * 2022 retail sales) + (41.3% * 2023 retail sales) + (44.0% * 2024 retail sales);
- 2025-2027: (46.7% * 2025 retail sales) + (49.3% * 2026 retail sales) + (52.0% * 2027 retail sales); and
- 2028-2030: (54.7% * 2028 retail sales) + (57.3% * 2029 retail sales) + (60.0% * 2030 retail sales).

Based on preliminary results presented in Appendix A.2, PG&E delivered 38.9 percent of its power from RPS-eligible renewable sources in 2018.

As described more fully in Section 8 and reported in the current RNS calculations in Appendix A.2, PG&E is well-positioned to meet its RPS compliance requirements through the fifth compliance period (2025-2027) and does not project to have incremental physical need for RPS resources until at least 2029. Additionally, based on PG&E's existing portfolio, under the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter, PG&E projects that it would have an incremental RPS procurement need after 2033, assuming the additional RPS sales forecasted in PG&E's Alternate RNS provided in Appendix A.2 are executed and approved and its Bank is applied to meet its RPS needs.[23]

PG&E's RNS is subject to future regulatory and legislative changes, including portfolio changes ordered as part of the ongoing PCIA OIR. PG&E's RPS position will be updated annually to reflect any sales of RPS volumes.

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23 Assuming both the maximum volume of sales proposed in this RPS Plan cycle and additional planned future RPS sales forecasted in PG&E's RNS are executed and approved, PG&E projects that it would have incremental RPS procurement need after [redacted].

4.A.2. Supply

4.A.2.1. Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 7,000 megawatts ("MW") of projects online or under development,[24] ranging from the following: (a) utility-owned solar and small hydro generation; (b) long-term RPS contracts for large wind, geothermal, solar, and biomass generation; and (c) small Feed-In Tariff ("FIT") contracts for solar photovoltaic ("PV"), biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 7 and 8.

As described in further detail in Section 7.2, to model the project failure variability inherent in project development, PG&E assumes that project viability for a to-be-built project is a function of the number of years until its contract start date. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations.

Consistent with the project trends reported in its 2018 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have helped the development of the market for renewables. PG&E expects renewables to continue to be cost-competitive in the future, whether or not the ITC and PTC are extended. Progress in the siting and permitting of projects also has supported PG&E's sustained high success rate. As described in more detail in this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

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24 Less than 100 MW of PG&E's existing portfolio is under development.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in the remainder of Section 4.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 7, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted.

4.A.3. RPS Market Trends and Lessons Learned

As its renewable resource portfolio has expanded to meet RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the following four key goals: (1) reaching, and sustaining, the existing RPS targets; (2) minimizing customer cost within an acceptable level of risk; (3) ensuring PG&E maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty; and (4) aligning PG&E's RPS portfolio to its customers' needs.[25] PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape. This strategy could significantly change depending on the outcome in the PCIA OIR.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

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25 In the future, PG&E's renewable resource strategy will also consider the directives of the Commission's integrated resources planning process.

Another trend, driven by the growth of renewable resources in the California Independent System Operator ("CAISO") system, is the downward movement of mid-day wholesale energy market prices. Many renewable energy project types have minimal operating costs, and therefore additions of these renewables tend to move wholesale energy market clearing prices down. This has led to a change in the energy values associated with RPS offers, with decreasing value for renewable projects that generate during mid-day hours.

The growth of renewable resources also has produced challenges, such as negative wholesale energy market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address negative pricing situations that are likely to increase in the future. These provisions have customer benefits. Economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 12.

4.A.4. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Key RPS compliance requirements were established in D.11-12-020, D.12-06-038, and D.16-12-040. These requirements will need to be modified by the Commission to incorporate the revised statutory RPS targets in the recently enacted SB 100.

One RPS compliance criterion of particular importance is that involving the need to ensure a balanced RPS portfolio. Implementing Pub. Util. Code Section 399.16, the Commission issued D.11-12-052 to define three statutory portfolio content categories ("PCC") of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. The ultimate effect of these portfolio balancing requirements is to significantly increase the demand of LSEs, including PG&E, for resources that are directly interconnected or deliver in real time to a California Balancing Authority like CAISO.

Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 7; in particular, uncertainty regarding bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

4.A.4.1. Near-Term Need for RPS Resources

Because PG&E currently has no incremental procurement need until after 2033 under existing RPS requirements, PG&E is proposing to not hold an RPS solicitation during this RPS Plan cycle. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for any future Request for Offers ("RFO") in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2020 through mandated procurement programs, such as the BioMAT and BioRAM Programs. PG&E will seek permission from the Commission should PG&E intend to procure any incremental RPS volumes other than amounts separately mandated by the Commission during the time period covered by the 2019 RPS Plan.

4.A.4.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. Currently, PG&E is projecting a decrease in retail sales in 2020 and a continued, but modest decline through 2026 before growing slowly thereafter. These changes are driven by the increasing impacts of energy efficiency ("EE"), customer-sited generation, and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 7.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 7, 8, and 9, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement ("MMoP"); and (2) the need to account for PG&E's risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 7 and 8. Beyond these considerations, PG&E notes that future regulatory or legislative changes that are not currently included in PG&E's models could significantly impact PG&E's RPS need.

4.A.5. RPS Position Management and Sales of RPS Products

As described in Section 8.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next 10 years, in part due to dramatic recent and ongoing changes to PG&E's retail sales forecast. Accordingly, PG&E continues to seek authority in this 2019 RPS Plan to sell RPS volumes from its portfolio through short-term sales under the updated RPS Sales Framework in Appendix F and in Section 10 as described below.

4.B. Alignment with Load Curves

4.B.1. Anticipated Renewable Energy Technologies and Alignment of PG&E's Portfolio With Expected Load Curves and Durations

As described in previous RPS Plan filings, PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. Specifically, 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. Starting with its 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio.

4.B.2. Optimizing Cost, Value, and Risk for the Ratepayer

To mitigate RPS cost impacts, PG&E's fundamental strategy is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet compliance requirements; (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines, and (3) selling renewables in accordance with its framework described in Appendix F. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline and using the Bank to mitigate risks associated with load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13, the cost impacts of mandated procurement programs that focus on particular technologies or project sizes may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process where all technologies can compete to offer the best value to customers at the lowest cost. Finally, as described in Section 10, as part of its overall RPS position and management strategy, PG&E is proposing updates to its previously-approved framework for the sale of RPS volumes that returns revenue from sales to its customers.

4.B.3. Long-Term RPS Optimization Strategy

To optimize cost, value, and risks for customers, PG&E's long-term RPS optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to achieve the RPS compliance requirements. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's stochastically-optimized net short ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 7 and 8.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E is proposing to not hold a 2019 RPS procurement solicitation, future incremental procurement aimed at avoiding the need to procure extremely large volumes in any single year remains a component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes sales of surplus procurement that provide a value to customers. PG&E has developed a framework for sales, which was approved in previous iterations by the CPUC, and is provided in Appendix F.

The third component of the optimization strategy is effective use of the Bank. Under the existing RPS targets and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in 2029. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted]. Section 8 below provides additional information regarding the use and size of PG&E's Bank.[26] PG&E notes that the size of its Bank may be impacted by the outcome of the PCIA OIR, and that any such change is not currently assumed in PG&E's RNS modeling.

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26 *Ibid.*

4.C. Responsiveness to Policies, Regulations, and Statutes

4.C.1. Adoption and Implementation of SB 350

On October 7, 2015, Governor Brown signed SB 350,[27] known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increased the RPS target from 33 percent in 2020 to 50 percent in 2030.

On June 29, 2017, the Commission adopted D.17-06-026, which implements new compliance requirements for the RPS program in response to changes made by SB 350. The Decision addresses the implementation of new rules for the use of long-term contracts in RPS compliance for all compliance periods beginning January 1, 2021. The new long-term requirement provides that, beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the RPS requirement of each compliance period must be from long term contracts. The Decision also: (1) implements new rules for applying excess procurement in one compliance period to later compliance periods beginning January 1, 2021; (2) provides direction for early compliance with the new long-term contract and excess procurement rules in the 2017-2020 compliance period; and (3) integrates changes made by SB 350 into the ongoing RPS compliance process.

In order to elect the early compliance option provided in SB 350, a retail seller must give notice of its election not later than 60 days from the effective date of D.17-06-026. PG&E gave notice on August 17, 2017, by letter addressed to the Director of Energy Division and served on the service list for R.15-02-020 of its election to comply early with the new long term and excess procurement requirements. Also in compliance with D.17-06-026, PG&E filed a motion on September 22, 2017 to update its RPS Procurement Plan to, among other things, reflect its election to comply early with the new long term and excess procurement requirements. Accordingly, the analysis set forth in the 2019 RPS Plan reflects PG&E's expectation that it will be subject to these

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[27] SB 350, Stats. 2015, Ch. 547 (De León).

new long term and excess banking rules beginning in the current 2017-2020 RPS compliance period.

On June 6, 2018, the Commission issued D.18-05-026, in which it implemented certain enforcement and penalty provisions contained in the SB 350 amendments to the RPS statute. Of particular relevance to this 2019 RPS Plan is the requirement in D.18-05-026 that each retail seller must annually demonstrate that transportation electrification is quantitatively accounted for in their RPS procurement plans. PG&E has described how it incorporated transportation electrification into its forecast of retail sales in Section 6.1.2.

4.C.2 Impact of GTSR Program

In 2013, SB 43[28] enacted the GTSR Program allowing PG&E customers to meet up to 100 percent of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment. In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." The most recent GTSR Annual Report for the program was filed with the Commission on March 15, 2019.

The GTSR Program impacts PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected as described below; and (2) retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply GTSR customers from an interim pool of existing RPS resources until new dedicated GTSR projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in a decrease in PG&E's RPS supply. However, there is also a possibility that PG&E's RPS supply could increase in the future if generation from GTSR-dedicated projects exceeds the demand of GTSR customers. In this case, those volumes procured for GTSR would then be added to

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28 SB 43, Stats. 2013, Ch. 413 (Wolk).

