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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS: SOUTHERN CALIFORNIA EDISON COMPANY (U-338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

JANET S. COMBS
RUSSELL A. ARCHER
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
626.302.1524
Janet.Combs@sce.com

Attorneys for SOUTHERN CALIFORNIA EDISON COMPANY

EVELYN KAHL
ANN C. SPRINGGATE
BUCHALTER, A PROFESSIONAL CORPORATION
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

MICHAEL B. DAY
GOODIN, MACBRIDE, SQUERI & DAY, LLP
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: mday@goodinmacbride.com

Attorneys for COMMERCIAL ENERGY OF CALIFORNIA

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I.

<u>INTRODUCTION</u>

Pursuant to the Phase 2 Scoping Memo and Ruling of Assigned Commissioner, issued February 1, 2019 ("Phase 2 Scoping Memo"), Southern California Edison Company ("SCE"), on behalf of itself, California Community Choice Association ("CalCCA"), and Commercial Energy ("Commercial") (together, the "Co-Chairs"), respectfully files this final report on Working Group Three: Portfolio Optimization and Cost Reduction, and Allocation and Auction ("WG 3") (the "Final Report").[1]

II.

<u>EXECUTIVE SUMMARY</u>

Pursuant to the Phase 2 Scoping Memo of Rulemaking ("R.") 17-06-026, the WG 3 Co-Chairs are directed to address the following four issues relating to the treatment and management of excess resources in the investor-owned utilities' ("IOU") Power Charge Indifference

[1] Pursuant to CPUC Rule 1.8(d), CalCCA and Commercial have authorized SCE to file this Final Report on their behalf.

Adjustment-eligible and Competition Transition Charge ("CTC")-eligible (collectively "PCIA") portfolios:

(1) Proposed new structures, processes, and rules governing portfolio optimization, and how these processes and rules should be structured so as to be compatible with other proceedings;

(2) Adoption of additional standards for more active management of IOU portfolios in response to departing load;

(3) How a transition to implement new standards should occur; and

(4) Whether new or modified IOU shareholder responsibility for portfolio mismanagement should be implemented.

After more than 10 months of dedicated work on the complex issues associated with portfolio optimization, the WG 3 Co-Chairs are pleased to file this Final Report to present the areas of consensus reached among the Co-Chairs. As discussed herein, the Co-Chairs' consensus proposals resolve a majority of the Phase 2 Scoping Memo's issues for WG 3. While the Co-Chairs' consensus proposals do not necessarily have the support of every party participating in WG 3, the Co-Chairs' consensus proposals represent thoughtful, reasonable and workable compromises among the Co-Chairs who, as Community Choice Aggregators ("CCA"), an Electric Service Provider ("ESP"), and an IOU, reflect the interests of a broad spectrum of the stakeholders in WG 3. The Co-Chairs jointly urge the California Public Utilities Commission ("CPUC" or "Commission") to adopt their consensus proposals and the implementation steps required to realize the Co-Chairs' consensus proposals, as set forth herein.

This Final Report also identifies areas of non-consensus among the Co-Chairs. The Final Report does not seek to advance the position of any party other than the Co-Chairs' consensus proposals. Parties' prior comments on proposals advanced by WG 3 in the First and Second Workshop presentations, and the Co-Chairs' response to parties' comments on the Second Workshop presentation, have been submitted with the First and Second Progress Reports of WG 3, and comments received from the Third and Fourth Workshops and in response to requests for proposals to address the Phase 2 Scoping Memo's Issues 2 through 4 are attached to this Final Report. Parties will have a further opportunity to clarify and/or advance their positions on matters within the scope of WG 3 in opening and reply comments on this Final Report.

A. Co-Chair Consensus Proposals for Adoption by the Commission

The Co-Chairs respectfully submit for approval by the Commission the following "Consensus Proposals." These proposals are discussed in further detail in subsequent sections of this report.

1. Adopt the following allocation and market offer-based frameworks for disposition of the IOUs' PCIA-eligible products. The approach considers four products – Local Resource Adequacy ("RA"), System and Flexible RA (or "System and Flex RA"), greenhouse gas ("GHG")-free energy, and Renewables Portfolio Standard ("RPS") energy.[2] The table below provides a high-level summary of the proposals:

Product	Framework	Description
Local RA	Allocation	• Allocation of the IOUs' PCIA-eligible Local RA portfolio to all PCIA-eligible load serving entities ("LSE")[3] based on their forecasted, vintaged, coincident peak load share (MW) • Allocations will utilize a "CAM-like" mechanism (the "PCIA Showing") in which the IOU shows capacity on behalf of other LSEs

2 While System and Flexible RA are two distinct products/attributes, they may be collectively referred to as one product within the context of this Final Report.

3 Throughout this Final Report, reference to PCIA-eligible LSEs is intended to include the IOUs.

System and Flex RA	Voluntary allocation and market offer	• PCIA-eligible LSEs will be provided an annual option to receive an allocation from the IOUs' PCIA-eligible System and Flex RA portfolios based upon each LSE's forecasted, vintaged, coincident peak load share (MW) • Declined allocations will be offered by the IOUs to the market twice annually through a competitive solicitation process (the "Market Offer") • System and Flex RA will utilize the PCIA Showing mechanism for allocations
GHG-Free Energy	Voluntary allocation	• PCIA-eligible LSEs will be provided an annual option to receive an allocation of GHG-free energy from the IOUs' PCIA-eligible large hydroelectric and/or nuclear portfolios based upon each LSE's forecasted, vintaged, annual load share (MWh) • Declined allocations will be reallocated among the PCIA-eligible LSEs that accepted allocations in accordance with their forecasted, vintaged, annual load shares
Renewables Portfolio Standard Energy	Voluntary allocation and market offer	• PCIA-eligible LSEs will be provided an annual option to receive an allocation from the IOUs' PCIA-eligible RPS energy portfolios based upon each LSE's forecasted, vintaged, annual load share (MWh)

		• To receive long-term contracting benefits from allocations, however, an LSE must elect to take its allocations through the remaining life of the longest contract in their PCIA vintage, which must last at least 10 years from the allocation start date[4] • Declined allocations will be offered for sale by the IOUs through a Market Offer process. IOUs will make a portion of declined allocations available through long-term sales contracts, as described in more detail in this report

The WG 3 discussion on these approaches was robust and shared broadly at the workshops, and with the Co-Chairs' respective stakeholders. Feedback and input from commenting parties helped shape this final proposal. All customers (bundled and unbundled) equitably benefit by receiving the products or the value of those products already purchased on their behalf by the IOUs, and LSEs have the flexibility and autonomy to manage the composition of their own portfolios by choosing whether to accept or decline a portion of their allocations. The details of this Consensus Proposal on Issue 1 of the Phase 2 Scoping Memo are discussed in Section V herein.

2. Adopt updates to the PCIA ratemaking mechanism to be implemented in conjunction with above described mechanisms, as described in Section V.H herein:
    a. Apply a $0/kW-month ("kW-mo") Market Price Benchmark ("MPB") to the Local RA attributes. A one-time exclusion from the PCIA rate cap shall be permitted to accommodate the additional costs associated with the implementation of the Local RA allocation.
    b. Treat System and Flex RA and RPS energy allocations like sales to the LSE receiving the allocation, priced at the applicable year's attribute MPB value

4 A grandfathering provision will apply in the first election opportunity to grant vintages that lack contracts with at least ten years remaining a one-time opportunity for long-term treatment if certain criteria are met. See Section V.D.2.b.

according to the forecast and true-up mechanisms contemplated by D.19-10-001, with revenues offsetting costs in the Portfolio Allocation Balancing Account ("PABA") according to the existing PCIA framework's treatment of sales.

c. Allocate all sales revenues from the Market Offer process across the PABA vintaged sub-accounts in proportion to the allocation volumes declined in each vintage.

d. Re-allocate any unsold System and Flex RA and RPS energy on a forecasted, vintaged, peak- and annual-load share basis, respectively, to all LSEs at $0. Such re-allocated attribute volumes shall be treated as sales at $0 and incorporated into the relevant MPB by the CPUC's Energy Division ("ED") as any other reported sales transaction would be, as contemplated by D.19-10-001.

e. During the transition period prior to full implementation of the RPS energy Voluntary Allocation and Market Offer ("VAMO") proposal, only RPS generation, excluding banked RECs, that (i) is offered for sale by the IOU, (ii) remains unsold, and (iii) is in excess of the IOU's interpolated annual RPS compliance target is to be valued at $0/MWh.

3. Direct the IOUs to issue a Request for Interest ("RFI") in 2021 and 2022 to solicit interest from their RPS counterparties in pursuing agreements to optimize the PCIA portfolios. The RFI will solicit interest from IOU counterparties to potentially contract with other LSEs for buy-outs or full assignments of the IOU's RPS contracts that would remove the contracts from the IOU's portfolio. The IOUs will connect interested counterparties with LSEs, who will be free to engage in negotiations. Any final agreement between the counterparty and other LSE will be subject to agreement by and among the counterparty and IOU, and approval of the Commission for IOU cost recovery purposes.

   The RFI will, coincident with the request for potential contract assignments, solicit offers from contract counterparties for proposed terminations, buy-outs, or amendments that may result in net cost savings or added value for customers. The IOUs will evaluate counterparties' proposals and will seek to negotiate agreements to amend or terminate the counterparty's contract, if doing so is deemed by the IOU to be in the best interest of all customers. The IOUs will include any successful agreements in their annual Energy Resource Recovery Account ("ERRA") Review of Operations application filings or through an advice letter or other application, as appropriate, for Commission review and approval. The details of this Consensus Proposal on the Phase 2 Scoping Memo's Issue 2 are discussed in Section VI herein.

4. Direct each IOU to report on its implementation and outcomes of the new RFI processes in an appropriate venue (to be determined) as proposed in Section VI.B.2.e., including identifying all rejected offers and the basis for not moving forward in negotiations or any ultimately unsuccessful outcome. Additionally, the IOUs will report or continue to report in their annual ERRA Review of Operations applications, as applicable: (1) material events of defaults, any termination rights associated with such material events of default, and any actions taken with respect thereto; and (2) cost savings received from active portfolio management.
5. Address issues associated with the implementation of the above proposals within relevant Commission proceedings (*e.g.,* Integrated Resource Planning ("IRP") Order Instituting Rulemaking ("OIR") (R.16-02-007), RPS Procurement Plans (R.18-07-003), Bundled Procurement Plans ("BPP"), and RA OIR (R.17-09-020), as required). BPP and RPS Procurement Plan updates will conform to the WG 3 Final Decision establishing the allocation, Market Offer, and RFI processes. The Co-Chairs propose that the Commission issue a decision in Track 4 of the RA OIR by June 2021 ruling upon the modifications needed to the RA process and timelines, establishment of the PCIA Showing mechanism, and establishment of methodologies for LSEs to submit and the CPUC and/or California Energy Commission ("CEC") to calibrate vintaged annual- (MWh) and peak- (MW) load forecasts. In addition, the Commission may

need to engage the California Independent System Operator ("CAISO") and CEC to update processes, procedures, rules, and requirements to the extent necessary. Finally, each IOU shall be given sufficient time to update its BPP and RPS Procurement Plan to incorporate the Consensus Proposals, as required, and sufficient time should be provided for the Commission to approve modifications for implementation of the Co-Chairs' proposals.

6. Subject to timely completion of the implementation of the WG 3 proposals in the regulatory venues contemplated in Item 5, above, the Co-Chairs propose that full implementation of the allocation proposals take place in 2022 for 2023 deliveries of RPS energy, GHG-free energy, and System and Flex RA, and 2022 for the 2024-25 compliance years for Local RA.
7. The Co-Chairs propose that an interim approach to voluntary GHG-free energy allocations be implemented at the earliest possible date following the WG 3 Final Decision for deliveries starting in 2021.
8. The Co-Chairs recognize the broad authority of the Commission over IOU activities, and, other than as provided in Consensus Proposal 4, above, do not recommend that any new or modified standards for IOU shareholder responsibility for portfolio mismanagement are required at this time.

The Co-Chairs submit that their Consensus Proposals represent reasonable, thoughtful and workable compromises across a broad spectrum of the stakeholder interests in WG 3 and should be adopted by the Commission. The Consensus Proposals resolve all issues in WG 3 except for the Non-Consensus Items, discussed below.

B. <u>Non-Consensus Items Requiring Resolution by the Commission in its Final WG 3 Decisions</u>

Despite best intentions and thorough discussions, the Co-Chairs were unable to reach consensus on the following issues (the "Non-Consensus Items"), which are described in more details in the referenced sections of this Final Report. The Co-Chairs anticipate that each may file separate comments in support of their positions below.