PG&E's RPS portfolio, even if PG&E had no RPS need. PG&E has developed tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and GTSR Programs.

In conformance with D.15-01-051[29] and as described in the Joint Procurement Implementation Advice Letter, PG&E reports annually on the amount of generation transferred between the RPS and GTSR Programs in a report that is filed by September 1 each calendar year. In 2018, the sales under the Solar Choice Program was covered by the PG&E's Solar Choice Program-dedicated resources procured specifically for the Program. As more generation was procured under the program than was needed for Solar Choice customers in 2018, the excess solar generation will be transferred from the PG&E's Solar Choice Program to the RPS Program. PG&E anticipates a similar situation for 2019: the generation of the Solar Choice dedicated resources is likely to exceed the need of Solar Choice customers, and the excess solar generation will be transferred from the Solar Choice Program to the RPS Program.

On June 21, 2018, the Commission issued D.18-06-027 requiring the IOUs to implement two new Green Tariff programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs"). As approved in Res.E-4999 and in order to expedite program implementation for the new Disadvantaged Communities Green Tariff ("DAC-GT") program, PG&E will use the generation that exceeds customers' need from dedicated resources in the Solar Choice Program beginning in the first quarter of 2020. Of these dedicated Solar Choice resources, PG&E will utilize up to approximately 30 MW from facilities that are in the top 25% DACs. If necessary, and only after all 30 MW of the dedicated Solar Choice resources are exhausted, PG&E would use other qualifying RPS-eligible resources in its portfolio for the DAC-GT program. Generation utilized for the DAC-GT Program from any such resources would no longer be counted toward PG&E's RPS targets, which

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29 *See* D.15-01-051, p. 50.

could result in a decrease in the generation available to meet PG&E's bundled customer RPS requirements.[30] The resources will be utilized on an interim basis until dedicated new DAC-GT projects come online. Once new DAC-GT projects come online, generation may continue to be transferred from the Solar Choice Program to the RPS Program based on the need of Solar Choice customers. Use of Solar Choice or other RPS-eligible resources on an interim basis will be the only impact to PG&E's RNS position from the DAC-GT program as all costs will be recovered through GHG allowance proceeds, and if insufficient revenue is available, then through Public Purpose Program funds.

4.C.3 Implementation of Mandated Procurement Programs

Existing mandated procurement programs for RPS-eligible resources include BioMAT, ReMAT, and PV RAM. As described below, PG&E continues to seek to procure resources under BioMAT despite a demonstrated lack of need for additional RPS resources. ReMAT has been suspended and PG&E completed its PV RAM program in 2018.

4.C.3.1 BioMAT

On September 27, 2012, SB 1122[31] was passed, requiring California's IOUs to procure a total of 250 MW of new small-scale bioenergy projects that are 3 MW or less in size through the FIT Program. Other LSEs (including publicly-owned utilities ("POUs"), Electric Service Providers ("ESPs"), and CCAs) do not have this procurement obligation. Because all customers benefit equally from mandated procurement through BioMAT, PG&E believes that all customers should contribute equitably to their costs.

The total IOU BioMAT mandate is allocated into three technology categories with separate MW targets: (1) 110 MW of biogas from wastewater plants and green waste; (2) 90 MW of dairy and other agriculture bioenergy; and (3) 50 MW of forest

[30] PG&E will update its RNS following the dedication of any RPS resources currently included in the forecast of generation in the RNS to the DAC-GT program.

[31] SB 1122, Stats. 2012, Ch. 612 (Rubio).

waste biomass. PG&E's SB 1122 BioMAT Program began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. PG&E has held bimonthly BioMAT auctions since February 2016.

On October 30, 2018, the Commission issued the BioMAT Program Review and Staff Proposal[32] to assess BioMAT program performance to date and recommend programmatic and procedural changes to simplify the procurement process, expand program participation, reduce ratepayer expenditures, and help achieve statewide goals. The proposal describes the Energy Division's key observations about program performance, sets a timeline for a program review, lays out a proposal for program changes, and seeks comment on the proposal to inform program workshops. The review will result in recommendations via a staff proposal for program changes to be considered as a part of a future RPS proceeding. The Joint IOUs filed comments in response to the Staff Proposal on December 7, 2018 and reply comments on January 4, 2019. Resulting workshops to discuss the program review have yet to be scheduled.

On a parallel track, the Commission issued D.18-11-004 instructing the IOUs to make changes to the Power Purchase Agreement ("PPA") and tariff to reflect the ability for bioenergy facilities that are interconnected to existing transmission lines (per Assembly Bill ("AB") 1923[33]) to be able to participate in the program. PG&E filed Advice Letter ("AL") 5454-E with these changes, which the Commission approved on January 18, 2019.

4.C.3.2 ReMAT

ReMAT was established in May 2012 when the Commission made several revisions to its FIT program. These changes included increasing the eligible project size from 1.5 MW to 3 MW, establishing a 750 MW program cap, and adopting the ReMAT pricing mechanism.[34] IOUs and POUs were allocated a share of the 750 MW

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32 See BioMAT Program Review and Staff Proposal, issued on October 30, 2018.

33 AB 1923, Stats. 2016, Ch. 663 (Wood).

34 *See* D.12-05-035.

program cap; other LSEs (ESPs and CCAs) do not have this procurement obligation. Because all customers benefit equally from the mandated procurement through ReMAT, PG&E believes that all customers should contribute equitably to their costs.

PG&E held bi-monthly auctions for ReMAT resources beginning on November 1, 2013. On December 6, 2017, the *Winding Creek Solar LLC v. Peevey* court decision[35] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of avoided cost and (2) the program MW cap violates PURPA's must-take obligation. On December 5, 2017, the Executive Director of the CPUC issued a letter ordering the three IOUs to refrain from signing new ReMAT contracts, to suspend holding any ReMAT program periods, and to stop accepting new applications for the program. As a result, all ReMAT program activity is currently on hold.

4.C.3.3 PV Program Procurement Through RAM (PV RAM)

In D.14-11-042, the Commission granted PG&E's petition to transfer approximately 200 MW from PG&E's PV Program to the Renewable Auction Mechanism 6 solicitation and two additional solicitations. On August 18, 2018, PG&E received approval in AL 5330-E for a PPA that met the final remaining procurement obligation pursuant to the original PV Program, thereby concluding the program.

4.C.4 Energy Storage

AB 2514,[36] signed into law in September 2010, requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514.

On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the

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35 Available at https://www.leagle.com/decision/infdco20171207935.

36 AB 2514, Stats. 2010, Ch. 469 (Skinner).

decision, PG&E completed its 2014 and 2016 Energy Storage RFOs. On December 1, 2017, PG&E submitted six executed agreements that resulted from the 2016 Energy Storage RFO for CPUC approval.[37]

In January 2018, the CPUC issued Res.E-4909, authorizing PG&E to launch an accelerated solicitation for energy storage projects to contribute to reliability needs for three specified local subareas in the northern central valley and in an area spanning Silicon Valley to the central coast (Pease, Bogue, and South Bay – Moss Landing local sub-areas). PG&E issued its Local Sub-Area Solicitation in February 2018 and received offers from numerous participants. PG&E ultimately selected and submitted for approval four projects to come online in 2020 to be located within the South Bay – Moss Landing local sub-area: one offer for a 182.5 MW utility-owned project and three offers for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage.[38] The Commission approved these projects in Res.E-4949, including allowing them to count toward PG&E's AB 2514 targets. These projects are also expected to help increase the overall flexibility of the grid to integrate high levels of wind and solar generation.

PG&E did not hold a 2018 Energy Storage RFO because PG&E's past storage procurement was within the 2018 AB 2514 target established by the Commission. Further detail on PG&E's energy storage procurement can be found in its most recent biennial Energy Storage Plan.[39]

AB 2868,[40] signed into law in September 2016, required that the IOUs file applications for programs and investments to accelerate widespread deployment of

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37 Application of Pacific Gas and Electric Company (U 39-E) for Approval of Agreements Resulting from Its 2016-2017 Energy Storage Solicitation and Related Cost Recovery, Application ("A.")17-12-003.

38 Advice 5322-E, Energy Storage Contracts Resulting from PG&E's Local sub-area RFO Per Res.E-4909, submitted June 29, 2018.

39 Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018, A.18-03-001.

40 AB 2868, Stats. 2016, Ch. 681 (Gatto).

distributed energy storage systems. In March 2018, PG&E filed its proposal with the Commission to deploy 166.66 MW of distributed energy storage in compliance with AB 2868.[41] On February 26, 2019, the Commission issued a Proposed Decision approving PG&E's proposal for a behind the meter thermal energy storage program that would deploy up to 5 MW of controllable water heaters at customers sites by 2024, prioritizing low-income customers. The goals of the program are to shift water heating load from peak to off-peak hours and provide benefits to customers through lower energy bills and a pay for performance incentive. A final decision on PG&E's AB 2868 proposal was pending at the Commission as of June 21, 2019.

In the following discussion, PG&E addresses how its acquisition and use of energy storage systems is designed to achieve the purposes set forth in Pub. Util. Code Section 2837:

(a) Integrate intermittent generation from eligible renewable energy resources into the reliable operation of the transmission and distribution grid.

PG&E's energy storage portfolio provides renewable energy resource integration benefits by virtue of the storage systems' participation in the wholesale energy and capacity markets. The energy storage procured by PG&E in the 2018 Energy Storage Solicitation and in the Local Sub-Area Solicitation includes contracts for Resource Adequacy ("RA"), which requires the energy storage resources to be bid into the wholesale energy market. Accordingly, the CAISO will be able to dispatch these resources when needed and economically desirable in the Day-Ahead and Real-time Markets to balance demand and a diverse supply portfolio for the reliable operation of the grid.

(b) Allow intermittent generation from eligible renewable energy resources to operate at or near full capacity.

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41 Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018, A.18-03-001.

For the same reasons described in (a), above, PG&E's energy storage portfolio can reduce the need for renewable energy curtailments by virtue of the storage resources' participation in the CAISO market.

(c) Reduce the need for new fossil-fuel powered peaking generation facilities by using stored electricity to meet peak demand.

PG&E's energy storage portfolio can reduce the need for new fossil-fuel peaking generation by virtue of the storage resources' participation in the CAISO market and inclusion in the Commission's IRP process. The energy storage procured by PG&E includes contracts for RA, which requires the energy storage resources to be bid into the CAISO market in compliance with their Must Offer Obligations. PG&E's energy storage resources are therefore included in the Commission's and CAISO's forecasts of resources available to meet peak system load and reduce the need for new marginal resources to be built.

(d) Reduce purchases of electricity generation sources with higher emissions of GHGs.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can reduce the need for generation sources with higher GHG emissions by virtue of the storage resources' participation in the CAISO market.

In the case of PG&E's Local Sub-Area procurement, these energy storage systems are expected to directly reduce GHG emissions. This procurement was directed by the Commission specifically to obviate the need for three natural gas plants to remain online for local reliability in the Moss Landing local sub-area.[42]

(e) Eliminate or reduce transmission and distribution losses, including increased losses during periods of congestion on the grid.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can reduce losses on the grid by virtue of the storage resources' participation in the CAISO market.

(f) Reduce the demand for electricity during peak periods and achieve permanent load-shifting by using thermal storage to meet air-conditioning needs.

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42 *See* Res.E-4909.

PG&E's energy storage portfolio does not currently include thermal storage to meet air-conditioning needs.

(g) Avoid or delay investments in transmission and distribution system upgrades.

PG&E's energy storage portfolio includes the Llagas Energy Storage project, which is a 20 MW distribution deferral project slated to come online in 2021. The deployment of the Llagas lithium ion battery storage system was designed to defer the need for upgrades at PG&E's Llagas substation.

(h) Use energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities.

For the same reasons discussed in (a), above, PG&E's energy storage portfolio can provide ancillary services by virtue of the storage resources' participation in the CAISO market.

4.D. Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including 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 the Net Market Value ("NMV") valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity may have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in the procurement of different technology types. Such considerations have resulted in a diverse set of resources that make up PG&E's portfolio over the ten-year planning horizon.[43]

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. PG&E believes, as a general principle, that less restrictive procurement structures, in contrast to mandated programs, will provide the best opportunity to maximize value for its customers. Less restrictive procurement structures also will enable proper responses to changing market conditions and more competition between resources. PG&E further believes that geographic or technology-specific mandates add additional costs to RPS procurement.

4.E. Lessons Learned

Please see Section 10.A.5, below, where lessons learned from PG&E's portfolio optimization activities over the past year are discussed in the context of its recent and ongoing RPS sales solicitations.

4.F. Conformance with IRP

Overall, this PG&E 2019 RPS Plan conforms to and is consistent with the renewable procurement findings from PG&E's 2018 IRP filed in R.16-02-007 on August 1, 2018.[44] As stated in PG&E's 2018 IRP filing, under both Commission's Conforming and PG&E's Preferred planning scenarios, PG&E's IRP found no incremental renewable procurement need beyond PG&E's planned procurements to

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43 See PG&E's 2018 IRP filed on August 1, 2018 in CPUC R.16-02-007 Table 11 (p. 49) for a quantitative breakdown of its portfolio by technology type.

44 See PG&E's 2018 IRP filed on August 1, 2018 in CPUC R.16-02-007; Small differences between the plans are largely driven by the latest updates on the forecasted demand, which does not trigger any incremental procurement need.

meet its obligations and support various existing state mandates and programs through the planning year 2030. Given its lack of procurement need, both PG&E's 2018 IRP and its 2019 RPS Plan conform to the Commission's recently adopted the Preferred System Portfolio in D.19-04-040.[45]

5. Project Development Status Update

PG&E, Southern California Edison Company, and San Diego Gas & Electric Company file monthly RPS Database submissions with the CPUC. These monthly submissions contain a larger collection of data on each RPS project than previously provided in the IOUs' Project Development Status Reports. Project development status updates for RPS contracts can now be obtained from the publicly available data published on the Commission's website at http://cpuc.ca.gov/RPS_Reports_Data.

6. Potential Compliance Delays

This Section addresses factors, including those identified in the RPS statute, that may impact PG&E's ability to comply with its near-term RPS requirements or its need for a statutory waiver of those requirements.[46] While in general PG&E does not currently foresee obstacles to achieving compliance with existing RPS requirements, market conditions and changes in law and regulatory requirements could change this outlook in the future.

6.1 Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite PG&E's current expectation that it will be able to comply on time with existing RPS requirements, significant market, operational, or regulatory changes could

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45 That is, PG&E's planned RPS portfolio captures its portion of the existing and planned resources modeled in the Preferred System Portfolio.

46 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Pub. Util. Code § 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

impact that assessment. This section describes briefly some of the risks and the steps PG&E is taking to mitigate these risks.

6.1.1 Curtailment of RPS Generating Resources

As discussed in more detail in Section 12, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may reduce the RPS energy available for compliance. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 7.2.

6.1.2 Transportation Electrification

PG&E's retail sales forecast is adjusted for expected load increases due to electric vehicle ("EV") adoption. PG&E's EV energy demand and capacity forecast in the 2019 RPS Plan cycle includes medium-duty and heavy-duty vehicle segments, in addition to the light-duty segment. In order to consider the impact of EVs on PG&E's annual load, PG&E developed an internal probabilistic assessment of EV penetration, leveraging: (1) aggregated EV registration data available through December 2018; (2) policy goals declared through December 2018 as well as modeling of compliance for existing policy; (3) EV adoption scenarios developed by ICF International, Inc. in the California Electric Transportation Coalition's Transportation Electrification Assessment; and (4) inputs describing typical EV electricity consumption and charging behavior. PG&E did not directly leverage the California Energy Commission's ("CEC") 2017 Integrated Energy Policy Report ("IEPR") transportation electricity demand forecast in developing its EV forecast. PG&E and the CEC use two fundamentally different modelling approaches, with PG&E using a policy-driven adoption model (top down) and the CEC using a consumer choice model (bottom-up). Thus, modeling assumptions are not easily transferable between the two approaches. However, PG&E did compare its EV forecast results against the CEC's reference scenario and found PG&E's forecast to be about 35% higher than the CEC forecast for PG&E’s service territory in 2030. The results derive from PG&E’s higher adoption forecast which considers approximately 2 million light-duty EVs by 2030, whereas the CEC’s forecast considers approximately 1.5 million light-duty EVs in PG&E’s territory. In addition to using different modeling approaches, the CEC did not update its medium-duty and heavy-duty vehicle forecast in its 2018 IEPR Update (November 2018). PG&E and the CEC use different input assumptions that may impact the forecast results. For example, PG&E’s EV forecast assumes growth in the rideshare market and 100% electrification of transit buses by 2040, whereas the CEC IEPR forecast does not.

6.1.3 Risk-Adjusted Analysis

As more fully described in the following section, PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. PG&E’s experience with RPS procurement is that developers often experience difficulties managing some of the development issues described above. As described in Section 9, PG&E’s expected RPS need calculation incorporates a MMoP to account for some anticipated project failure and delays in PG&E’s existing portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 60 percent RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

7. Risk Assessment

Dynamic risks, such as the factors discussed in Section 6 that could lead to potential compliance delays, directly affect PG&E’s ability to plan for and meet compliance with the RPS requirements. As described elsewhere in this RPS Plan, PG&E is currently well-positioned to meet its RPS compliance requirements and its risk of non-compliance is low. Nevertheless, to account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; 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 MMoP, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[47] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[48]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 7.1 identifies the three risks accounted for in PG&E's deterministic model. Section 7.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 7.3 describes how the risks described in the first two sections are incorporated into both models, including details

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47 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

48 PG&E has also developed a framework to assess whether to hold or sell RPS volumes, included in Appendix F.

about how each model operates and the additional boundaries each sets on the risks. Section 7.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 8 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices A.1 and A.2. Section 9 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

7.1 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.

2) Project Failure: the determination of whether or not 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 7-1
DETERMINISTIC MODEL RISKS

Risk	Methodology	Applies to
Standard Generation Variability	• For non-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 Irrigation District and Water Agency ("ID&WA") 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

7.1.1 Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non-QF; non-hydro QFs; and hydro QF projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, normalized for average water year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. The UOG and ID&WA forecast are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix C.

7.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E

categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0 percent deliveries) and ON (represented with 100 percent deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online or none of the generation comes online.

1) **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":
   - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.);
   - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data);
   - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization;
   - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability;
   - Whether a PPA amendment has been executed but has not yet received regulatory approval; and
   - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[49] PG&E does not currently have any in-development projects categorized as "OFF" in its deterministic model.

2) **ON** – Projects in all other categories are assumed to deliver 100 percent of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes within a reasonable timeline.

7.1.3 Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

7.2 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.

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49 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

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 Uncertainty: 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 Participating Transmission Owner ("PTO")-ordered curtailment; and
4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

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 7-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 7-2
CATEGORIZATION OF IMPACTS ON RPS POSITION

	Impact	Categorization
Higher Impact on RPS Position	**1. Retail Sales Uncertainty:** Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
	2. Curtailment: Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
	3. 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	**4. Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

7.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, EVs, and distributed generation.

For DA, additional load loss based on DA expansion required by SB 237 has been incorporated into PG&E's stochastic model. Specifically, PG&E assumes that the 4,000 GWh DA expansion ordered occurs in January 2020.[50] PG&E relied on its Fall 2018 DA waitlist to estimate the proportion of customers departing from bundled service versus CCA service. PG&E assumes its service territory will be allocated 38 percent of the 4,000 GWh. PG&E forecasts a total of 11,175 GWh of DA load in its service territory in 2020, including both new DA load under SB 237 and existing DA load under SB 695. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting additional increases in DA beyond those provided for in SB 237.