1. Should there be a Market Offer process for Local RA?[5]
    a. SCE and CalCCA propose that all parties will be provided an allocation which may not be declined, and there will be no Market Offer of Local RA.
    b. Commercial proposes that Local RA be subject to a voluntary allocation followed by a Market Offer, similar to the System and Flex RA proposal.
2. What are the appropriate steps and timelines for interim allocation and Market Offer processes to take effect?[6]
    a. SCE proposes that interim RPS energy voluntary allocations be implemented in 2021 for 2022 deliveries on the basis of the LSEs' actual, vintaged, annual load shares, but without a Market Offer process. To the extent that implementation of such RPS energy allocations would jeopardize the IOUs' abilities to meet their RPS compliance requirements, cause undue cost increases, or cause cost shifts to bundled service customers, the IOUs may petition the Commission to delay interim implementation. SCE opposes an interim implementation of RA allocations prior to full implementation in 2022 for 2023 for System and Flex RA and for 2024-25 for Local RA.
    b. CalCCA and Commercial support an interim implementation of the RPS energy voluntary allocation at the earliest possible date following the WG 3 Final Decision, for deliveries beginning in 2021. An interim implementation of the RA frameworks is proposed to commence in 2021, pending the WG 3 Final Decision, for System and Flex RA voluntary allocations for the 2022 compliance year and Local RA allocations for the 2023 and 2024 compliance years.

[5] See Sections V.B.2.b and V.B.4.

[6] See Section VII.B.

3. Should payments made by the IOU pursuant to certain Commission-approved contract buy-outs, assignments, terminations or other optimization activities be excluded from the PCIA rate cap adopted in D.18-10-019?[7]
    a. SCE and Commercial support a process that allows the IOUs to submit an advice letter to request exclusion of specific portfolio optimization payments that may require up-front payments but result in savings to customers in subsequent years.
    b. CalCCA opposes a carve-out from the PCIA rate cap of any additional costs associated with Commission-approved RPS contract buy-outs, assignments, terminations or other optimization agreements.
4. To what extent can the IOUs be subject to disallowance risk based on actions not taken in response to the RFI, as submitted in a report on the RFI process? How often should the report be filed, when, and in what venue?[8]

    The Co-Chairs were unable to reach consensus on the timing, frequency, and venue for the RFI report, and extent to which the IOUs are subject to disallowances by the Commission based on actions not taken within the RFI process.

Positions on the Non-Consensus Items are set forth in more detail in the referenced sections of this Final Report. Each Co-Chair, along with other parties to this proceeding, will have the opportunity to submit individual opening and reply comments advancing its positions on these Non-Consensus Items. The Co-Chairs request that the Commission resolve each of these Non-Consensus Items in its final decision addressing the WG 3 issues.

III.
BACKGROUND

On October 11, 2018, the Commission issued D.18-10-019 modifying the PCIA methodology and opening a second phase of this proceeding to enable parties to further develop

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[7] See Section VI.B.2.d.

[8] See Section VIII.C.

proposals for portfolio optimization and cost reduction for future consideration by the Commission.[9] On February 1, 2019, the Commission issued the Phase 2 Scoping Memo, directing parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission.

Due to the complexity and number of issues to be resolved in WG 3, the Phase 2 Scoping Memo anticipated a final report on consensus and non-consensus issues by January 30, 2020, with a proposed decision to be issued by second quarter 2020. The schedule was permitted to be further modified by assigned Commissioner or Administrative Law Judge ("ALJ") as required to promote the efficient and fair resolution of the issues scoped in the proceeding. The Co-Chairs requested an extension to file the Final Report to February 21, 2020 due to the breadth of the WG 3 scope.[10] This request was approved by the ALJ on January 22, 2020 and moves the expected date for a Proposed Decision to third quarter ("Q3") 2020.[11] This report satisfies the requirement of a final report on WG 3's activities, as described in the Phase 2 Scoping Memo.

A. <u>WG 3 Co-Chair Responsibilities</u>

As directed in the Phase 2 Scoping Memo, the Co-Chairs of WG 3 are responsible for the following tasks:

1. Scheduling the Working Group's meetings, and associated logistics;
2. Addressing each of the Commission-directed topics and schedule;
3. Holding Workshops; and
4. Preparing and filing periodic reports according to the schedule for WG 3.

B. <u>Procurement Guide</u>

The Phase 2 Scoping Memo recognized that the Working Groups would be more efficient if all participants were provided with a common reference guide on how the IOUs' portfolios have developed over time and in compliance with statutory and Commission requirements.

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9 D.18-10-019, p. 97.

10 Email Request of WG 3 Co-Chairs for Additional Changes to Remaining Schedule, Jan. 17, 2020.

11 Administrative Law Judge's Ruling Modifying Proceeding Schedule, Jan. 22, 2020 at 2.

Pursuant to the Phase 2 Scoping Memo, the IOUs hosted a meet-and-confer session via conference call to develop an outline for the Procurement Process Reference Guide ("Guide"). All parties were invited to participate. The IOUs incorporated participants' input into a final outline, which was served on March 11, 2019. The IOUs used the final outline to produce the Guide, a draft of which was provided to CPUC staff for review on April 4, 2019. The final Guide was sent to the service list on April 25, 2019.

IV.

PROCESS FOR WG 3

A. Principles for WG 3 Work

The Co-Chairs agreed that the following principles should govern the work of WG 3:

- Work collaboratively in good faith toward practical and commercially viable solutions for the benefit of all customers.
- Be consistent with California statutes, CPUC decisions, energy policy goals and mandates.[12]
- Respect the terms of existing Power Purchase Agreements ("PPAs") between power suppliers and IOUs.[13]
- Allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law.[14]

B. Regular Meetings of WG 3 Co-Chairs

Beginning on March 27, 2019, the WG 3 Co-Chairs met once a week, usually by conference call but also in person, as needed. Over the past 3 to 4 months, the Co-Chairs have met two times per week, as needed to review details and reach agreement. The weekly call among the Co-Chairs was held on Wednesday afternoons for approximately 2.5 hours, with the second weekly meetings taking place on Friday afternoons for approximately 2 hours. The

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[12] Phase 1 Scoping Memo, 1.e.

[13] Phase 1 Scoping Memo, 1.k.

[14] Phase 1 Scoping Memo, 1.f.

purpose of these calls was to gain consensus, share concepts and proposals, identify areas of alignment and non-alignment, and define subsequent action items. To facilitate active participation, presentations and written proposals were developed and circulated in advance of these calls to allow the Co-Chairs to review the material internally and with their constituents prior to the weekly meetings. The Co-Chairs met in person, generally prior to the workshops, to focus attention on finalizing consensus and non-consensus proposals and compiling the workshop presentations. The meetings have been active, collaborative in nature, and well-attended by the representatives and constituents of the Co-Chairs.

C. Working Group 3 Workshops

As required by the Phase 2 Scoping Memo, the Co-Chairs held four workshops to which all stakeholders and intervenors to the proceeding were invited. A notice was sent to the service list indicating the location, date, and time of each workshop. In advance of each of these workshops, the Co-Chairs disseminated presentation materials. Additionally, options were provided for both in-person and WebEx or Skype attendance, to ensure inclusion of all parties. Parties were encouraged to ask questions or make comments throughout the presentations. There was robust engagement by the audience and those participating by WebEx or Skype, at each of the workshops. A more detailed description of the content covered in each workshop is attached in Appendix F.

Following each workshop, parties were invited to provide informal comments. The feedback received was helpful in that it provided the Co-Chairs with a better perspective on the various stakeholders' positions, concerns, and alternative proposals. The presentations and informal comments received from the participants in the first two workshops were attached to the Co-Chairs' First and Second Progress Reports. The presentations and parties' informal comments on the Third and Fourth Workshops, and on proposals for Issues 2 to 4, are attached hereto in Appendices A to E.

D. Working Group 3 External Stakeholder Engagement

In addition to the public engagement with stakeholders participating in the formal workshops, the Co-Chairs established a SharePoint site, managed by SCE, to provide a single repository of the workshop materials, informal comments, and the Co-Chairs' meeting agendas and work plan for the WG 3 project. The Co-Chairs also submitted their own reply comments to the service list in response to informal comments from the Second Workshop. Additionally, the Co-Chairs engaged in a number of conversations with third parties outside of the immediate participants in the Working Group process. More information on the WG 3 external engagement is provided in Appendix F.

V.

SCOPING ISSUE 1: STRUCTURES, PROCESSES, AND RULES GOVERNING PORTFOLIO OPTIMIZATION

A. Introduction to Proposal

1. Background

The Co-Chairs explored several frameworks for optimizing the IOUs' existing portfolios and attributing portfolio resources to those customers paying for them. Two main conceptual approaches were considered: (i) an excess sales approach in which the IOUs offer attributes in excess of bundled service customers' compliance requirements to the market; and (ii) an allocation-based approach that allocates attributes from the IOUs' respective PCIA-eligible portfolios to all LSEs serving customers paying the PCIA. Within the second alternative, the Co-Chairs examined several allocation and sales mechanisms, including mandatory allocations, voluntary allocations, and a combination of allocations and sales or "market offers."

2. Excess Sales Concept

The Co-Chairs began by exploring an "Excess Sales" concept wherein the IOU would retain the portion of its procured resource attributes needed to serve its bundled service compliance requirements and would offer attributes in excess of such needs for sale to the market.

With respect to RA specifically, the Co-Chairs were challenged in finding alignment in three primary areas centering on the definition of "excess," as follows:

- Methodology for determining the amount of RA capacity retained by the IOU in excess of its compliance requirement ("Buffer"). IOUs have historically reserved some additional capacity to account for foreseeable regulatory requirements (*e.g.,* to meet outage substitution requirements) and unforeseen deficiencies (*e.g.,* Net Qualifying Capacity ("NQC") reductions, contract defaults, operational constraints (such as those based on hydrological conditions), etc.);
- Timing for making excess RA available to the market relative to establishment of final RA requirements, the year-ahead showing, and the month-ahead showings;
- Treatment of capacity not shown in supply plans to account for known operational constraints, reduced water levels, outages, maintenance, permitting, or other constraints.

Although these areas of non-consensus arose in the context of RA specifically, the challenges encountered in establishing the "excess" amount were expected to also arise in addressing sales of excess RPS energy.

3. Allocation Concepts

The discussions on allocations focused on developing frameworks by which LSEs of customers who had departed bundled service could receive their customers' share of the PCIA-eligible attributes procured on their behalf when they were bundled service customers. Each PCIA-eligible LSE's allocations are based upon a proportional share of the IOU's entire PCIA-eligible, vintaged position. The allocation methodologies were viewed positively by the Co-Chairs because they avoid concerns about how to define excess attributes and therefore prevent disputes regarding the volume of attributes an IOU is required to make available to the market. Additionally, allocations ensure that all attributes are appropriately distributed among all LSEs, so their customers are able to realize the value they are paying for.

Initially, allocation discussions focused on Local RA and GHG-free energy. CalCCA proposed an allocation of all Local RA to LSEs in proportion to their peak load contribution to ensure capacity in tight local areas is distributed fairly among the LSEs. The Co-Chairs also discussed a concept for a voluntary allocation of GHG-free energy where LSEs would receive their share of attributes and be allowed to reflect the energy on their Power Content Labels ("PCL"), subject to the CEC's rules. The Co-Chairs agreed that this approach was an equitable method of distributing attributes for those Local RA and GHG-free resources procured on all customers' behalf. After initial success with Local RA and GHG-free energy, the Co-Chairs considered additional allocation-based approaches for System and Flex RA and RPS energy.

4. Voluntary Allocation and Market Offer Concept

In Phase 1 of R.17-06-026, Commercial developed its Voluntary Allocation and Auction Clearinghouse ("VAAC") proposal under which the IOUs would annually offer a voluntary allocation of their excess PCIA-eligible resources and then auction off any unallocated attributes. The VAAC proposal formed the basis for the Co-Chairs' Voluntary Allocation and Market Offer ("VAMO") proposal for RPS energy and System and Flex RA attributes within the IOUs' PCIA-eligible portfolios. Under the VAMO framework, PCIA-eligible LSEs would be provided a voluntary allocation of PCIA-eligible products, with any unallocated products being sold through an annual "Market Offer" process.

The Co-Chairs have reached alignment on most major issues regarding the methods for treating each product. The Co-Chairs' proposals regarding each of the four products are outlined below.