Load loss due to CCA departure is modeled in two categories: (1) existing CCAs that have already departed or will depart and serve load by 2020; and (2) potential CCAs that have expressed interest in forming based on publicly available information. For existing CCAs, PG&E follows a meet and confer process to communicate with CCAs regarding their load forecasts. PG&E receives year-ahead load, peak demand, and customer forecasts from the CCAs, and forecasts future years' volumes using PG&E's forecasted total system load growth rate, which accounts for economic/demographic factors, weather, and growth of DER technologies such as solar PV, EE. For potential CCAs, PG&E has developed a stochastic (probabilistic) approach

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50 Modeling and modeling assumptions were completed prior to D.19-05-043, which delayed DA expansion to January 2021.

to forecast CCA load departure. This model uses publicly available information—including feasibility studies, implementation plans, board meetings, and news articles—to assign probabilities to all communities considering CCA formation. Similar probabilities are applied to communities with the same CCA maturity levels. The model uses 2018 annual energy load as the benchmark, and PG&E applies system load growth percentages to approximate future load growth or decline.

7.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from 1985-2012, wind generation data from 1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is uncorrelated among technologies.

7.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered, or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). Curtailment forecasts ramp from a historical level of [redacted]

[redacted].[51] These modeling assumptions will not necessarily reflect the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 12 for more information regarding curtailment.

7.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] percent chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower.

7.2.5 Comparison of Model Assumptions

Table 7-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure,

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51 [redacted]

RPS generation, and curtailment. Section 8 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 7-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[(a)]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2017-2018 IRP for later years (Appendix A.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix A.2).	Distribution based on most recent (2019) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "OFF" projects with high likelihood of failure per criteria. "ON" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
3) RPS Generation Variability	Non-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, UOG and ID&WA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2017 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

(a) These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

7.3 How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

7.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives; (b) inputs; and (c) constraints of the model:
   (a) The objective is to minimize procurement cost.
   (b) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes)[52] in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] annually.
   (c) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted], less than [redacted], less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

[52] Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not allow for price arbitrage through sales of RPS generation in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2020 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this 2019 RPS Plan.

7.5 Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the existing RPS targets are shown in Row La of PG&E's Alternate RNS in Appendix A.2.

The results of both the deterministic and stochastic models are discussed further in Section 8 and MMoP is addressed in Section 9.

8. Quantitative Information

As discussed in Section 7, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix A. Appendix A.1 presents the RNS in the form required by the ALJ's Ruling on RNS issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendix A.2 is a modified version of Appendix A.1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its Bank size and PG&E's analysis of the minimum bank needed.

8.1 Deterministic Model Results

Results from the deterministic model under a 60 percent by 2030 RPS target and 60 percent RPS annually thereafter are shown as the physical net short in Row Ga of Appendices A.1 and A.2. Appendix A.1 provides a physical net short calculation using PG&E's April 2019 internal Bundled Retail Sales Forecast for years 2019-2023 and the IRP sales forecast for 2024-2036,[53] while Appendix A.2 relies exclusively on PG&E's April 2019 internal Bundled Retail Sales Forecast. Following the methodology described in Section 7.1, PG&E currently estimates a long-term volumetric success rate of 100 percent for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fb of Appendix A.2. 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 6, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix A.2 depict PG&E's expected

[53] Bundled sales forecast used for 2024-2036 is from PG&E's approved 2018 LSE IRP filed for the 2017-2018 IRP Cycle.

compliance position using the current expected need scenario before application of the Bank.

8.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter. Because PG&E uses its stochastic model and internal Bundled Retail Sales Forecast to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix A.2 for the 60 percent RPS target. Appendix A.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendix A.2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

Under the existing RPS targets, PG&E is well-positioned to meet its compliance period requirements through the fifth compliance period (2025-2027). As shown in Row Lb of Appendix A.2, the stochastic model shows a third compliance period RPS position of [redacted], a fourth compliance period RPS position of [redacted], a fifth compliance period RPS position of [redacted], and a sixth compliance period RPS position of [redacted]. Appendix A.2 also shows a physical net short of approximately [redacted] beginning in 2029 (Row Ib plus Row Gd).

For both tables, Row Lb includes both PG&E's executed and generic RPS sales volumes shown in Rows Fd and Ib, respectively.[54] The annual RPS sales volume forecast assumption is based on RPS sales executed in 2018 as well as the proposed

54 Total forecasted RPS sales in 2019 and 2020 are based on executed sale agreements through May 31, 2019.

sales framework requested in this 2019 RPS Plan and is included in PG&E's forecast for RPS position planning purposes. Based on the sales framework approved in the 2018 RPS Plan, the forecasted RPS sales volumes could potentially increase an additional [redacted] to what is currently forecasted, which would result in the first year of incremental procurement need being [redacted]. In the event that the total RPS generation less RPS sales falls below the RPS Compliance requirement in any given year, PG&E would still meet its RPS Compliance requirement through the use of previously accumulated RPS Bank (see Row J in Appendix A.2).

8.2.1 SONS to Meet Non-Compliance Risk Target

To evaluate possible procurement strategies, PG&E selected the following non-compliance risk targets for each future compliance period: [redacted]

Figure 8-1 shows the model's forecasted procurement need and resulting Bank usage under the 60 percent RPS by 2030 target and 60 percent RPS annually thereafter. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in 2029, the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 7. Appendix A.2 provides the detailed results. Annual forecasted Bank usage is shown as the sum of Rows Gd and Ib of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as after 2033. Should PG&E engage in additional RPS sales, this may result in an earlier procurement need year and its position will be updated in subsequent RPS Plans.

FIGURE 8-1
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED BANK USAGE AND SONS

[redacted]

Note: Bank usage values have been rounded to the nearest 100 GWh.

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

8.2.2 Bank Size Forecasts and Results

Figure 8-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2033. PG&E's total Bank size as of the end of the second compliance period was approximately 12,800 GWh. The stochastic model's results currently project PG&E's Bank size to increase in the second through fifth compliance periods and [redacted]

[redacted] (as shown in Figure 8-2, as well as in Appendix A.2, Row J). As described in Section 8.2 above, the forecasted 2033 Bank total assumes a total of 50,500 GWh of RPS sales from 2019-2028.

FIGURE 8-2
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED CUMULATIVE BANK

[redacted]

Note 1: Bank values in CP1 and CP2 are based on the total 'Excess Procurement Bank' in PG&E's RPS Compliance Report.
Note 2: Bank values in CP3 and beyond have been rounded to the nearest 100 GWh.

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

8.2.3 Minimum Bank Size

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[55] The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 8-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]

Based on current model assumptions and inputs, Figure 8-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted] Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level.

FIGURE 8-3
CONFIDENTIAL
DISTRIBUTION OF DELIVERY MINUS TARGET FROM 2026 THROUGH 2030 UNDER A 60 PERCENT RPS TARGET

[redacted]

As stated in Section 8.2.2, the stochastic model's results show PG&E's forecasted [redacted]. PG&E's strategy is to maintain an

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55 [redacted]

adequate Bank in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs.

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 8-3 illustrates.

8.3 Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this 2019 RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales. PG&E will update its RNS in the future as it executes any such sale agreements.

9. Minimum Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory MMoP to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 60 percent RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these procurement margin measures and how each is incorporated into PG&E's quantitative analysis of its RPS need.

9.A. MMoP Methodology and Inputs

Please generally see Section 7, above, for a discussion of PG&E's modeling methodology and inputs.

9.B. MMoP Scenarios

9.B.1. Statutory MMoP

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[56] PG&E's reasonableness in incorporating this statutory MMoP into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[57]

As described in more detail in Section 7, 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). PG&E considers this deterministic result to be its current statutory margin of procurement.[58] However, as discussed in Sections 7 and 8, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and

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56 Pub. Util. Code § 399.13(a)(4)(D).

57 *Id.*, § 399.15(b)(5)(B)(iii).

58 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums.

uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

9.B.2. VMOP

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory MMoP.[59] As discussed further in Sections 7 and 8, 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.

While PG&E's current optimization strategy projects the use of a portion of PG&E's projected Bank to meet compliance requirements in 2029 and beyond, PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. Using the Bank as its VMOP will reduce non-compliance risk while also helping to avoid long-term over-compliance above the existing RPS targets and thus reducing long-term costs of the RPS Program, which could result if PG&E held both a Bank and an additional VMOP. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 7 and 8.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

10. Bid Solicitation Protocol, Including Least-Cost Best-Fit Methodologies

As previously described, PG&E is well positioned to meet its RPS targets until after 2033. As a result, PG&E proposes to not hold a 2019 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2019 and 2020

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59 Pub. Util. Code § 399.13(a)(4)(D).

through any other Commission-mandated programs, such as the BioMAT program. PG&E will seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2019 RPS Plan, except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2019 RPS Plan a solicitation protocol for procuring additional RPS resources. PG&E's proposal to conduct one or more RPS sales solicitations during this RPS Plan cycle are described more fully below.

10.A. Solicitation Protocols for Renewable Sales

10.A.1. Updates to the RPS Sales Framework

The goal of PG&E's RPS Sales Framework is to prudently manage its portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. PG&E will continue to seek and evaluate opportunities to execute short-term contracts to sell RPS-eligible products from its portfolio under the RPS Sales Framework. These short-term sales would be for volumes to be delivered in the years 2020-2021 in order to preserve optionality while resolving Phase 2 of the PCIA OIR.

The objective of PG&E's updated Sales Framework is to return to a balanced RPS position in a timely manner, and mitigate price risk to customers, by adhering to the following principles:

- Compliance: Ensure PG&E can maintain compliance with RPS requirements;
- Value for Customers: Ensure value for customers; and
- Flexibility: Adapt to a fluctuating market and policy landscape through annual revisions in the RPS Plan filing.

In comparison to the approved 2018 RPS Sales Framework, PG&E ~~is proposing several the following~~ refines its framework to ~~ments to simplify its framework, align with the uncertainty in the current PCIA proceeding, and allow PG&E flexibility to manage its position with short-term sales. Below are the main refinements PG&E is proposing:~~

- [redacted]

[redacted]

10.A.2. Implications of the Updated Sales Framework

A key aspect of the updated RPS Sales Framework is that it may result in volumes of sales [redacted] [60] [redacted]

10.A.3. Implementation of the RPS Sales Framework

Based on current inputs to the RPS Sales Framework described in Appendix F, PG&E will target issuing three, with a minimum of two, solicitations for the sale of bankable, bundled renewable generation and RECs in 2020.[61] PG&E anticipates selling short-term products, meaning contracts of two years or less in duration, under the Framework.