B. Resource Adequacy

1. Background on Resource Adequacy

System RA is designed to ensure that there is enough generating capacity on a year-ahead basis to meet monthly peak load requirements, while Local RA is designed to address capacity requirements on a multi-year basis within specific CAISO transmission constrained areas. System RA requirements are determined based on each LSE's CEC-adjusted, coincident peak load forecast for each month plus a 15 percent planning reserve margin. RA procured from local resources can simultaneously be used to meet both Local, System, and Flexible RA obligations. Flexible RA is designed to ensure that sufficient dispatchable energy exists within the CAISO system to meet the ramping needs resulting from increased renewable penetration in California. Flexible RA requirements are based on an annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably.[15]

The CAISO evaluates each resource's NQC to identify its ability to contribute to meeting peak capacity needs. For System RA and the CAISO's evaluation of Transmission Access Charge ("TAC")-area Local RA requirements, the resource's NQC in each month is used to determine its contribution to that month's RA requirements. However, in the CPUC's evaluation of a resource's contribution to meeting an LSE's Local RA showing requirement, only the August NQC value is used for each showing month of the year.[16] A resource's contribution to meeting Flexible RA is determined by the resource's Effective Flexible Capacity ("EFC") for each month in the year, as determined by the CAISO. The CAISO typically publishes the final NQC and EFC for resources in late September.

As part of the RA process, LSEs submit their historical loads in March and forecasted loads for the next compliance year in April to the CPUC and CEC for calibration and identification of the coincident peak load shares.[17] Based upon these calibrated forecasts, the ED publishes LSEs' initial RA requirements, including their preliminary allocation share of Cost Allocation Mechanism ("CAM") and demand response ("DR") capacity, in July, and the final RA requirements and CAM share in late September.[18] LSEs' year-ahead compliance filings are

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[15] CPUC 2020 RA Guide at 19.

[16] *Id.*

[17] CPUC 2020 RA Guide at 7.

[18] *Id.*

due to the CAISO and the CPUC on October 31 of each year for the forthcoming compliance year(s).[19]

Within the year-ahead RA filing, LSEs must meet 90 percent of their year-ahead requirement for System RA (for May to September) and Flexible RA (for all 12 months) and 100 percent of their multi-year Local RA requirement for the first and second compliance years and 50 percent of their multi-year Local RA requirement for the third compliance year.[20] LSEs are required to meet 100 percent of their Local, System, and Flexible RA requirements in the monthly compliance filing, which is due 45 calendar days prior to the showing month.

The current RA process includes a monthly and quarterly load forecast filing by LSEs. The monthly load forecast filing provides the needed information to the Commission to adjust an LSE's System RA requirements to account for intra-year load migration, while the quarterly load forecast filing provides the needed information to adjust an LSE's CAM and Reliability Must Run allocations.

Discussions are currently progressing in the RA OIR about the need and potential role for a Central Procurement Entity ("CPE") for Local RA procurement. Additionally, the CAISO's RA Enhancements Initiative is contemplating, among other things, how to appropriately value the capacity contribution pursuant to an Unforced Capacity availability ("UCAP") methodology, including for use-limited resources.[21] The Co-Chairs' proposal does not consider the potential impact of the establishment of such a CPE or UCAP methodology. However, to the extent that these changes or any other regulatory changes occur, the proposed allocation methodologies should be adapted to incorporate the impact of these regulatory requirements and processes.

2. <u>Co-Chair Consensus Proposals</u>

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[19] *Id.*

[20] *Id.* at 4.

[21] Use-limited resources are resources that are subject to de-rates due to limitations upon their ability to operate to their maximum capacity output (NQC), maximum run times, or frequency of use, etc. as a result of issues such as insufficient fuel, air permit restrictions, charging restrictions, or other constraints.

a) Overview of RA Allocations

The Co-Chairs propose that the determination of LSEs' RA allocations will be calculated on the basis of each LSE's forecasted, vintaged, coincident peak-load share as informed by the year-ahead RA procurement obligations within the RA process, in a similar manner to CAM. The PCIA-eligible, vintaged RA positions to be allocated will be set in the IOUs' July CAM filings to the Commission, as updated for NQC and EFC adjustments by CAISO. Prior to this deadline, the IOUs may sell, swap, trade, or otherwise dispose of their Local, System, and/or Flexible RA attributes for portfolio optimization purposes, and only the residual volumes would be subject to allocation. Any change in Local, System, and/or Flexible RA positions due to non-resource specific portfolio optimization will be shared proportionally from each vintage. Any portfolio optimization activity pertaining to a specific resource, such as an amendment, termination, or assignment, will affect the costs and attribute positions within the resource's vintage only. The allocations will be conveyed through a mechanism structured similarly to CAM, however, they will be on a vintaged basis, known herein as the "PCIA Showing."

b) Overview of Local RA Allocation

The Co-Chairs propose that the IOUs' PCIA-eligible Local RA positions be subject to an annual allocation among all PCIA-eligible LSEs for the multi-year Local RA compliance showing. As with Local RA obligations, allocated Local RA volumes for years 2 and 3 will be based upon the forecasted, vintaged, annual[22] peak-load (MW) share for the first year for which showings are required (the "prompt year") only (rather than the forecasted peak-load shares in years 2 and 3), and will thus only be indicative and will be updated in the following year on the basis of updated load shares and RA positions. Only Local RA capacity from within the IOU's TAC area will be subject to this Local RA allocation. All non-TAC area, PCIA-eligible Local RA capacity held by the IOU for system and/or flex RA purposes will be treated as System and Flex RA for PCIA allocation purposes. The IOUs may continue to perform portfolio

[22] Historically this has been the August peak, but more recently September peak.

optimization activities to maximize the value of the non-TAC area Local RA attribute. Any System and Flex RA attributes associated with an IOU's local resources within that IOU's TAC area will also be allocated as Local RA. SCE and CalCCA propose that LSEs may not decline their Local RA allocation and there will be no Market Offer process for Local RA. Commercial supports a voluntary allocation of Local RA followed by a Market Offer of any unallocated Local RA.

c) Overview of System and Flex RA VAMO

The Co-Chairs propose that System and Flex RA be made available annually to PCIA-eligible LSEs through a voluntary allocation that will offer two election opportunities, in the spring and in the fall, in the year prior to the compliance year. In the spring election, PCIA-eligible LSEs may elect to decline up to 50 percent (in 10 percent increments) of their eligible allocation share, which would then be offered for sale in the spring Market Offer process. In the fall, PCIA-eligible LSEs will make a final election to take a constant percentage (in 10 percent increments) of their forecasted, vintaged, monthly, peak-load share as an allocation for the compliance year, which will be multiplied by each month's PCIA-eligible, vintaged RA position, to determine that LSE's allocation quantities for each month. The System and Flex RA allocations that are declined by LSEs will be made available for sale by the IOU through a Market Offer process occurring twice annually, in the spring and fall in the year prior to the compliance year. In alignment with current protocols for all solicitations, an Independent Evaluator ("IE") will participate in the Market Offer process.

d) PCIA Showing

The Co-Chairs propose a "PCIA Showing" for the distribution of the IOUs' PCIA-eligible RA capacity, which will function in a similar fashion as CAM, except on a vintaged basis. In this proposed PCIA Showing, the IOU is transferred a portion of the peak-load from other LSEs and must show the RA capacity from the PCIA-eligible resource or a substitute resource to serve that portion of the PCIA-eligible LSE's load. Each PCIA-eligible LSE's RA obligation will be reduced based upon their allocation or Market Offer purchase, and the IOU will show the PCIA-eligible resources' RA capacity, or substitute capacity, on behalf of itself and the corresponding LSEs in the IOU's RA compliance showing. As described in Section V.F, the Co-Chairs propose that ED determine the forecasted, vintaged, monthly, coincident peak-load shares and capacity allocated to each LSE within the PCIA Showing. A process will need to be developed within the RA OIR to calibrate LSEs' vintaged, coincident peak-load shares, similar to that process currently performed by the CEC for determining coincident peak demand. Each LSE would then report its PCIA-eligible RA capacity credit, or in the case of the IOUs, the PCIA-eligible RA capacity debit, on its year-ahead and month-ahead RA filings with the CPUC and CAISO. The allocated and sold RA positions, resulting from the VAMO proposal, will be finalized in the PCIA Showing for the compliance year by the October 31 year-ahead RA compliance filing.

e) System RA and Flex RA Market Offer Process

The Co-Chairs propose that the IOUs offer to the market any declined allocation of System and Flex RA through a competitive solicitation ("Market Offer") process. Because RA compliance is subject to predefined requirements and compliance filing deadlines, the Co-Chairs propose that the System and Flex RA Market Offer will be conducted twice annually, in the spring[23] and the fall[24], for deliveries in the prompt year.

The Co-Chairs propose that System and Flex RA Market Offer contracts will have terms ranging from one calendar month to one calendar year in length. The sales will be structured as shares of the PCIA Showing, rather than as typical RA tags. This may require that the IOUs develop new sales contracts, but each IOU may determine the appropriate form for its purposes. Offers will be valued on the basis of revenue maximization until all volumes are sold. Revenues will flow through the PABA as a credit against the PCIA costs, and will be allocated to the vintaged PABA sub-accounts on the basis of the vintages from which the RA volumes available

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[23] See Section V.B.2.e.1.

[24] See Section V.B.2.e.2.

for sale were sourced.[25] Buyers may be required to provide appropriate credit, collateral, netting agreement terms, or other commercial arrangements to protect all customers from defaults, which could otherwise lead to higher PCIA rates.

The Market Offer process for System and Flex RA will be conducted using Commission pre-approved mechanisms for solicitation administration, valuation, selection, and contracting, which will be proposed by the IOUs within their BPPs or an advice letter requesting Commission approval to launch the Market Offer. Additionally, the Market Offer processes will be monitored by an IE, and the CAM review group will be consulted on offer selections. The Market Offer process will be open to all market participants, including the IOU holding the Market Offer process, but to participate the hosting IOU may be required to (i) submit bids to the IE and ED in advance of the Market Offer's launch or (ii) establish dual procurement teams separated by an ethical wall, with monitoring by the IE.

(1) Spring System and Flex RA Voluntary Allocation and Market Offer Process

The Co-Chairs propose that PCIA-eligible LSEs will have an opportunity in April prior to the compliance year to decline a portion of their anticipated annual allocation. By mid-April, the PCIA-eligible LSEs will have calculated their year-ahead load forecasts for the RA process, and the IOUs will have filed their indicative PCIA-eligible, vintaged RA positions. This information gives PCIA-eligible LSEs an estimate of their eligible allocation amounts for planning purposes.

In the spring election, each LSE may choose to either defer their decision to the fall election period or may make a binding decision to decline up to 50 percent of their allocation (in 10 percent increments). The declined volumes to be made available for sale in the spring Market Offer process will be calculated according to the previous year's forecasted, coincident, peak-

25 For an example of how the valuation is proposed to work and revenues are to be allocated, refer to Appendix H on Table 46 and Table 52, respectively.

load shares and the current vintaged, PCIA-eligible RA position. Any unsold quantities in the spring Market Offer will be offered for sale in the fall Market Offer.

Parties bidding into the spring Market Offer will bid for firm quantities of System and Flex RA within the PCIA Showing. However, LSEs' final allocation shares will not be known until late September, pending the final publication of the (i) LSEs' forecasted, vintaged, monthly, coincident peak-load shares, (ii) IOUs' PCIA-eligible RA positions, and (iii) resources' final NQC or EFC values. Therefore, LSEs who elect to decline a portion of their allocations in the April election opportunity bear the risk that final allocation volumes may result in less capacity being available to them in the fall VAMO process.

(2) Fall System and Flex Market Offer Process

Under the existing RA process, the fall allocation elections will be submitted following the CPUC's publication of the final RA procurement requirements and the final PCIA allocation shares in late-September, and the final RA year-ahead showing is due on October 31. This leaves a tight window to conduct the IOUs' fall Market Offer process in which all declined allocation volumes, including any unsold attributes from the spring Market Offer, will be offered for sale. This timing issue is exacerbated as LSEs, including the IOUs, may need to continue performing incremental RA procurement following the completion of the IOUs' fall Market Offer processes to meet their year-ahead compliance requirements. The fall Market Offer process should be completed as soon as practical to provide enough time for the Commission to finalize the PCIA Showing credits and debits, allow LSEs to conduct any incremental procurement, and allow LSEs to prepare their year-ahead RA showings. This is an aggressive and tight timeline for conducting all of the requirements implied by the Market Offer and subsequent incremental procurement. Additionally, there must be sufficient time provided following the Market Offer processes to incorporate the sales prices and volumes into the Update to ERRA Forecast applications, due in early November of each year. Thus, the Co-Chairs propose that the Commission order that Track 4 of the RA OIR revise the existing RA process timelines to move them forward in the year, to take into account the additional steps required of

LSEs and the regulatory agencies, including the CPUC, CEC, and CAISO, by the System and Flex RA VAMO process with a final decision by June 2021.

(3) Unsold System and Flex RA

The Co-Chairs propose that any unallocated System and Flex RA that remains unsold in the fall Market Offer should be subsequently allocated at no cost and pro-rata among all LSEs on the basis of LSEs' forecasted, vintaged, peak-load shares. These re-allocations will be reported by the IOUs to ED and should be included in the System or Flex RA MPBs as if they are RA sales transactions at $0/kW-mo, reflecting the specific quantities unsold. An example of how the re-allocation is performed is included in Appendix H in Tables 49 and 50.

f) Intra-Year Load Migration

While the CAM mechanism has processes for addressing intra-year load migration, and thus allows for re-allocation of CAM capacity on a quarterly basis, the Co-Chairs propose not to permit intra-year load migration adjustments to the allocated PCIA-eligible RA volumes. However, if a new LSE has filed with the Commission to form midway through the compliance year and has a year-ahead RA showing obligation, that LSE would be eligible for its RA allocations from the start of its RA obligation period. The Co-Chairs propose that a report be published by ED to evaluate whether such a re-allocation for load migration should be incorporated into the mechanism after it has been in effect for two years.

g) Substitution for Unavailable RA

Under the current CAISO Tariff, the IOUs, as the scheduling coordinator for the PCIA-eligible resources, as applicable, are responsible for providing substitution capacity for shown capacity that is on a planned or forced outage.[26] If substitution capacity is not provided, the CAISO may exercise its authority and disapprove the planned outage or cancel the previously approved planned outage or assess Resource Adequacy Availability Incentive Mechanism

[26] CAISO Tariff, Sept. 28, 2019, at 203.

("RAAIM") penalties.[27] Under the Co-Chairs' proposal, the IOUs are constrained from reserving capacity from the PCIA-eligible portfolio to mitigate foreseen and unforeseen portfolio risks associated with the PCIA-eligible resources, such as planned outages (but not use-limited resources, which may be de-rated). Accordingly, the Co-Chairs recognize that the PCIA-eligible RA costs may increase as the IOU may need to procure additional capacity for substitution in the Delivery Year[28] to manage the PCIA portfolio on behalf of all customers. As with CAM, the Co-Chairs propose that the IOUs recover the costs associated with procuring or attempting to procure substitution capacity through rates. In this case, the Co-Chairs propose to allocate the costs of substitution capacity or other RA capacity required to manage the PCIA-eligible portfolio in compliance with CPUC and CAISO regulations through the PABA according to the vintaged sub-account to which the resource requiring substitution capacity belongs. The Co-Chairs propose the same general cost recovery rules as in the CAM[29], with minor adjustments:

1. To the extent the IOU has excess RA in its bundled position, the IOU may transfer such excess RA to the PCIA Showing and charge the PABA vintage subaccount for the relevant resource at the relevant MPB.[30]
2. If the IOU procures substitution capacity in the market, the actual capacity price paid shall be charged to the resource's PABA vintage sub-account for cost recovery.
3. If the IOU is unable to procure substitution capacity and incurs CAISO capacity procurement mechanism ("CPM") charges, RAAIM penalties, any costs

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27 *Id.* at 205.

28 "Delivery Year" means the immediate year to which the allocation elections pertain, or as the context requires, the current year in which deliveries of attributes shall be made to realize the allocation elections

29 CPUC 2020 RA Guide at 24.

30 For Local RA, it is assumed that ED will continue to publish the Local RA MPBs based upon market transactions, despite $0/kW-mo value being ascribed to Local RA in the PCIA. If this is not the case, then an alternative method should be developed to appropriately compensate IOUs for substitution of Local RA resources.

associated with cancelling and/or moving the outage, and/or other related costs, charges, or penalties, then such costs, charges, or penalties shall be charged to the relevant PABA vintage sub-account for appropriate cost recovery.

h) Trading of Allocated RA

The Co-Chairs propose that LSEs may enter into sales, trades, swaps, or other transaction types for the transfer or sale of their allocated share of RA in the PCIA Showing. An LSE may transact its shares any time following the allocation, and the IOU would have no further involvement in the transaction nor an obligation to report the transaction. LSEs selling their RA allocation would report a debit, and LSEs buying an RA share of the PCIA Showing would report a credit, to ED on the LSE Allocations tab of the RA template submitted at the year-ahead and month-ahead RA showings.[31]

3. Rationale for Co-Chairs' Consensus Proposals

a) Allocation of Local RA is Reasonable

The Local RA allocation proposal achieves the goal of optimizing the IOU's PCIA-eligible portfolio through the proportional allocation of products and value to all customers – bundled and departed load – that bear cost responsibility. Full allocation of PCIA-eligible Local RA is superior to an "Excess Sales" approach because it eliminates the need to address the complex issues of the size of the Buffers and uncertainty tranches and the timing of sales.

Various LSEs expressed concerns throughout the WG 3 process about the IOUs not making sufficient Local RA capacity available to the market. The proposed allocation of Local RA avoids the complexities arising from the existing constraints and potential market power issues that might exist in certain Local RA-constrained geographical areas, particularly in disaggregated local areas. Additionally, the recent expansion of the Local RA requirement to a multi-year forward requirement complicates matters when exploring the potential application of

[31] If the IOU procures a share of the PCIA Showing in the Market Offer process or through secondary trading, the IOU will receive a credit towards its compliance requirements, which will net against the debit it otherwise would realize against its RA compliance obligations for showing the PCIA-eligible RA on behalf of other PCIA-eligible LSEs.

a VAMO sales framework for Local RA. By avoiding the need to sell capacity multiple years forward, which would create complexities due to changing LSE peak-load shares and cost responsibilities, the Local RA allocation mechanism better manages potential impacts of future customer migration.

The Co-Chairs acknowledge that the Local RA allocation proposal is less flexible for LSEs. However, due to the unique conditions in the Local RA markets, as noted above, the Co-Chairs felt this was the best path forward to ensure equity and cost sharing. The proposal also addresses LSEs' desire to monetize any PCIA-eligible Local RA by making Local RA allocations tradeable in the secondary market.

b) VAMO is Reasonable

The Co-Chairs propose that the VAMO for System and Flex RA provides an equitable means by which LSEs can elect to either receive their share of PCIA-eligible System and Flex RA directly or have customers receive economic consideration through PCIA rates. The Co-Chairs chose the VAMO structure for System and Flex RA due in large part to the challenges presented by Buffers, uncertainty tranches, and sales timing encountered with the Excess Sales approach, as discussed above. Additionally, utilizing the VAMO approach is designed to help keep PCIA rates approximately where they are today, while permitting LSEs the flexibility to manage their procurement activities by choosing the volume of the IOUs' RA attributes to procure at the MPB through an allocation. The multiple sales offerings considered by the Co-Chairs will provide adequate liquidity to the market.

c) System and Flex RA Market Offer Process is Reasonable

The proposed System and Flex RA Market Offer process comports with existing IOU standards and requirements for conducting solicitations. The valuation and selection process also comports with existing mechanisms, and is reasonable for eliminating potential conflicts of interest or questions around IOUs' decision-making and judgement in administering the Market Offer process. Additionally, the use of an IE and consultation with the CAM group, provides transparency and protections for the PCIA-eligible LSEs that the IOUs are fairly and reasonably conducting the Market Offer process, and in accordance with the approved requirements and timelines.

It is reasonable to permit the IOUs (on behalf of their customers) to participate in the Market Offer process provided ethical walls or advance bid protections exist and are monitored by the IE. The IOUs' participation is expected to promote greater competition for RA capacity, and is thus expected to lead to greater value realization in the Market Offer, which will aid in reducing PCIA rates. The protections will ensure that the IOUs are not granted an advantage, as compared to other market participants, in the Market Offer process.

It is reasonable that the System and Flex RA sold in the Market Offer process is offered only for the prompt year, as the System and Flex RA compliance requirements exist only on a year-ahead and month-ahead basis. This will preserve the System and Flex RA positions for equitable allocation each year on the basis of the latest forecasts of load shares. Allowing multiple RA contract term lengths within the Market Offer, between one calendar month and one calendar year, allows maximum value to be realized for customers by permitting greater flexibility for buyers to meet their needs through submittal of offers for strips of time that comport with their specific needs.

Establishing the spring Market Offer allows LSEs to fill a portion of their RA procurement volumes well in advance of compliance deadlines, and in doing so, is expected to increase the likelihood that System and Flex RA will be sold, and may result in higher System and Flex RA revenues, which would reduce PCIA rates. It is also reasonable to re-allocate unsold RA capacity to all LSEs, as all LSEs' customers are paying the above market costs in their PCIA rates.

d) <u>PCIA Showing is Reasonable</u>

The PCIA Showing provides a simple mechanism by which IOUs can provide PCIA-eligible LSEs with their share of RA and is already proven to work by example of the CAM showing mechanism. The PCIA Showing avoids the need by the IOUs to pick and choose from which resources to allocate RA attributes to each individual PCIA-eligible LSE, as would be the case with traditional CAISO Resource ID designations. The PCIA Showing is a fair way of allocating resources, as it enables each LSE to get a share of each contracted resources' capacity, thus promoting indifference among LSEs. Aligning the PCIA Showing timeline with existing RA processes creates efficiencies and synergies by leveraging existing requirements and processes. Finally, having ED responsible for determining LSEs' forecasted, vintaged, monthly, peak-load shares and allocations of capacity should mitigate parties' concerns in the process.

The proposal to re-allocate Local RA capacity for years 2 and 3 within the calendar year following the first compliance year is reasonable. LSEs' RA obligations change year over year in response to their forecasted peak load shares, so it is only fair that their allocations change in a similar manner. Similarly, LSEs' customers' relative cost shares also change year-over-year in their PCIA rates as load migrates between LSEs, so adjusting the allocation shares annually is fair and reasonable. Finally, the amount of capacity available for allocation may change as a result of the IOUs' portfolio optimization activities or adjustments to resources' NQC and EFC by the CAISO, thus necessitating a recalculation of the amount of capacity to be distributed to each PCIA-eligible LSE.

The Co-Chairs believe that the simplification of the PCIA RA allocation process by excluding intra-year load migration adjustments appears to be reasonable, as the actual amounts of intra-year load migration are likely *de minimis* and customers will be fully compensated by the proposed ratemaking mechanisms. The Co-Chairs propose that ED review the matter and issue a report after two years of RA allocations have taken place to evaluate the impact that this simplification may have for ensuring indifference.

e) Substitution and Substitution Cost Recovery is Reasonable

Requiring the IOUs to conduct substitution or other RA procurement to comply with all CPUC and CAISO requirements associated with the PCIA Showing and to charge the PABA vintaged sub-accounts for all costs, including penalties, simplifies the PCIA Showing process for PCIA-eligible LSEs and removes the need for non-IOU LSEs to conduct their own substitution. This is a proven method, as CAM has a similar substitution requirement and follows the same general cost-recovery principles as proposed by the Co-Chairs. Cost recovery through the PCIA for portfolio management costs required to comply with CPUC and CAISO regulations, including substitution activities and costs incurred due to the inability to procure substitution and penalties or costs associated with outage cancellations, is appropriate because it maintains customer indifference and follows the current CAM process.

f) Trading of RA Allocations is Reasonable

Trades or sales of LSEs' allocated RA enables LSEs to manage and monetize their portfolios and act in the best interest of their customers. This is particularly important for Local RA, which does not implement a Market Offer process. Additionally, this option may permit LSEs to sell their share of the PCIA Showing without having to sell other procured RA positions, which may be contractually restricted from re-sales. This flexibility to sell a share of the PCIA Showing RA reduces the risk of stranding RA with an LSE who is long, in which case that PCIA-eligible RA, or the RA it is displacing in the LSE's supply plan, may be used for less valuable purposes, such as using Local RA to meet System or Flexible RA showing requirements, or simply remain unutilized. The secondary trading of RA credit may increase the complication and administrative burden, however, the Co-Chairs believe this can be implemented in a manner that minimizes impact.

4. Non-Consensus Proposals

SCE and CalCCA propose that LSEs may not decline their Local RA allocation and there will be no Market Offer process for Local RA. Commercial supports a voluntary allocation of Local RA followed by a Market Offer of any unallocated Local RA.