PG&E intends to execute sales through PG&E-initiated solicitations. Confidential Appendix E contains PG&E's sales solicitation protocol and pro forma sales agreement. The sales solicitation protocol and pro forma sales agreement are largely unchanged from the 2019 Bundled RPS Energy Sale Short Form Confirm approved in the 2018 RPS Plan cycle. PG&E anticipates minimal negotiations with buyers with respect to the form agreement.

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60 PG&E cannot guarantee that its RPS position will be above the target given the uncertainty in retail sales and forecasted generation. If PG&E did sell its excess and then its actual position was shorter than its compliance target, PG&E has sufficient banked volumes to ensure it can comply with the RPS targets.

61 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations will depend on the outcome of prior solicitations and/or changes to PG&E's RPS position.

PG&E will file short-term sales agreements resulting from a solicitation that are negotiated based upon the pro forma sales agreement, with any necessary modifications, as Tier 1 Advice Letters for Commission approval.[62]

10.A.4. 2018 RPS Sales – Lessons Learned

While PG&E has executed a limited number of agreements for the sale of RPS volumes from PG&E's portfolio, PG&E's second such solicitation (the "2018 RPS Sales Solicitation") was issued in 2018. Upon completion of the 2018 RPS Sales Solicitation, PG&E surveyed market participants to solicit feedback on how to improve the process and to understand why certain market participants did not bid. In addition, PG&E received feedback from the Independent Evaluator assigned to monitor the solicitation and resulting negotiations.

As a result, PG&E has identified a number of best practices to incorporate in future solicitations.

10.A.4.1 Desire for PCC Certainty

Counterparties consistently sought contract language certifying that the bundled RPS volumes to be sold and purchased would be deemed to be PCC 1 by the Commission. PG&E agreed to represent that the resources used for the sale, if retired for compliance by PG&E, would be expected to meet the definition of PCC 1 as described in Pub. Util. Code Section 399.16(b)(1). However, PG&E was unable to provide the certification that buyers requested because any such determination is outside of PG&E's control. The Commission determines the applicable PCC category of RPS products used by retail sellers to meet RPS compliance requirements in a process that is independent from, and later in time from, the process to review and approve a contract executed by PG&E for the sale of RPS volumes. Given the request presented to PG&E, PG&E believes that it would facilitate the sale of bundled RPS volumes if the Commission determined the PCC of the products as to the purchasing

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62 D.17-12-007, OP 7; D.14-11-042, p. 77.

entity in connection with the Advice Letter approval process to review the sales agreement.

10.A.4.2 Product Term

In 2018, PG&E sought sales with energy deliveries over multiple years rather than in a single year as it had previously solicited in 2017. Buyers were receptive to the extended term of energy deliveries in the 2018 RPS Sales Solicitation and conveyed their preference sales for multiple years rather than single years. In 2019, PG&E will continue to solicit sales with deliveries across multiple years.

10.A.4.3 Timing and Timeline of Solicitation

[redacted]

To address these concerns PG&E will conduct future solicitations in a very streamlined manner, and intends to target issuing three, with a minimum of two, solicitations during calendar year 2020. PG&E aims to issue its first 2020 RPS Sales Solicitation shortly after the 2019 RPS Plan has received final approval from the CPUC.

10.A.4.4 Execution Process

In future short-term sales solicitations, PG&E will identify in advance which areas of the sales agreement are eligible to be discussed. Using the standardized form of agreement developed in 2018, PG&E engaged in limited discussions with buyers in 2019. [redacted] As a result, PG&E expects discussions with buyers on the short-term sales agreement to be minimal in 2020 to streamline the execution process.

10.B. Bid Selection Protocols

PG&E has included in Section 10.A, above, a description of the Framework that PG&E proposes to use to evaluate sales from its existing RPS portfolio. The Framework itself is included in Appendix F. The Commission has approved a similar framework in prior RPS Plans. PG&E has included a solicitation protocol and pro forma sales agreement as Appendix E to this 2019 RPS Plan. The pro forma sales agreement is based on the Edison Electric Institute ("EEI") Master Agreement and is consistent with the form agreement that PG&E used in its 2019 RPS Sales Solicitation. The protocol and form of sales agreement incorporate lessons learned from the 2019 RPS Sales Solicitation, as previously described in this section.

PG&E anticipates that minimal negotiations will be needed with respect to the form sales agreement and proposes filing any executed short-term sales agreements by a Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[63] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under two years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to occur in 2020.

10.C. LCBF Criteria

Although PG&E is not planning for a RPS procurement solicitation, PG&E recognizes that the most recent detailed description of its LCBF methodology, including the NMV and PAV methodologies, has continued to be used as a reference for procurement valuation for mandated programs. Accordingly, as part of this 2019 RPS Plan, PG&E is providing an update to the LCBF methodology approved in its 2018 RPS planning cycle to better reflect current market and portfolio conditions. PG&E's updates to the quantitative LCBF Protocol are minor, and are solely focused on refinements to

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63 D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

calculating congestion and losses, and updating those results. The revised version of PG&E's detailed explanation of its LCBF methodology is included as Appendix G to this 2019 RPS Plan. A redline showing this revised version of the LCBF methodology against the last Commission-approved version (from PG&E's 2018 RPS Plan) is provided for convenience at Appendix K~~J~~ to this 2019 RPS Plan.

10.C.1. Informational-Only Time of Delivery Factors

PG&E historically set the TOD factors in its RPS procurement contracts based on expected (internally forecasted) hourly prices, load forecasts, and capacity values.

In PG&E's review of the TOD factors for the~~is~~ 2018 RPS Plan, PG&E determined that it has been increasingly difficult to accurately forecast TOD preferences within even the next decade, let alone for the duration of a typical RPS PPA (e.g., 20 years), given California's quickly evolving energy mix, policies, and markets.

PG&E determined that TOD factors in a long-term PPA are unlikely to reflect system need over the entire life of the PPA. In fact, changes in the State's net load over time could result in TOD factors incentivizing production under a PPA at times in which the PPA contributes to overgeneration problems, rather than helps to solve them.

Given the reasons outlined above, PG&E eliminated TOD factors for any new RPS procurement contracts that may be executed in the future, including in new contracts to be executed in existing mandatory procurement programs, such as BioMAT. However, pursuant to D.19-02-007, PG&E ~~has~~ calculated TODs for informational purposes only, in order to communicate to developers when energy deliveries might be more valuable to the system and allow developers to respond with optimized project designs and bids.[64] PG&E's proposed informational-only TOD factors were served on the R.18-07-003 service list on May 29, 2019, in compliance with D.19-02-007.[65]

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64 D.19-02-007, OP 16.

65 *Id.,* OP 17.

Subsequently, the Commission issued D.19-42-042, ordering that informational-only TOD factors be included in PG&E's final 2019 RPS plan~~s~~ based on the most recent inputs available.[66] Appendix J contains updated informational-only TOD factors based on Marginal Energy Costs ("MEC") contained in workpapers developed in Phase II of PG&E's 2020 General Rate Case (A.19-11-019), and are subject to Commission approval. The MEC workpapers are proprietary because MEC workpapers contain complex models developed by PG&E. In contrast, informational-only TOD factors provided as Appendix J are publicly available because those factors are based on aggregated data. ~~These proposed~~ Updated informational-only TOD factors are also available online under "Renewables Portfolio Standard (RPS)" at http://www.pge.com/rfo. PG&E anticipates that any updates to informational-only TOD factors will be posted to that website.

10.C.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include "the employment growth associated with the construction and operation of eligible renewable energy resources."[67]

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E's LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E's assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California

66 D.19-42-042, OP 26.

67 Pub. Util. Code § 393.13(a)(4)(A)(iv).

for the proposed project. This information was required from bidders in PG&E's 2014 RPS RFO.[68]

10.C.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."[69]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from participants similar to what was required in the 2014 RPS RFO.[70] PG&E asked participants to respond to the following questions on this topic:

Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the participant is encouraged to describe in its offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:

- Projected hires from adjacent community (number and type of jobs),
- Duration of work (during construction and operation phases),

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68 Appendix J2 to 2014 RPS RFO Protocol.

69 Pub. Util. Code § 399.13(a)(7).

70 Appendix J2 to 2014 RPS RFO Protocol.

- Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
- Emissions reduction – Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
  - If “yes”, provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).
  - If “No”, why not?

11. Consideration of Price Adjustment Mechanisms

The 2019 RPS Plan Ruling requires each IOU to “describe how price adjustments (e.g., index to key components, index to Consumer Price Index (“CPI”), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date.”[71]

In this 2019 RPS Plan, PG&E is proposing to not hold an RPS procurement solicitation in this 2019 RPS Plan cycle. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. 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.[72] In order to

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[71] 2019 RPS Plan Ruling, p. 19.

[72] Pub. Util. Code § 399.11(b)(5).

maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined, agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[73]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource and is instead linked to increases in prices of oil and natural gas, food, medical care, and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

12. Curtailment Frequency, Cost, and Forecasting

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Plans how "expected economic curtailment affects their RPS procurement."[74] In addition, the Commission directed the IOUs to report on observations and issues

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73 D.11-04-030, pp. 33-34.

74 D.14-11-042, p. 45.

related to economic curtailment, including periodic reporting to the Procurement Review Group.[75]

In response to the specific requests for information related to curtailment included in the 2019 RPS Plan Ruling, PG&E provides the following information:

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

As the CAISO has stated:

> A swift rise in California's renewable energy capacity, especially solar generation, is the main driver behind the growing occurrence of oversupply…. Currently, the ISO's most effective tool for managing oversupply is to "curtail" renewable resources. That means plant generation is scaled back when there is insufficient demand to consume production…. Curtailments can occur in three ways: economic curtailment, when the market finds a home for low-priced or negative-priced energy; self-scheduled cuts, which reduce generation from self-scheduled bids; and exceptional dispatch, when the ISO orders generators to turn down output."[76]

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

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

One approach is to use the statistical model that PG&E uses to develop forward prices. Using recent historical data, a regression is run to develop the relationship between fundamental market drivers and observed market Day Ahead prices. The fundamental drivers include gas costs, GHG compliance instrument costs, expected volume of must-take energy, and characteristics of flexible resources on the grid. Once that relationship is developed, PG&E forecasts the fundamental drivers forward, and applies the derived relationships to those forecasts to estimate prices. As more

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75 *Id.*, pp. 42-43.