C. GHG-Free Energy Voluntary Allocation

1. Background on GHG-Free Energy

The Co-Chairs' proposal for GHG-free energy relates to the allocation of energy, and its associated attributes, being generated by the IOUs' PCIA-eligible, non-RPS-eligible, large hydroelectric and nuclear resources, as well as any other potential PCIA-eligible, non-RPS-eligible, GHG-free energy producing resources. The primary interest in pursuing allocations of

GHG-free energy is for showing GHG-free energy procurement on an LSE's PCL and for planning purposes in the IRP. The Commission declined to assign GHG-free energy any specific MPB "adder" in the PCIA formula, and thus GHG-free energy is treated the same as brown power in the PCIA formula, receiving credit according to the realized CAISO energy and ancillary services revenues.

2. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs propose that the IOUs will annually provide a voluntary, all-or-nothing allocation of GHG-free energy from their PCIA-eligible nuclear and/or large hydroelectric (and any other GHG-free, non-RPS, PCIA-eligible) resources to all PCIA-eligible LSEs on an annual basis. The GHG-free energy will be bifurcated into two pools: a nuclear pool and a non-nuclear pool. LSEs may make an election via a signed confirmation, serving as a sales contract, to accept or decline either or both pools in its (or their) entirety prior to the start of the flow year, in order to preserve the bundled nature of the delivered energy. No partial elections will be permitted.

The GHG-free energy allocations will be distributed on the basis of the forecasted, vintaged, annual-load (MWh) share of the PCIA-eligible LSEs, multiplied by the actual GHG-free energy production realized from the IOU's PCIA-eligible resources in each pool over the course of the flow year. LSEs who decline their allocation for either pool will have their allocation share of that pool redistributed among LSEs who accepted their allocation according to their vintaged, annual load share among the LSEs accepting that pool's allocations.

The IOU or its contracted counterparties will remain as scheduling coordinator of the resources, as applicable, and the benefiting LSEs have no rights to specify how resources are scheduled. The IOUs will continue to follow the Commission's existing least-cost dispatch requirements in their scheduling of these resources (some of which are non-dispatchable), and will provide documentation to LSEs specifying the source, volumes, and hourly profile of the GHG-free energy deliveries. LSEs accepting their allocations may claim the GHG-free energy deliveries on their PCL, subject to approval by the CEC, and may claim credit toward Clean Net

Short ("CNS") procurement requirements in IRP based on the hourly generation profile of the vintaged portfolio. As required by D.18-10-019, no incremental value will be ascribed to the GHG-free energy in the PCIA rates relative to the brown power MPB and CAISO energy and ancillary services revenue true-up.

CalCCA and Commercial propose that the PCIA-eligible LSEs that accept their allocations of GHG-free energy may trade or sell such GHG-free energy, including the right to claim the benefits on PCL. Sales contracts shall not grant any dispatch or scheduling rights to any buyers. As mandated by CEC requirements, in order to qualify for the transfer of GHG-free energy on the PCL, LSEs will need to enter into contracts establishing forward transactions.

3. Rationale for Consensus Proposal

The IOUs' GHG-free energy resources were built many years ago and were procured and/or built on behalf of all customers. These GHG-free energy resources are being paid for through the PCIA and the energy revenues are being realized by PCIA-paying customers. Therefore, the Co-Chairs believe it is only fair that these attributes be voluntarily allocated, and PCIA-paying customers benefit from the energy deliveries on their LSEs' PCLs and in IRP. Certain LSEs are prohibited from supporting nuclear energy production, so the Co-Chairs aligned upon a voluntary allocation mechanism for GHG-free energy that splits the resources into two pools: nuclear and non-nuclear, with LSEs able to elect from which (if either) pools to accept an energy allocation.

The re-allocation of unallocated GHG-free energy resources ensures an efficient distribution of clean energy across LSEs who wish to count such attributes on their PCL. The Co-Chairs believe that it does not make sense to have a Market Offer process for GHG-free energy because it is not a compliance product and does not have a market benchmark "adder" value.

D. Renewables Portfolio Standard Energy Voluntary Allocation & Market Offer

1. Background on Renewables Portfolio Standard Energy

The Renewables Portfolio Standard is California's overarching program for advancing renewable energy. The program established minimum requirements for LSEs to procure electricity from eligible renewable energy resources, certified by the CEC. LSEs must demonstrate their RPS compliance over the course of certain pre-defined three- to four-year long compliance periods that permit annual under- or over-procurement variations, provided the LSE meets its compliance period RPS procurement requirement. Senate Bill 350 requires LSEs to enter into ownership or contractual arrangements of 10 years or longer for eligible renewable resources for 65 percent of their procurement quantity requirements for all compliance periods beginning January 1, 2021.[32]

To evidence procurement of RPS generation, LSEs are required to retire Renewable Energy Credits ("RECs"), which are certified by the Western Renewable Generation Information System ("WREGIS"). LSEs are also required pursuant to RPS rules to procure RPS generation resources corresponding to certain categories, known as Portfolio Content Categories ("PCC"), which set limits on the minimum or maximum energy that LSEs may procure from specific resource types.

LSEs with an excess of RECs in a given RPS compliance period may choose to "bank" their RECs for future use. When an LSE uses this bank of RECs for its own purpose, the banked RECs retain their original PCC status and provide credit towards RPS compliance requirements, but the LSE receives no PCL credit, as the energy had already been delivered in the past. However, when an LSE sells a REC after the energy has been delivered, that REC counts only as an unbundled, PCC3 REC, and thus may lose value relative to its value if the REC holder were to use it.

2. <u>Co-Chair Consensus Proposal</u>

[32] SB 350.

a) Overview of RPS VAMO Proposal

The Co-Chairs propose that the IOUs' PCIA-eligible RPS energy be subject to an annual, voluntary allocation among all PCIA-eligible LSEs on the basis of their forecasted, vintaged, annual load (MWh) shares and the actual, vintaged, annual RPS energy production. Any unallocated RPS energy is to be made available for sale through an annual Market Offer process to be held by the IOU prior to the Delivery Year.

Regardless of allocation or sale, the IOU or its contracted counterparties, as applicable, will remain as the scheduling coordinator(s) of the RPS resources. Benefiting LSEs have no rights to specify how resources are to be scheduled, and the IOUs will continue to follow existing least-cost dispatch. Both allocations and Market Offer sales will convey rights to RECs and PCL reporting, and will be structured as forward contracts that preserve the bundled nature of the RPS energy and the PCC status from the IOU's underlying contracts. PCIA-eligible LSEs will additionally be eligible to claim their forecasted RPS energy allocations in the IRP process in proportion to the hourly generation from the IOU's vintaged RPS portfolio from which the allocations are sourced. However, only long-term allocations or sales convey rights to credit for long-term RPS procurement requirements.

b) RPS Energy Allocation Options

The Co-Chairs propose that during the annual RPS allocation election process, LSEs may elect to take a short-term allocation, a long-term allocation, or may choose to decline all or a portion of their allocation; each election to be made in 10 percent increments of the LSE's forecasted annual load share. Short term allocations will have a term of one calendar year. Long-term allocations will last through the end of the term of the longest contract in the particular PCIA vintage (excluding the term associated with utility-owned generation ("UOG") and evergreen contracts (*i.e.,* legacy Qualifying Facility contracts with contract terms that do not expire)). Once accepted, the LSE may not decline its long-term allocation election in future years, but may increase its election within future election opportunities, provided at least 10 years remain on the term of the longest-dated contract in the vintage. An LSE's long-term allocation election will be set at a fixed percentage of its forecasted, vintaged, annual load share, but both the LSE's forecasted vintaged, annual load shares and the RPS energy deliveries will change from year to year based on the updated forecasts of vintaged, annual loads and the actual RPS energy volumes realized in each year of the allocation term. LSEs that accept allocated RPS energy may choose to re-sell such allocated RPS energy outside of the VAMO process. For an example of how short-term and long-term allocations will work, refer to Appendix I.

The Co-Chairs propose that LSEs electing long-term allocations will receive long-term RPS credit, provided that, at the time of election, the longest remaining non-UOG or evergreen contract within the LSE's vintage has at least ten years remaining on its term. Additionally, LSEs will only receive long-term credit for the allocated RPS energy if the IOU's original contract was at least 10 years in term.

Certain PCIA-eligible LSEs' customers may have departed many years ago, and therefore those LSEs may be ineligible to ever participate in the IOUs' long-term allocations, if less than ten years remain on any contract in their PCIA vintage as of the RPS VAMO implementation date. However, because the IOUs' contracts were originally procured on behalf of these bundled service customers, and these customers have continued to bear cost responsibility through the PCIA, the Co-Chairs propose that, in the first election period only, if the remaining term of the longest, non-evergreen contract or UOG life within an LSE's PCIA vintage is less than ten years, then the LSE will be grandfathered to receive the same long-term credit for the allocated RPS energy as the IOU would have received from those contracts within its portfolio, provided at least one contract in the vintage had a term of at least 10 years in length. This will prevent the destruction of value from the long-term RPS attributes that rightfully should belong to these customers. The Co-Chairs agree that this grandfathering proposal should not apply to sales or other allocation approaches outside of PCIA, as this is a unique situation that resulted from the IOUs' mandates to procure RPS generation as ordered by the state, and in their role as the primary energy service providers in the state at the time of such procurement. Further, PCIA represents a unique situation in that all of these customers remain customers of the IOU through the provision of transmission and distribution services.

c) RPS Energy Market Offer Process

The Co-Chairs propose that all unallocated RPS energy for the prompt year will be offered for sale through an annual Market Offer process to be held by the IOU. Within those unallocated volumes, the IOUs will offer up to 35 percent of each LSEs' annual declined allocation share as long-term sales, not to exceed 35 percent of that LSE's total forecasted allocation share for the remaining term of the PCIA. Long-term sales will be offered for terms ranging from 10 years to the life of relevant PCIA vintages. SCE proposes that long-term sales should be structured so as to convey a percentage slice of the unallocated RPS portfolio vintages. The balance of unallocated RPS energy is to be offered for sale with a one-year term beginning on January 1 following the Market Offer. For an example of how the long-term sales threshold determination works, refer to Appendix H in Tables 28 and 29.

The Co-Chairs propose that the Market Offer process will be conducted using Commission pre-approved mechanisms for the solicitation's administration, valuation, selection, and contracting, which will be approved via each IOU's submittal of updates to its RPS Procurement Plan. Additionally, an IE will monitor the solicitation and the CAM group will be consulted on offer selections. The Market Offer process will be open to all market participants, including the IOU holding the market offer process. If the IOU is participating in its own market offer, the IOU must (i) submit bids to the IE and ED in advance of the Market Offer launch or (ii) establish dual procurement teams separated by an ethical wall, with monitoring by the IE to ensure a fair and non-preferential process. Additionally, the Co-Chairs propose that ED compile an annual report following the completion of the IOUs' Market Offer solicitations, which will summarize the results of the auctions and the potential impact that the cap on long-term sales had on realized RPS energy market value. The Co-Chairs propose that the long-term sales cap be re-evaluated after two years to determine whether it should be adjusted.

The Co-Chairs propose that all contract pricing be structured through a flat (*i.e.*, no annual escalation) index + REC price transaction structure. Each IOU will choose which contract type it will use for the Market Offer, which will include slice-of-generation contracts in which deliveries are contingent upon the actual amount of generation within the RPS portfolio and offer an hourly delivery profile consistent with the profile of the IOU's aggregate, declined RPS allocations. Parties purchasing RPS energy through the Market Offer process will receive the RECs, the ability to claim the energy on their PCL, and if entering into a long-term contract, the right to claim the RPS energy in the IRP process based on the hourly generation profile of the unallocated RPS portfolio from which the sale is sourced and receive long-term contracting credit for RPS compliance. To protect PCIA-paying customers against defaults, the IOUs will require appropriate credit, collateral, netting agreement terms, or other commercial arrangements.

The Co-Chairs propose that the valuation and selection process for the Market Offer must be transparent and limit discretion by the IOUs, as to not have LSEs question the rationale for the selections. The Co-Chairs propose that the Market Offer process evaluate bids based solely on the highest price offered, with no discount rate applied to valuation of long-term sales, and that the IOUs select offers in merit order until all unallocated RPS energy has been sold (subject to the long-term sales cap described above).

In the event that unsold RPS energy remains after the conclusion of the Market Offer process, the unsold RPS energy volumes will be re-distributed among all LSEs at no cost and on a pro-rata basis according to their forecasted, vintaged, annual load shares. The re-allocated RPS energy attributes will be treated as sales at $0/MWh and will be reported, along with the volumes re-allocated, by the IOUs to ED for the purposes of establishing the RPS MPB. This treatment ensures parties that declined allocations get the benefits of the RPS energy for their own use or re-sale, and ensures parties taking allocations are not unfairly impacted.

On a monthly basis throughout the flow year, the IOUs will calculate the allocated quantity of RPS energy delivered to each LSE and charge those LSEs for their allocated volumes as described more fully in Section V.H.2. Within 120 days following the end of each flow month, the IOUs will convey the RECs to buyers from the Market Offer and to LSEs that have elected to take allocations.[33]

3. Rationale for Consensus Proposal

a) VAMO is Reasonable

The Co-Chairs propose that the RPS VAMO mechanism provides an equitable means by which LSEs can elect to receive RPS energy directly as an allocation, have their customers receive economic consideration through PCIA rates, or choose a blend of the two options to suit their specific needs. Additionally, in the interest of protecting customer value, the Co-Chairs have developed mechanisms to enable the sale and/or allocation of long-term RPS attributes and preserve the RPS energy's REC, PCL, CNS, and PCC attributes, which can be transferred through allocations or sales. However, to remain consistent with existing statute, the preservation of long-term RPS attributes will require long-term commitments, as discussed below.

b) Long-Term Allocation Proposals are Reasonable

The Co-Chairs have developed a proposal for the treatment of allocations and sales that is compliant with existing statutory requirements for the preservation of long-term RPS credit. This proposed mechanism, wherein a long-term allocation must last for at least 10 years and through the end of the term of the longest contract in the PCIA vintage, with the exception of evergreen contracts and UOG resources, is reasonable as it reduces the risk that attributes will be stranded in the future. The proposed exclusion of UOG and evergreen resources is reasonable as LSEs could otherwise be bound indefinitely to take RPS energy from the IOUs through allocations, which would inhibit LSE procurement flexibility. The Co-Chairs suggest that the grandfathering proposal for long-term allocation elections made in the first election period is reasonable, as it permits certain LSEs who might otherwise be excluded from long-term RPS

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[33] RECs are created within 90 days, so this is 30 days from REC creation.

treatment because they departed from the IOU many years ago, to realize the long-term RPS value that was procured on behalf of their customers. The Co-Chairs do not believe that this grandfathering proposal should be precedential in any other setting, as the PCIA is unique in its treatment of the IOUs' historically mandated procurement.

c) Market Offer Proposal is Reasonable

The Market Offer process proposed by the Co-Chairs is reasonable as it comports with existing IOU standards and requirements for conducting solicitations. The contract pricing requirements are reasonable for eliminating potential conflicts of interest or questions around IOUs' decision-making and judgement in administering the Market Offer processes. Monitoring by an IE and consultation on offer selections with the CAM group provides transparency and protections for other LSEs to ensure that IOUs are fairly and reasonably conducting the Market Offer process. The Co-Chairs propose the use of the CAM group (rather than Peer Review Group ("PRG")) for review of the PCIA Market Offer results with the expectation that CCAs and other PCIA-eligible LSEs would be eligible to join the CAM group by hiring independent, non-market participants as their proxies and be subject to rules governing market sensitive information.

It is reasonable to permit the IOUs to participate in their own Market Offer process, provided ethical walls or advance bid protections exist and are monitored by IE. The IOUs' participation allows for greater competition for RPS energy and thus maximizes value realized in the Market Offer, which will aid in reducing PCIA rates for all customers. Additionally, it affords IOUs the same opportunity as any other market participant to procure RPS energy that is declined by PCIA-eligible LSEs, thus permitting the IOUs to advance their clean energy goals on behalf of bundled service customers. The proposed protections will ensure that the IOUs' participation in the Market Offer does not grant them an undue advantage relative to other market participants.

The Co-Chairs suggest that it is reasonable to cap long-term sales, initially at 35 percent. Such a cap will help prevent issues that could arise when load migration, coupled with greater long-term sales volumes and portfolio optimization activities, may cause challenges for the IOUs to fulfill the volumes required to meet each LSEs' eligible allocation share. The Co-Chairs recommend that ED review the long-term sales cap after two years to ensure that it is not overly limiting.

The Co-Chairs propose that it is reasonable for the IOUs to evaluate the appropriate mix of RPS contract types to make available for sale in the Market Offer to protect the ability to fairly allocate attributes across LSEs, while maximizing customer value. Each IOU's portfolio is composed of different resources and technologies, and thus may require different RPS contract types to balance allocations against Market Offer sales.

Additionally, it is reasonable to require credit, collateral, netting agreements, or other similar commercial arrangements to prevent defaults from raising costs for all customers. If an LSE fails to pay for delivered RPS energy, the IOU could refuse to deliver the RECs corresponding to such uncompensated energy. However, the RECs following that RPS energy would be de-valued from PCC1 to PCC3, as they would no longer be bundled with the energy, since the resources would have already generated such energy. Without appropriate collateral, the buyer's failure to pay would destroy customer value without recourse, leading to higher PCIA rates.

Finally, it is reasonable to re-allocate unsold RPS energy to LSEs that chose to sell, as the attributes were procured originally on behalf of their customers and those customers should realize the value associated therewith. If the LSEs are allocated the unsold RPS energy, they may thereafter seek to monetize those attributes themselves to realize value for their customers.

E. <u>GHG Emissions from PCIA Resources</u>

1. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs propose that the treatment of the IOUs' PCIA-eligible, GHG-emitting resources be dealt with in the same fashion as the IOUs' CAM-eligible, GHG-emitting resources are treated on the PCL. The CEC now requires IOUs to report only their bundled load share of the emissions resulting from the dispatch of GHG-emitting CAM resources. The balance of the energy dispatched, and its resultant emissions, is treated as unspecified power within the state of California. Any LSE, other than the contracting IOU, whose customers pay for the procured CAM resources is not directly attributed the GHG emissions resulting from their proportional share of output from the CAM resources, but instead shows unspecified power on the PCL to the extent that any retail sales are not accounted for with procurement contracts. The emissions factor associated with this unspecified power procured from the CAISO market incorporates the emissions resulting from the share of the CAM resources that is not attributed to the IOUs' bundled load customers.

The Co-Chairs propose that the Commission request that the CEC explore expanding the current regulations pertaining to CAM resources to also include PCIA resources. However, one distinction for the PCIA resources relative to CAM resources would be that the determination of the share attributable to the bundled load customers should not be based upon the CAM load share, but rather should be based upon the IOU's actual, vintaged annual load (MWh) share of the energy generated by the PCIA-eligible, GHG-emitting resources. This emissions allocation methodology aligns with the concepts put forth for the allocation of GHG-free energy and RPS energy and is an equitable mechanism for showing the energy intensity associated with serving bundled service customers from their share of the PCIA portfolio.

2. Rationale for Proposal

The proposal to have the IOUs show only their vintaged load share of the emissions relating to the PCIA-eligible, GHG-emitting resources is reasonable as it creates an equitable means of demonstrating the energy intensity associated with serving bundled service customers. The proposal also aligns with the existing precedent set by the CEC's implementation of new regulations pursuant to AB 1110 for treatment of the emissions relating to CAM resources. Allowing the IOUs to only report the bundled service load's vintaged share of such energy on the PCL is a more equitable manner for treating the GHG emissions from PCIA resources.

F. Allocation Forecasting

While touched upon above, in the interest of articulating the specific mechanisms proposed for the determination of allocation shares, the Co-Chairs lay out the specific forecasting steps below.

1. Co-Chair Consensus Allocation Methodology

a) Vintaged Load Shares

The Co-Chairs propose that the forecasts to be used for determining each PCIA-eligible LSE's allocation load shares will be the load forecasts for the upcoming calendar year that are submitted to and calibrated by the CEC and CPUC pursuant to the existing RA process. However, to account for the vintaged nature of the PCIA mechanism, the Co-Chairs propose to add the requirement for LSEs to provide their historical load information and load forecasts pertaining to each month and each vintage (i.e. each year of departure) of customers that departed from IOU bundled service. New processes and load forecasting methodologies will need to be developed to calibrate LSE's vintaged, monthly coincident-peak- (MW) and annual- (MWh) load shares, analogous to the calibration that takes place today to determine the forecasted, monthly, coincident-peak-load for California and to fairly allocate the RA procurement requirement across all LSEs. In July, following the load forecast calibration, ED will send a letter to each LSE indicating its preliminary vintaged, monthly, coincident peak-load (MW) share and vintaged, annual load (MWh) share, which can be used to inform each LSE of their estimated allocation of PCIA-eligible RA capacity and RPS and GHG-free energy, respectively. In September, the ED will send another letter to each LSE updating these published calculations to reflect the final allocation volumes that each LSE would be eligible to receive. For examples demonstrating how vintaged peak-load and annual load share determinations work, refer to Appendix H in Tables 2 to 5.

b) Vintaged Product Positions

The IOUs will be required to provide PCIA-eligible LSEs with an indicative, vintaged PCIA-eligible RA position forecast in April to aid in their portfolio planning and procurement activities. However, the final, total capacity that is to be allocated among all PCIA-eligible LSEs will be equal to each IOU's monthly PCIA-eligible Local and System and Flex RA capacity available as of the CAM capacity filing deadline in July, as further adjusted for any modifications by the CAISO to the resources' NQC or EFC in the final NQC/EFC publication, which currently is published in late September, except as provided below with respect to use-limited resources. This final, monthly total quantity of capacity for each type of RA will be shown by the IOU and will be used by ED to determine the actual PCIA capacity available for allocation to each LSE.

With respect to use-limited resources, the total capacity available for allocation may be reduced by the IOUs on the basis of forecasts for the particular facility, provided (1) the IOU justifies the difference in capacity value in workpapers, or otherwise, submitted in the ERRA Forecast of Operations application, and (2) if the IOU later identifies that additional capacity is available for RA purposes, the IOU may (a) use such capacity for substitution relating to the PCIA Showing, (b) re-allocate such capacity to PCIA-eligible LSEs at $0/kW-mo cost, or (c) sell the capacity with revenues flowing to the resource's vintaged PABA sub-account.

For RPS and GHG-free energy, the actual deliveries are contingent upon the actual hourly production of the resources in each vintage over the course of the calendar year, including any IOU portfolio optimization activities. For examples showing how the allocation and re-allocation would work for each product pool, refer to Appendix H.

2. <u>Rationale for Consensus Proposal</u>

a) <u>Proposed Allocation Methodology is Reasonable</u>

The Co-Chairs submit that the proposed allocation methodology is a fair and equitable mechanism for distributing PCIA-eligible products to LSEs serving PCIA-paying customers. For RA, the application of the forecasted, vintaged, monthly, coincident peak-load (MW) share as identified through the RA process best reflects the actual RA obligation shares of each LSE and aligns cleanly with existing RA processes, while providing RA position stability to LSEs accepting their allocations throughout the course of the year. Similarly, for RPS energy and GHG-free energy, using the forecasted, vintaged, annual load (MWh) share best reflects the actual requirements needed to serve each LSE's customers and provides more certainty about the volumes to be received. Further, allocating the products on a vintaged basis aligns the distribution of the products with the customers for whom they were procured, and thus allocates value equitably to those customers who are paying for the costs of such contracts or UOG resources. It is also reasonable to use 10 percent allocation election increments to allow LSE optionality while preventing undue administrative burden in tracking LSE elections. This optionality allows LSEs to manage their procurement more freely by enabling customized solutions composed of a mix of allocated RPS energy and credits realized in PCIA rates.

The Co-Chairs explored using a cost-share mechanism for allocation of RA and energy attributes but identified challenges in being able to accurately forecast LSEs' cost-shares. When taken together, utilizing a peak-load (MW) share for RA and an annual load (MWh) share for RPS and GHG-free energy approximates LSEs' customers' cost responsibilities relating to capacity and energy procurement, as these capacity, RPS, and energy procurement costs are factored into each customer segment's PCIA rate allocation factors.

Allocating the PCIA-eligible RA position volumes as of the July CAM capacity filing, as further adjusted for changes by the CAISO to the resources' NQC or EFC, is reasonable. The timing for finalizing the allocation volumes allows the IOUs to conduct portfolio optimization with the objective of maximizing customer value, while freezing the allocation volumes early enough for PCIA-eligible LSEs to have an understanding of how much credit they will receive through the PCIA Showing so they can act to procure their residual RA positions in the market. Further, freezing the allocation amounts ensures that parties will not end up short at the year-ahead showing or thereafter due to the IOUs' portfolio optimization actions. Efficiencies are gained by leveraging the existing CAM process for the IOU to publish the volumes available for allocation.