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

renewables are forecast to be added to the grid in coming years, PG&E expects more forward prices to be negative.

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

To the extent that it is contractually and operationally able to do so, PG&E has bid RPS-eligible resources in its portfolio into the CAISO markets. When there are negative prices in the CAISO market, these resources may be economically curtailed given their bid price. Economic-based curtailments awarded during negative price periods have created direct and indirect benefits for PG&E's customers and the CAISO.

PG&E started Day-Ahead economic bidding for RPS-eligible resources in February 2014 and subsequently initiated Real-Time economic bidding in September 2014. PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. [redacted] PG&E provided more detail concerning its RPS bidding strategy in its Bundled Procurement Plan[77] which was approved by the Commission in D.15-10-031.

While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods, and also improving CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events. The overall trends in both the frequency and magnitude of negative prices in recent years suggests that the CAISO is able to generally balance supply and demand using economic curtailment rather than administratively curtailing generation.

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

[77] *See* PG&E 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

There were no incidences of overgeneration, as this term is defined by the CAISO, in 2018. The ability for the CAISO to control renewable output through economic curtailment is a key tool in preventing overgeneration.

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

Regarding longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. For a discussion of forecasted curtailment levels please see Section 7.2.3. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

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 oversupply events.

13. Cost Quantification

This section summarizes actual and forecasted RPS generation costs. Table 2 outlines the information utilities are required to include in the Cost Quantification Template made available by the Commission on its website. The resulting data are shown in Tables 1 through 4 of Appendix B. Page 1 of Appendix B outlines the methodology for calculating the costs and generation.

TABLE 2
RPS PROCUREMENT AND SALES INFORMATION RELATED TO COST QUANTIFICATION

Row	Item	Description
1.	Actual Direct Expenditures and Revenue – per year	Total dollars expended and received for all REC transactions for every year from 2003 to present year. Figures shall be reported by resource and technology type and reported for each year.
2.	Actual REC Procurement (MWh) – per year	Total REC procurement for every year from 2003 to present year, including any REC sales. Amounts shall be reported by resource and technology type and reported for each year.
3.	Forecast Direct Expenditures and Revenue – per year	Total forecasted dollars expended and received for all REC transactions to date (and approved to date for the utilities). Forecasts Direct Expenditures shall be reported by resource and technology type and reported for each year from 2018-2030.
4.	Forecast REC Procurement (MWh) – per year	Total forecasted REC procurement to date (and approved to date for the utilities), including any planned REC sales. Forecasts shall be reported by resource and technology type and reported for each year.
5.	I Annual Average RPS rates ($/kWh)	Total actual and forecasted annual utility RPS generation and procurement costs divided by bundled load from 2003-2030.

13.1 RPS Cost Impacts

Appendix B quantifies the cost of RPS-eligible procurement—both historical (2003-2018) and forecast (2019-2030). PG&E's annual RPS-eligible procurement and generation costs rose sharply from 2003 through 2015, from $523 million to more than $2.4 billion in those years, respectively. However, since 2015 PG&E's RPS-eligible procurement and generation costs have stabilized around $2.4 billion per year. On a forward-looking basis (2019-2030), PG&E's RPS portfolio costs are expected to average about $2.35 billion. The somewhat lower costs over the first part of forecast period are primarily due to greater anticipated RPS sales revenue.

On the other hand, the average RPS rates shown in Appendix B rise steadily through the first half of the forecast period and then decline gradually through 2030. This is largely a result of the underlying bundled load forecast which declines in the first part of the forecast due continued anticipated CCA growth and then gradually increases due to anticipated increases in electric vehicle usage. Because the rates calculated in the Cost Quantification Template do not reflect allocated costs to departed load (e.g., DA and CCA customers), these illustrative rates will overestimate the actual impacts on forecasted bundled rates.

13.2 Cost Impacts Due to Mandated Programs

The cost impacts of mandated procurement programs that focus on particular technologies or project size have comprised an increasing share of PG&E's incremental procurement in recent years, to the extent that incremental procurement is now entirely mandated by Commission programs.

In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms, like technology targets that allow only a subset of those options.[78] Studies have also shown that renewable electricity mandates increase prices and costs,[79] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by

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78 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at https://www.rff.org/publications/working-papers/cost-effectiveness-of-renewable-electricity-policies/); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

79 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call"; Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

disqualifying those less expensive participants; and second, by creating a less robust market for participants to compete.[80] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location, and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

14. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's 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), this section is divided into separate discussions addressing each of these situations.

14.1 Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2019 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its

80 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at https://www.rff.org/publications/journal-articles/combining-policies-for-renewable-energy-is-the-whole-less-than-the-sum-of-its-parts/.)

own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct sets the standard that PG&E employees will put safety first.[81] PG&E's commitment to a safety-first culture is reinforced by a speak-up culture.[82] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

The top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E 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 CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance ("O&M") 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.

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81 *See* PG&E, "Employee Code of Conduct" (February 2018) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 4 (available at https://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/SupplierCodeofConductPGE.pdf).

82 *See* PG&E, "Employee Code of Conduct" *supra*, p. 21 *et seq.*

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

Regarding employee safety, 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. Employees also participate in activities developed and conducted by an employee-led Driver Awareness Team established for the sole purpose of improving driving safety.

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
- Contractor Safety Oversight Program,
- Training and recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- 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
- Near Hit (close call) reporting
- Employee injury case management
- Safety performance recognition
- Public safety awareness
- Corrective Actions Program

The safety focus of PG&E's hydroelectric operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our 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. Regarding public safety, PG&E has developed and implemented a comprehensive public safety program that includes: (1) Dam Safety program; (2) public education, outreach, and partnership with key agencies; (3) improved warning and hazard signage at hydro facilities; (4) enhanced emergency response preparedness, training, drills, and coordination with emergency response organizations; and (5) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E's Dam Safety Program is responsible for ensuring the long-term safe and reliable operation of PG&E's dams by all company personnel, and for ensuring that power production or other business objectives do not take precedence over dam safety or regulatory compliance. PG&E's dams are regulated by both the Federal Energy Regulatory Commission ("FERC") and the California Department of Water Resources Division of Safety of Dams ("DSOD"). PG&E's Dam Safety Program was developed in line with FERC requirements. The Dam Safety Program's objectives include the following:

- Maintaining a well-trained and resourced organization, with a primary focus on public and employee safety as well as compliance with FERC and DSOD requirements for dam safety;
- Communicating policies and expectations regarding dam safety and regulatory compliance to all Dam Safety Program team members, O&M personnel, and other stakeholders;
- Defining protocols for communicating and reporting dam safety issues;
- Defining the responsibilities and authority of the Chief Dam Safety Engineer;
- Providing and implementing a comprehensive training plan for dam safety, formal dam safety quality assurance and quality control programs, and a dam safety inspection program; and

- Requiring internal and external audits and assessments to verify and document compliance and maintain an ongoing focus on dam safety and regulatory compliance.

To carry out these objectives, the Dam Safety Program provides engineering and other construction support and analysis, inspection services, dam surveillance and monitoring services, maintenance procedures and emergency action plans, dam security, and the development of other safety-related standards and procedures. The Dam Safety Program also convenes and seeks the input of an independent Dam Safety Advisory Board consisting of industry experts in dam safety.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as arc flash hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that acts to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

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

The vast majority of PG&E's 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. PG&E's contract provisions reinforce the developer's obligations to safety by requiring them 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, PG&E's recent energy storage contract provisions seek to instill a continuous improvement safety culture that mirrors PG&E's "Contractor Safety Standard" pursuant to D.15-07-014. These provisions require developers to demonstrate their use of safeguards, equipment, and personnel training, and require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. Such provisions were included in the executed agreements arising out of the 2014 and 2016 Energy Storage RFOs and could be incorporated in future RPS contracts if PG&E's RPS position resulted in a need for RPS procurement. The safety related contract provisions within PG&E's form RPS contracts may be further modified in a future RPS procurement solicitation to include safety contract provisions similar to those included in PG&E's previous energy storage contracts if any specific projects are expected to pose elevated safety risks, based on PG&E's review of factors such as the generation technology's risk profile, proximity of any projects to sensitive locations, or other project specific considerations.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

15. Comments on Coordination with Integrated Resource Planning Proceeding

PG&E supports close alignment between the IRP proceeding[83] and the RPS proceeding, with the IRP comparing RPS resources against other GHG-free resources, including demand-side alternatives such as EE and rooftop solar. In light of the overlap in reporting requirements between the RPS and IRP proceedings, the 2019 RPS Plan Ruling proposed a process in which annual RPS filing requirements can be satisfied by the LSEs' filing of their IRP Plans in the years that IRP Plans are required.[84] The Commission sought comments from parties on the proposal, and those comments will be submitted after the filing of this Draft 2019 RPS Plan.[85]

In accordance with the 2019 RPS Plan Ruling, PG&E expects to file opening and reply comments on the proposal to better integrate the IRP and RPS Plan proceedings. PG&E will then summarize in this Section of its Final, Conforming 2019 RPS Plan any order by the Commission in its decision on the Draft 2019 RPS Plans with regard to future RPS and IRP coordination.

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83 The current IRP proceeding is R.16-02-007.

84 2019 RPS Plan Ruling, pp. 24-26.

85 *Id.*, p. 24; Attach. A.

Appendix ~~G~~F

Framework for Assessing Potential Sales of ~~Surplus~~ RPS Volumes

Confidentiality Protected Under D.06-06-066 Appendix 1
or PU Code Section 454.5(g)

Appendix F – Framework for Assessing Potential Sales of Renewables Portfolio Standard Volumes

This Appendix describes Pacific Gas and Electric Company's ("PG&E") framework (the "Sales Framework") for assessing whether to hold or sell Renewables Portfolio Standard ("RPS") volumes and only applies to RPS sales with deliveries up to two years forward. This Appendix F framework governs only PG&E's sales that are approved as part of the 2019 RPS Plan. For purposes of clarity, Appendix H to this Plan, which governs other sales of Tree Mortality Non-Bypassable Charge Renewable Energy Credits, does not apply to the Bundled RPS Energy Solicitation(s) governed by the 2019 RPS Plan. This Sales Framework will be updated each year as part of the RPS Plan filing. PG&E may therefore annually adjust its methodology and the resulting calculations of volumes for sale.