Allocating RPS and GHG-free energy on the basis of the actual deliveries is also reasonable, as it ensures that all RPS and GHG-free energy is accounted for and fairly distributed among the PCIA-eligible LSEs. This also permits the IOUs to continue to pursue portfolio optimization opportunities throughout the flow year, which is reasonable, as it permits the IOUs to maximize the value of the portfolio. Additionally, aligning with the RA process helps mitigate potential gaming by LSEs to receive greater RPS allocation volumes because higher load forecasts, while not perfectly correlated, could result in higher peak-load forecasts, thus causing higher RA procurement obligations.

G. RPS and GHG-Free Energy Production Disclosures

1. Co-Chair Consensus Proposal

The Co-Chairs have agreed upon certain confidential, forecasted and actual generation information pertaining to the RPS and GHG-free energy portfolio that the IOUs will provide to PCIA-eligible LSEs to enable them to conduct portfolio planning, subject to execution of a Non-Disclosure Agreement ("NDA") acceptable to the IOU by the PCIA-eligible LSE. The IOUs will provide (a) the most recent three years of historical, aggregated, hourly production data by RPS, nuclear, and/or non-nuclear pool; (b) the CAISO resource identifications for all resources in each pool; and (c) the following forecasts of aggregated production data by vintaged pool:

1. Aggregated, total year-ahead ERRA forecast;
2. Aggregated, year-ahead ERRA forecast of the total production for each of the 12 months; and
3. Quarterly updates for remaining balance of year of the monthly total, aggregated production.

The forecast will be provided as is, without any warranty. If aggregation is not possible, the IOUs will provide the pools' production information on a historical basis only. Aggregations will require at least five (5) resources, unless the IOU waives such requirement, which shall not be construed to establish precedent for future aggregations.

2. Rationale for Consensus Proposal

CalCCA and Commercial requested, and SCE is willing to provide, sufficient information on the RPS and GHG-free energy allocations for PCIA-eligible LSEs to properly perform their procurement planning activities. However, in the interest of protecting market sensitive information, the IOUs must protect confidential information, such as unit-specific production amounts and planned outages. The Co-Chairs believe that they have proposed sufficient information to be exchanged under NDA to permit LSEs to perform their procurement planning and for the CEC to conduct its audits, as necessary, for verification of PCL reporting.

H. Proposals for Modifications to PCIA Ratemaking

1. Background on Ratemaking Decision in Working Group 1

The PCIA calculation is a product of decisions dating back to 2002, with its most recent formulation adopted in D.18-10-019 and D.19-10-001. In its simplest form, the PCIA calculation can be shown as follows:

While the WG 3 proposals will not affect portfolio costs or billing determinants, the proposals require modification of the portfolio value that is offset against costs to determine the indifference amount.

The final portfolio value, today, is calculated as the value of the resources retained in the bundled utility portfolio plus the value obtained in the market for resources in excess of bundled requirements. The bundled portfolio value is determined as (1) the Local, System, and Flexible RA capacity and RPS energy retained for bundled service customer load (i.e., not offered for sale to the market) multiplied by the respective MPBs for each product plus (2) the value received in the market for the sale of energy and ancillary services; Local, System, and/or Flexible RA capacity; and RPS energy. The portfolio value is forecasted in each IOU's ERRA Forecast of Operations application before the start of a PCIA rate year and is then subject to a true-up in the November Update to ERRA Forecast application, with any over- or under-collection recovered in rates the following year. All elements of the calculation are subject to true-up, including load, generation, sales revenues, and MPBs. Costs and revenues are charged and credited on a vintaged basis to the PABA's vintage-specific sub-accounts, with departing load customers responsible for the net costs realized from their vintage and prior through their PCIA rates.

A cap of $0.005/kWh was established for the maximum PCIA rate rise permissible year-over-year, with a 10 percent under-collection trigger threshold established. If an IOU were to reach a 7 percent under-collection as the result of capped PCIA rates, the IOU would be required to file an application with the CPUC proposing a revised PCIA rate to bring the projected under-collection balance below 7 percent for the remainder of the calendar year.[34]

2. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs propose using the existing PCIA framework and benchmarks to implement the consensus allocation-based approaches with certain modifications:

- All Local RA attributes will be valued at $0/kW-mo for PCIA ratemaking. Because all LSEs will receive Local RA attributes in accordance with their pro-rata share, no offset of the MPB against the full costs of Local RA is required in the PCIA formula.
- The Co-Chairs propose that in the year the change in cost-recovery treatment for the Local RA allocation is implemented, the Commission should authorize the IOUs to exclude the additional revenue requirement from the PCIA rate cap adopted in D.18-10-019 to account for this change. This exclusion would only apply to the first year the Local RA allocation is implemented, to reduce the risk that the change will cause the IOUs to trigger the PCIA cap.
- Regardless of whether LSEs accept or decline their allocations, the GHG-free energy will continue to receive the brown power MPB for the purposes of setting forecast rates and realized CAISO market revenue true-up in PCIA calculation as an offset against total costs.

[34] Alternatively, an IOU is authorized to notify the Commission through an advice letter submittal, instead of an expedited application, when the IOU reasonably believes that the balance will self-correct below the trigger point within 120 days of the submittal.

- System and Flex RA and RPS energy allocations will be treated like sales in the existing framework. LSEs electing to accept allocations will be required to pay the IOU the applicable year's MPB for the attributes received and may be required to meet certain credit or collateral requirements, netting agreements or other commercial arrangements. These payments will be recorded in PABA and will offset costs in the PCIA. IOUs will also be required to pay for their allocations via a debit from the ERRA balancing account and a credit to PABA.
- Any sales revenues from Market Offer processes will also be recorded in PABA, in a similar manner to how sales are recorded today, although the accounting for sales revenues will need to account for the vintages of the LSEs that declined their allocations by allocating revenues pro rata across vintages in proportion to the declined volumes in each vintage.
- Unsold System and Flex RA attributes and RPS energy will be allocated at no cost to all PCIA-eligible LSEs on the basis of their forecasted, vintaged, peak- and annual-load shares.
- The methodology for calculating the MPB for System and Flex RA and RPS energy developed in the Phase 2, Track 1 process of R.17-06-026 will be retained, but will be updated to incorporate the unsold, re-allocated volumes at $0 into the determination of the MPB values.

Under this proposed implementation, the existing ratemaking construct adopted by D.19-10-001 has not changed substantially. Net costs to be recovered through PCIA rates are to be determined according to the following formula:

Total Contract and UOG Costs[35]

(-) CAISO revenues

(-) Product sales revenues

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[35] Including costs to substitute or mitigate availability risks, as discussed in Section V.B.2.g.

(-) Quantity of products allocated multiplied by PCIA attribute MPB

(+) under-collected amounts or (-) over-collected amounts in PABA and/or the PCIA undercollection balancing account ("PUBA")

= Net Above Market Costs

Refer to Appendix H in Tables 56 to 59 for examples of how the ratemaking mechanism works for each product type.

3. <u>Rationale for Consensus Proposal</u>

During the WG 3 discussions, the Co-Chairs discussed two ratemaking options.

SCE and Commercial initially proposed an alternative approach whereby PCIA rates receive a \$0 value for each attribute (*i.e.,* eliminate the MPB for each product), thus resulting in full cost recovery through PCIA rates for each product contemplated in the VAMO process. Then, to realize the economic value directly associated with unallocated attributes sold in the Market Offer, LSEs would receive a payment directly from the IOU associated with the LSE's share of such sales revenues. This proposal became known as Ratemaking Option 1 in the Co-Chair discussions and in the workshop presentations. While SCE and Commercial agree that this approach has some advantages, one disadvantage with this approach is that, as the full contract costs would be recovered through the PCIA rate with no offsetting attribute values, the PCIA rates would increase relative to today's PCIA rates.

CalCCA had concerns over Ratemaking Option 1, as it could lead to dramatically higher PCIA rates. CalCCA instead advocated for Ratemaking Option 2, which the Co-Chairs ultimately reached consensus upon for the System and Flex RA and RPS energy VAMO proposals. This proposal also received general consensus among stakeholders at the Third Workshop and in informal comments received. Ratemaking Option 2 preserves the existing framework established by D.18-10-019 but expands eligibility for purchases of attributes at the MPB to all PCIA-eligible LSEs on the basis of their allocation shares.

The Co-Chairs aligned upon valuing Local RA at \$0/kW-mo as all LSEs will receive their share of the Local RA attributes, and there are no sales to be performed to credit against

PCIA costs. Eliminating the MPB simplifies cost recovery and ensures full costs are recovered. A consequence of eliminating the MPB associated with Local RA is that PCIA rates may rise. In this case, the Co-Chairs recognize that this increase in PCIA rates is accompanied with an allocation of attributes that provides a concrete benefit associated with the increased cost, and justifies a one-time adjustment to the PCIA rate cap to exclude the impacts of this change in the Local RA MPB methodology.

No changes are proposed to GHG-free energy cost recovery, regardless of whether LSEs accept or decline allocations, as customers already receive the full costs and benefits associated with the nuclear and non-nuclear GHG-free resources economically through rates.

Reallocating unsold System and Flex RA and RPS energy at no cost to LSEs ensures that all LSEs receive the value associated with the unsold attributes. Those LSEs can choose to use the unsold volumes for their own compliance purposes or may choose to sell the attributes in the secondary market themselves. The unsold attributes should be incorporated into the MPB to ensure that the MPB appropriately reflects the market value of the attributes, which permits more equitable treatment between LSEs receiving unsold attributes and those LSEs that must pay the MPB for allocated attributes.

Examples of how the ratemaking mechanisms for each product type, and how Ratemaking Option 1 and Ratemaking Option 2 compare are included in Appendix H, Tables 56 to 59. A graphic illustrating the difference in cost recovery is included in Appendix G.

I. <u>Co-Chair Proposal for Transfer of Attributes on PCL</u>

The Co-Chairs propose that allocations of RPS and GHG-free energy will be structured to comply with existing CEC requirements for PCL reporting. LSEs accepting allocations will be required to sign contracts or election confirmation forms indicating forward commitments to procure the allocated attributes. The bundled energy will be delivered by the IOU or its counterparties, as applicable, to the CAISO market. Following the flow year, the IOU will identify the sources and volumes of energy delivered to each LSE, which will permit the LSE to conduct its CEC reporting.

J. Treatment of PCIA Allocations and Sales within IRP

1. Co-Chair Consensus Proposal

The Co-Chairs propose that LSEs may receive IRP credit for their forecasted, vintaged load shares of the hourly generation of each allocated product from the IOUs' PCIA portfolios through the end of the term of their PCIA vintage(s). This proposal operates under the assumption that each LSE will, by default, accept its allocation within the context of IRP treatment, which is reasonable as the PCIA resources have already been contracted for by the IOUs on behalf of bundled and departed load customers, and, to a large extent, already reflect generating facilities that are in operation. Accordingly, if any LSE were to choose not to take its allocation for any given year, the amount of capacity and RPS or GHG-free energy in the system remains unchanged, as it is simply transferred to another entity, and does not alter the volumes of each product considered within the IRP's Reference System Plan ("RSP").

The short-term sales of RA and RPS energy through the Market Offer and the re-allocation of GHG-free energy will not convey long-term IRP credit to the buyers or LSEs receiving a re-allocation, as the term of such sales or re-allocations will be for only one year. However, for RPS energy, if an LSE elected to decline its allocation, and a portion of such allocation was sold long-term in the Market Offer process, then those RPS energy volumes sold long-term would (i) convey IRP credit to the buyer in the Market Offer process, (ii) be unavailable for the declining LSE to receive as an allocation in the future, and (iii) not be available to the declining LSE in IRP.

Appropriate procedures will need to be developed within the IRP OIR to provide LSEs IRP credit in accordance with the consensus proposals.

VI.

SCOPING ISSUE 2: STRUCTURES, PROCESSES, AND RULES GOVERNING PORTFOLIO OPTIMIZATION

A. Existing IOU Portfolio Optimization Activities

The IOUs aim to maximize their portfolios' value for customers by seeking out opportunities to reduce customer costs, when feasible, without sacrificing the integrity of their respective portfolios. Portfolio optimization activities require judgement, a consideration of current market conditions, adherence to policies and Commission rules, and negotiation with counterparties to be successful. Portfolio optimization activities are not intended to undermine or negate the original terms of the contracts without both parties' agreement. Further, the IOUs cannot unilaterally terminate a contract, unless events occur giving the IOU contractual rights to do so.