[redacted]

Determine Volume Limits:

PG&E will use the Sales Framework to establish which bids it will execute, if any, in its Bundled RPS Energy Solicitation(s) governed by the 2019 RPS Plan. Specifically, this Framework establishes [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The Annual Limits and Solicitation Limits will be re-calculated for each solicitation, adjusting for volumes executed in prior solicitations.[3]

- PG&E will target issuing three, with a minimum of two, solicitations per year[4]
- PG&E will utilize the protocol included at Appendix E.1 of this 2019 RPS Plan and will execute sales based on the pro forma sales agreement contained in Appendix E.3 PG&E will show any necessary changes to the pro forma sales agreement in a redline filed with its Advice Letter seeking approval of executed sales agreements.
- PG&E intends to sell all volumes through PG&E-issued solicitations.
- PG&E will consider price offered as the sole quantitative criterion.

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1 These annual RPS compliance targets are those established by the California Public Utilities Commission ("Commission") in relevant decision for each year of each multi-year RPS compliance periods in order to calculate the total Procurement Quantity Requirement for each such compliance period.

2 The annual limits will incorporate the amount of volume that PG&E is able to deliver both contractually and physically.

3 Any recalculation will account for any volume sold in prior solicitations.

4 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations is dependent upon the outcome of prior solicitations and/or changes to PG&E's RPS position.

- PG&E retains the discretion, subject to CPUC review, to decline to accept any offers arising out of a sales solicitation and/or to discontinue any sales solicitation under any circumstances in which there is evidence of market manipulation.

APPENDIX I

Glossary of Acronyms and Abbreviations

TABLE OF ACRONYMS

Acronym	Full Name
2019 RPS Plan	Draft 2019 Renewables Portfolio Standard Plan
A.	Application
AB	Assembly Bill
ADR	Alternative Dispute Resolution
AL	Advice Letter
ALJ	Administrative Law Judge
A/S	Ancillary Services
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Bioenergy Renewable Auction Mechanism
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPI	Consumer Price Index
CPUC or Commission	California Public Utilities Commission
D.	Decision
DA	Direct Access
DAC-GT	Disadvantaged Communities Green Tariff
DACs	disadvantaged communities
DSOD	Division of Safety of Dams
EE	energy efficiency
EEI	Edison Electric Institute
ESP	Electric Service Provider
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
GEP	Guaranteed Energy Production
GHG	greenhouse gas
GTSR	Green Tariff Shared Renewables
GWh	gigawatt-hour
ID&WA	Irrigation District and Water Agency
IDWA	Irrigation District Water Authority
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
IRP	Integrated Resources Plan
ITC	Investment Tax Credit

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
LCBF	least-cost, best-fit
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MEC	Marginal Energy Costs
MMoP	Minimum Margin of Procurement
MW	megawatt
MWh	Megawatt-hour
NMV	Net Market Value
NPV	Net Present Value
OIR	Order Instituting Rulemaking
O&M	operations and maintenance
OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
PAV	Portfolio Adjusted Value
PCC	portfolio content category
PCIA	Power Charge Indifference Adjustment
PEL	Procurement Expenditure Limitation
PG&E	Pacific Gas and Electric Company
POR	Plan of Reorganization
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PQRs	Procurement Quantity Requirements
PRG	Procurement Review Group
PSP	Preferred System Portfolio
PTC	Production Tax Credit
PTO	Participating Transmission Owner
Pub. Util. Code	Public Utilities Code
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PV RAM	Photovoltaic Program - RAM
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
Res.	Resolution
RFO	Request for Offer
RICA	renewable integration cost adder
RNS	Renewable Net Short
RPS	Renewables Portfolio Standard
SB	Senate Bill
SONS	stochastically-optimized net short
TM NBC	Tree Mortality Non-Bypassable Charge
TOD	Time of Delivery
UOG	Utility-Owned Generation
VMOP	Voluntary Margin of Procurement
WREGIS	Western Renewable Energy Generation Information System
YCWA	Yuba County Water Agency

APPENDIX J

Informational-Only TOD Factors

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.22	1.13	1.09	1.10	1.19	1.37	1.63	1.58	1.08	0.65	0.42	0.37	0.36	0.40	0.53	0.86	1.44	2.19	2.43	2.16	1.95	1.78	1.56	1.35
2	1.11	1.01	0.97	0.99	1.11	1.33	1.61	1.38	0.77	0.31	0.12	0.08	0.08	0.14	0.26	0.50	1.01	1.89	2.35	2.17	1.93	1.70	1.48	1.26
3	1.04	0.91	0.86	0.86	0.93	1.10	1.34	1.18	0.58	0.13	0.01	0.00	0.00	0.00	0.01	0.08	0.32	0.90	1.62	2.06	1.96	1.73	1.49	1.24
4	0.94	0.79	0.73	0.71	0.78	0.97	1.21	0.77	0.20	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.43	1.13	1.86	2.06	1.76	1.50	1.20
5	1.00	0.82	0.74	0.73	0.80	1.00	0.95	0.47	0.12	0.01	0.00	0.00	0.00	0.00	0.03	0.15	0.42	0.77	1.29	1.83	2.17	1.92	1.58	1.26
6	0.94	0.81	0.73	0.72	0.79	0.98	0.80	0.44	0.18	0.08	0.07	0.09	0.13	0.23	0.40	0.64	0.96	1.23	1.55	1.89	2.29	1.95	1.55	1.21
7	1.10	1.01	0.94	0.92	0.98	1.11	1.10	0.82	0.54	0.38	0.39	0.51	0.68	0.91	1.15	1.41	1.77	2.20	2.46	2.80	2.99	2.09	1.63	1.34
8	1.14	1.03	0.97	0.95	1.00	1.15	1.28	1.01	0.66	0.44	0.42	0.56	0.74	0.98	1.21	1.44	1.69	1.96	2.28	3.11	2.79	2.06	1.62	1.35
9	1.11	1.01	0.96	0.93	0.97	1.11	1.32	1.13	0.69	0.39	0.31	0.39	0.51	0.70	0.92	1.18	1.43	1.68	2.20	2.74	2.28	1.84	1.53	1.29
10	1.13	1.01	0.95	0.93	0.97	1.09	1.31	1.30	0.79	0.37	0.20	0.18	0.21	0.30	0.46	0.69	1.04	1.49	2.17	2.21	1.93	1.73	1.53	1.31
11	1.11	1.05	1.02	1.04	1.10	1.24	1.40	1.13	0.71	0.41	0.31	0.28	0.30	0.38	0.59	0.94	1.54	2.06	2.20	1.94	1.76	1.58	1.41	1.24
12	1.21	1.13	1.09	1.10	1.17	1.31	1.52	1.45	1.07	0.74	0.56	0.50	0.47	0.53	0.69	1.04	1.65	2.24	2.32	2.04	1.86	1.69	1.51	1.35

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.21	1.13	1.08	1.04	1.05	1.10	1.28	1.19	0.56	0.18	0.07	0.06	0.05	0.06	0.12	0.43	1.22	1.99	2.25	2.04	1.83	1.69	1.52	1.30
2	1.11	1.00	0.95	0.93	0.96	1.03	1.21	0.84	0.26	0.02	0.00	0.00	0.00	0.00	0.00	0.06	0.60	1.72	2.19	2.03	1.83	1.63	1.44	1.21
3	1.01	0.86	0.81	0.77	0.80	0.90	1.03	0.68	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.65	1.47	1.93	1.85	1.63	1.42	1.19
4	1.00	0.83	0.73	0.69	0.70	0.81	0.87	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.90	1.73	1.95	1.69	1.43	1.16
5	0.99	0.77	0.69	0.64	0.67	0.78	0.47	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.35	0.97	1.66	2.04	1.81	1.48	1.17
6	0.97	0.83	0.74	0.70	0.72	0.80	0.41	0.07	0.00	0.00	0.00	0.00	0.02	0.03	0.07	0.20	0.52	0.90	1.36	1.77	2.15	1.85	1.49	1.17
7	1.12	1.02	0.94	0.88	0.89	0.95	0.74	0.26	0.07	0.03	0.05	0.10	0.17	0.34	0.59	0.91	1.26	1.68	2.13	2.51	2.69	1.97	1.59	1.30
8	1.15	1.01	0.96	0.90	0.91	0.99	0.97	0.41	0.10	0.04	0.04	0.09	0.19	0.37	0.60	0.93	1.29	1.60	1.90	2.43	2.38	1.92	1.56	1.30
9	1.10	0.98	0.91	0.86	0.87	0.94	1.05	0.61	0.13	0.02	0.02	0.04	0.09	0.19	0.39	0.73	1.07	1.43	1.92	2.33	2.04	1.72	1.46	1.25
10	1.14	1.01	0.95	0.91	0.91	0.98	1.10	0.94	0.25	0.04	0.00	0.00	0.00	0.01	0.06	0.21	0.61	1.25	1.96	2.03	1.79	1.62	1.46	1.28
11	1.12	1.03	0.99	0.98	1.00	1.05	1.13	0.70	0.25	0.06	0.01	0.01	0.02	0.06	0.22	0.62	1.37	1.89	2.05	1.82	1.66	1.52	1.36	1.21
12	1.21	1.12	1.08	1.06	1.07	1.12	1.26	1.16	0.67	0.34	0.18	0.14	0.12	0.14	0.31	0.72	1.48	2.04	2.18	1.91	1.76	1.64	1.49	1.34

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.26	1.18	1.13	1.14	1.21	1.36	1.61	1.54	0.97	0.45	0.22	0.18	0.17	0.22	0.37	0.76	1.43	2.25	2.52	2.21	1.97	1.80	1.59	1.38
2	1.17	1.08	1.03	1.04	1.14	1.33	1.58	1.32	0.61	0.15	0.04	0.03	0.04	0.05	0.12	0.39	0.98	1.90	2.40	2.20	1.95	1.72	1.52	1.32
3	1.11	0.98	0.92	0.91	0.97	1.12	1.33	1.14	0.45	0.04	0.00	0.00	0.00	0.00	0.00	0.03	0.23	0.85	1.63	2.08	1.98	1.74	1.52	1.30
4	1.02	0.86	0.79	0.77	0.82	0.98	1.19	0.68	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.32	1.12	1.87	2.06	1.77	1.52	1.26
5	1.00	0.81	0.72	0.69	0.76	0.95	0.84	0.26	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.15	0.53	1.18	1.79	2.14	1.89	1.55	1.26
6	1.01	0.88	0.79	0.76	0.82	0.99	0.76	0.31	0.06	0.01	0.01	0.01	0.03	0.06	0.13	0.31	0.68	1.05	1.47	1.90	2.41	1.97	1.57	1.27
7	1.17	1.08	1.00	0.97	1.02	1.14	1.10	0.74	0.36	0.17	0.13	0.19	0.33	0.54	0.83	1.14	1.55	2.06	2.47	3.09	3.65	2.23	1.67	1.39
8	1.23	1.12	1.06	1.03	1.06	1.19	1.30	0.98	0.52	0.23	0.17	0.25	0.40	0.64	0.92	1.21	1.53	1.91	2.51	4.50	3.69	2.24	1.68	1.42
9	1.22	1.13	1.08	1.05	1.07	1.18	1.36	1.15	0.64	0.25	0.13	0.16	0.25	0.46	0.70	1.01	1.32	1.65	2.53	3.93	2.83	1.99	1.60	1.38
10	1.24	1.13	1.07	1.05	1.07	1.17	1.35	1.32	0.76	0.26	0.07	0.04	0.06	0.13	0.29	0.56	0.99	1.49	2.42	2.50	2.09	1.81	1.60	1.40
11	1.20	1.15	1.12	1.13	1.18	1.29	1.42	1.13	0.65	0.29	0.17	0.14	0.17	0.27	0.50	0.93	1.57	2.26	2.45	2.10	1.85	1.65	1.47	1.32
12	1.30	1.22	1.18	1.19	1.24	1.35	1.54	1.46	1.05	0.65	0.45	0.38	0.37	0.45	0.64	1.06	1.70	2.47	2.59	2.20	1.97	1.77	1.58	1.43

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.26	1.18	1.13	1.08	1.08	1.12	1.27	1.17	0.47	0.08	0.04	0.03	0.02	0.04	0.06	0.36	1.22	2.01	2.27	2.05	1.83	1.70	1.54	1.35
2	1.17	1.07	1.02	0.99	1.00	1.05	1.21	0.80	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.04	0.57	1.73	2.20	2.04	1.83	1.64	1.47	1.28
3	1.08	0.94	0.88	0.84	0.86	0.93	1.04	0.64	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.62	1.49	1.94	1.85	1.65	1.45	1.25
4	1.07	0.90	0.81	0.75	0.75	0.83	0.86	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.90	1.74	1.95	1.70	1.45	1.22
5	0.99	0.76	0.67	0.60	0.62	0.71	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.85	1.62	1.99	1.77	1.46	1.17
6	1.02	0.87	0.78	0.72	0.72	0.80	0.36	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.25	0.68	1.26	1.77	2.20	1.85	1.50	1.21
7	1.19	1.09	1.01	0.94	0.94	0.98	0.75	0.21	0.02	0.00	0.00	0.01	0.02	0.08	0.27	0.59	1.01	1.56	2.05	2.59	2.96	2.04	1.62	1.35
8	1.22	1.09	1.04	0.98	0.97	1.04	1.01	0.39	0.05	0.00	0.00	0.00	0.02	0.11	0.30	0.63	1.06	1.48	1.91	2.76	2.64	1.98	1.60	1.36
9	1.22	1.10	1.04	0.99	0.98	1.04	1.13	0.67	0.11	0.00	0.00	0.00	0.01	0.06	0.20	0.54	0.96	1.39	2.01	2.71	2.24	1.80	1.53	1.34
10	1.24	1.13	1.08	1.03	1.03	1.07	1.17	1.00	0.24	0.03	0.00	0.00	0.00	0.00	0.00	0.14	0.58	1.26	2.05	2.13	1.86	1.67	1.52	1.37
11	1.21	1.14	1.10	1.08	1.09	1.12	1.19	0.75	0.21	0.02	0.00	0.00	0.01	0.02	0.16	0.64	1.40	1.97	2.16	1.90	1.72	1.58	1.43	1.29
12	1.30	1.22	1.18	1.16	1.16	1.19	1.31	1.20	0.66	0.27	0.13	0.09	0.07	0.10	0.28	0.76	1.53	2.14	2.30	1.99	1.83	1.70	1.56	1.42

Pacific Gas & Electric (PG&E) (2020 GRC Phase II) Information only (Non-Confidential) TOD factors

PG&E -WD	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.28	1.20	1.15	1.15	1.21	1.34	1.57	1.51	0.95	0.40	0.17	0.13	0.13	0.17	0.32	0.75	1.43	2.33	2.66	2.30	2.01	1.81	1.61	1.40
2	1.20	1.11	1.06	1.06	1.14	1.32	1.55	1.31	0.59	0.12	0.05	0.03	0.04	0.06	0.11	0.38	1.01	1.92	2.48	2.25	1.97	1.73	1.54	1.35
3	1.15	1.02	0.96	0.95	0.99	1.12	1.31	1.12	0.44	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.23	0.88	1.67	2.13	2.00	1.75	1.53	1.33
4	1.08	0.93	0.86	0.82	0.86	0.99	1.17	0.69	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.36	1.18	1.89	2.09	1.78	1.54	1.31
5	1.08	0.90	0.80	0.76	0.81	0.97	0.86	0.28	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.56	1.24	1.81	2.18	1.90	1.57	1.31
6	1.09	0.95	0.85	0.82	0.87	1.01	0.79	0.32	0.04	0.00	0.00	0.00	0.01	0.03	0.08	0.22	0.61	1.03	1.51	2.02	2.65	2.03	1.59	1.31
7	1.22	1.12	1.05	1.01	1.04	1.14	1.11	0.75	0.33	0.12	0.06	0.08	0.17	0.38	0.67	1.01	1.48	2.05	2.68	3.81	4.81	2.46	1.71	1.42
8	1.25	1.13	1.07	1.03	1.06	1.17	1.27	0.96	0.45	0.14	0.07	0.09	0.20	0.41	0.72	1.06	1.42	1.89	2.76	5.65	4.71	2.39	1.69	1.43
9	1.19	1.10	1.04	1.00	1.02	1.12	1.29	1.07	0.50	0.11	0.02	0.03	0.07	0.20	0.47	0.82	1.20	1.58	2.66	4.64	3.10	2.00	1.58	1.36
10	1.21	1.10	1.03	1.00	1.01	1.11	1.28	1.24	0.65	0.13	0.00	0.00	0.00	0.02	0.13	0.39	0.88	1.44	2.47	2.59	2.11	1.79	1.57	1.37
11	1.17	1.11	1.07	1.08	1.12	1.23	1.35	1.06	0.52	0.17	0.08	0.06	0.07	0.13	0.36	0.84	1.52	2.29	2.52	2.12	1.83	1.62	1.44	1.29
12	1.26	1.17	1.13	1.13	1.17	1.28	1.47	1.39	0.95	0.49	0.29	0.23	0.22	0.29	0.50	0.98	1.65	2.52	2.68	2.22	1.96	1.73	1.55	1.39

PG&E -WE/Hol	Hour Ending																							
Month\ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.28	1.20	1.15	1.10	1.09	1.11	1.25	1.16	0.45	0.07	0.03	0.02	0.02	0.03	0.07	0.35	1.23	2.03	2.31	2.07	1.84	1.71	1.55	1.38
2	1.21	1.10	1.05	1.02	1.01	1.05	1.20	0.81	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.05	0.63	1.73	2.22	2.05	1.84	1.65	1.49	1.31
3	1.12	0.99	0.93	0.88	0.89	0.95	1.04	0.66	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.64	1.52	1.95	1.85	1.65	1.47	1.29
4	1.13	0.97	0.87	0.81	0.79	0.85	0.87	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.98	1.76	1.97	1.71	1.48	1.28
5	1.07	0.86	0.76	0.68	0.68	0.75	0.41	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.94	1.64	2.01	1.79	1.49	1.24
6	1.09	0.95	0.85	0.79	0.77	0.83	0.40	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.20	0.67	1.30	1.86	2.36	1.88	1.52	1.26
7	1.24	1.13	1.05	0.98	0.97	1.00	0.78	0.21	0.02	0.00	0.00	0.01	0.00	0.03	0.14	0.45	0.91	1.60	2.07	2.85	3.37	2.14	1.64	1.39
8	1.25	1.12	1.06	1.00	0.98	1.03	1.00	0.38	0.03	0.00	0.00	0.00	0.00	0.02	0.16	0.46	0.94	1.44	1.98	3.19	2.96	2.04	1.61	1.39
9	1.19	1.07	1.00	0.94	0.93	0.97	1.05	0.58	0.05	0.00	0.00	0.00	0.00	0.00	0.06	0.33	0.82	1.31	2.00	2.87	2.28	1.78	1.50	1.32
10	1.22	1.10	1.04	0.98	0.97	1.00	1.09	0.92	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.46	1.21	2.02	2.12	1.83	1.64	1.49	1.34
11	1.18	1.10	1.06	1.03	1.03	1.05	1.11	0.65	0.12	0.00	0.00	0.00	0.00	0.01	0.07	0.54	1.34	1.95	2.15	1.88	1.69	1.55	1.40	1.26
12	1.26	1.17	1.13	1.10	1.09	1.12	1.23	1.12	0.54	0.17	0.05	0.03	0.03	0.04	0.19	0.66	1.48	2.12	2.30	1.98	1.80	1.66	1.52	1.38