The opportunity to modify a contract typically arises under three circumstances: (i) either party requests a contract modification; (ii) buyer and seller identify an opportunity for a mutual benefit; or (iii) a counterparty fails to perform. When any of these circumstances occur, the IOUs may pursue a contract amendment, termination, buy-out, assignment or other action with an eye towards providing a net benefit to customers. The IOUs utilize a variety of tools to manage their portfolios and the contracts therein, including, but not limited to, sales of resources and/or attributes, collateral reductions, economic curtailment, capacity reductions, contract buy-outs and other modifications. The details surrounding these activities are included in the IOUs' respective annual ERRA Review of Operations applications.

The Co-Chairs propose that the IOUs may optimize their respective portfolios of RPS and GHG-free energy resources at any time, but if such activities affect the allocations for the Delivery Year, the IOU must provide at least 60 days' prior notice of the transaction to PCIA-eligible LSEs to indicate the potential impact on expected allocation deliveries. The Co-Chairs recognize that sizable portfolio optimization transactions could have a significant impact to expected LSE allocations in a Delivery Year. As such, the Co-Chairs propose that IOUs should not reduce the expected RPS or GHG-free energy portfolio deliveries by more than 10 percent in the Delivery Year, unless otherwise mandated by the Commission.[36] There would be no limitation on potential portfolio optimization activities that would impact allocations in future years.

Non-resource specific sales of PCIA-eligible attributes that are conducted for the overall PCIA portfolio will affect all LSEs proportionally, with the volumes deducted pro rata from all vintages, as today. Such sales will not be conducted within the Delivery Year. There would be no limitation on potential sales activities that would impact potential allocations in future years. However, like any other LSE receiving an allocation, the IOUs may sell their bundled load's share of forecasted allocation volumes of any attribute, provided they disclose prospectively that such sales would accrue only to the bundled load's position.

B. Proposed Portfolio Reduction Process

1. Background on Portfolio Reduction Process

In D.18-10-019, the Commission instituted Phase 2 to "offer the promise of meaningful progress toward reducing the levels of above-market costs going forward."[37] While the VAMO optimizes the allocation of resources and will generate revenues to offset PCIA costs, it does not seek to reduce IOUs' overall portfolio size. For this reason, and as directed by the Phase 2 Scoping Memo, the Co-Chairs explored other potential mechanisms to provide greater structure around and transparency into the IOUs' efforts to reduce their overall portfolio costs.

Reductions in total portfolio costs can be achieved by modifying or terminating existing contracts. The Co-Chairs reached alignment on potential means of reducing contract costs through, among other things, contract buy-outs or assignments, which would remove resources entirely from the portfolio. The Co-Chairs propose that this may occur by the IOUs reaching out to their counterparties to solicit interest in fully assigning their contracts to other LSEs.

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36 For purposes of this limitation, contract management actions taken directly under the contract, such as responding to an event of default or exercising a contract option, do not constitute portfolio optimization.

37 D.18-10-019 at 129.

2. Co-Chair Consensus Proposal for Portfolio Reduction

a) Overview of Portfolio Reduction Proposals

The Co-Chairs propose that the IOUs will hold an RFI process with their RPS contract counterparties ("Sellers") for interest in two types of transactions: (i) a contract assignment or (ii) a termination that facilitates a re-contracting by the Seller to another LSE (both referred to herein as a "Contract Assignment"). The Co-Chairs propose that the RFI be conducted in 2021 and 2022 and every other year thereafter. Following the completion of the 2022 RFI, the Commission will determine the need for continuing to conduct the RFI every other year and consider any modifications to the RFI process. Additionally, the IOUs will solicit proposals for termination, buy-out, or amendment transactions unrelated to a Contract Assignment ("Contract Modifications").

b) Contract Assignment RFI Process

The Co-Chairs propose that the IOUs canvas their portfolio for Sellers interested in Contract Assignments. SCE proposes that in determining eligibility for this RFI, the IOUs may elect to exclude (i) contracts that are priced at or below 115 percent of the MPB, adjusting for RA and energy value; (ii) RPS contracts that if assigned, would result in a shortfall of RPS energy deliveries relative to the IOU's RPS compliance targets for any given year or would require the IOU to procure new long-term contracts in the next three years to meet its RPS compliance obligations; and (iii) contracts that are required to meet Commission mandates. The IOUs would request that Sellers indicate their interest by providing the IOU with their minimum requirements to consider a Contract Assignment with another LSE. The IOU will inform the market of Sellers' interest ("Interested Sellers") in Contract Assignments and will seek LSEs ("Prospective Buyers") interested in exploring the Contract Assignment and meeting Seller's expressed criteria for engagement (*e.g.* credit rating limitations, minimum term, etc.). The IOUs will match Interested Sellers with Prospective Buyers meeting the Interested Seller's minimum requirements and allow the Potential Buyers and Interested Sellers the opportunity to negotiate a Contract Assignment. Before the Interested Seller and Prospective Buyer begin negotiations for

Contract Assignments, each must execute an NDA with the IOU. Once NDAs are executed, and subject to Seller's consent, the IOU will provide Prospective Buyers with the Interested Seller's PPA and the last three (3) years of historical production of the project. Seller and Prospective Buyer may maintain the confidentiality of their negotiations and final terms and conditions, and neither the IOU nor the Commission may review the terms and conditions reached by Seller and Prospective Buyer, other than as required to comply with existing regulations. Following their negotiation, the Seller and Prospective Buyer may propose the terms of the negotiated Contract Assignment that would affect the IOU to the IOU for approval.

c) Contract Modification RFI

Coincident with the Contract Assignment RFI, the IOUs will request offers from their Sellers for potential Contract Modifications. Sellers may propose terminations, buy-outs, or amendments that result in net cost savings for customers. The IOUs will evaluate Sellers' proposals and will seek to negotiate agreements to amend or terminate the Seller's contract if desirable. The IOUs will file any successful agreements within their annual ERRA Review of Operations application or through an advice letter or other application, as appropriate and consistent with existing requirements, for Commission review and approval.

d) IOU Review and Approval

The Co-Chairs propose that with regards to Contract Assignments and Contract Modifications, the IOU has discretion, in its business judgment, to accept or reject any proposed transactions or arrangements, subject to Commission requirements. Further, SCE is concerned that it does not have the resources to effectively manage the hundreds of proposals that may be received. Therefore, the Co-Chairs propose that the IOUs be allowed to cap the number of active negotiations with counterparties each IOU will be required to enter into to 20 mutually exclusive offers from each RFI. SCE proposes that the IOU will need to evaluate offers received to determine which proposals to pursue. All transactions to which the IOU is a party will be subject to Commission approval, consistent with existing processes for contract review and approval. Any cost reductions arising from a Contract Assignment or Contract Modification will be reflected in PCIA rates for the vintage associated with the contract. Additionally, any payments made by the IOU in connection with a Contract Assignment or Contract Modification will be charged to the PABA sub-account corresponding to the resource's vintage.

SCE and Commercial propose that any contract termination payments be excluded from the $0.005/kWh annual PCIA rate increase cap, established by D.18-10-019, as the PCIA cap was intended to manage volatility year-over-year rather than one-time transactions that may artificially trigger the cap because of large buy-out or termination payments that result in greater savings in subsequent years. SCE and Commercial do not believe the upfront cost of buying out these contracts was intended to be factored into the cap, as this will increase the PCIA cost to customers and potentially trigger the cap every year, which SCE and Commercial believe is not what the Commission intended. CalCCA, however, disagrees on grounds that an IOU's responsibility to optimize its portfolio through the RFI is no more onerous than the requirement to optimize their portfolios today under AB 57 and the Standards of Conduct. In other words, the Commission was fully aware of the potential for buy-outs or buy-downs when it adopted the cap in D.18-10-019, yet chose not to make such transactions an exception from the cap.

IOUs will be required to provide all LSEs notice of how portfolio optimization activities may affect their allocations in flow year.

e) <u>Reporting on RFI</u>

Each IOU will file a report summarizing the results of the Contract Assignment and Contract Modification RFIs. The report will identify (a) the full list of Sellers notified for potential inclusion in the Contract Assignment process, (b) the list of contracts assigned, terminated or otherwise amended, (c) the material terms of any proposed Contract Assignments or Contract Modifications, (d) the net impact on the IOUs' bundled and PCIA-eligible, vintaged positions, (e) a list of Contract Assignment proposals rejected by the IOU and the rationale for each rejection, (f) contracts currently in negotiations, and (f) the net customer value realized.

3. <u>Rationale for Consensus Proposal</u>

While contract assignments, terminations, buy-outs or amendments may currently occur organically with a generator contacting the IOU or vice-versa, the consensus proposal for the Contract Assignment and Contract Modifications RFI processes present a proactive approach to conduct a mass outreach to the IOUs' contracted generators and potentially spark creative thinking on the part of those Sellers to propose mutually beneficial transactions. This proposed mechanism provides an additional opportunity for removal of excess resources from the IOUs' portfolios by allowing other LSEs an opportunity to contract directly with generators currently bound by IOU contracts. This consensus proposal essentially provides two "open seasons" for contract restructuring, with greater visibility provided through reporting into the actions taken.

VII.

SCOPING ISSUE 3: TRANSITION TO NEW STANDARDS

Issue 3 asks "[i]f the Commission were to adopt standards for more active management of the utility portfolios, how should the transition to new standards occur (*e.g.,* timeframe, process, etc.)?" The proposals laid out by the Co-Chairs within Issue 1, while seeking to minimize impacts to existing processes, result in some proposed changes and additions to existing processes. The Co-Chairs suggest that the majority of the aspects identified in the WG 3 proposals can be ruled upon within a WG 3 Decision within R.17-06-026. However, there are a number of other proceedings or rulemaking venues that will also be affected and must affirmatively rule upon changes that are being proposed by the Co-Chairs to implement the proposed allocation proposals. Below, the Co-Chairs outline the proposed steps that must be taken to implement the Co-Chairs' proposed processes for each of the products.

A. Co-Chair Consensus Proposal on Full Implementation Process and Timelines

Starting in 2021, the Commission should order the IOUs to publish, within their annual ERRA Forecast of Operations applications, and subject to the confidentiality protections afforded by D.06-06-066, their vintage-specific, PCIA-eligible: (i) monthly Local, System, and Flexible RA positions, differentiating among the specific RA categories (*i.e.,* local area, flexible category, etc.); (ii) RPS energy positions, including information about long-term contracts and

PCC status; and (iii) GHG-free energy positions, by nuclear and non-nuclear pool, for the term of each PCIA vintage. This information will increase transparency to PCIA-eligible LSEs about the available positions to be allocated in the allocation and VAMO processes, facilitating early portfolio planning activities that will minimize market disruptions upon implementation of the WG 3 Final Decision. The first anticipated publication of this information may take place in the June 2021 ERRA Forecast of Operations application, pending the timing of the WG 3 Final Decision.

The Commission should rule that the IOUs update their BPPs to reflect the necessary changes for implementing the Local RA and GHG-free energy allocations, and the System and Flex RA VAMO processes, including, but not limited to, permitting allocations and re-allocations, revising volume limits and price floors for Market Offer sales or re-allocations, establishing Market Offer valuation, selection, and review processes, etc. It is expected that the IOUs may update their BPPs within 60 days of a WG 3 Final Decision, with Commission approval possible within 90 days thereof. This timeline would establish the updated BPP authority in approximately Q2 2021.

The Commission should also require the IOUs to update their RPS Procurement Plans to request approval to, among other things, conduct the RPS allocations and market offer, including establishing timelines, bidding requirements, valuation methods, etc.; conduct allocations and re-allocations; enter into long-term (*i.e.,* 10 years or more) allocations and sales; use new contracts for the Market Offer sales; revise limits on volumes that may be allocated or sold; revise price floors; etc. It is anticipated that these changes could be ruled upon within the 2021 RPS Procurement Plan filings for RPS energy deliveries in 2022.

The Co-Chairs recommend that the Commission rule by June 2021 that Track 4 of the RA OIR, slated for December 2020, be scoped to explore (i) the modifications needed to the RA process and timelines to accommodate the completion of the System and Flex RA VAMO process and to provide sufficient time following the RPS energy and fall System RA and Flex RA Market Offer processes to implement the Market Offer results into the annual Update to

ERRA Forecast application in November; (ii) establishment of the PCIA Showing mechanism, which is needed for Local and System and Flex RA allocations; and (iii) methodologies for LSEs to submit and the CPUC and/or CEC to calibrate vintaged annual- (MWh) and peak- (MW) load forecasting, which is needed for each of the four product allocations proposed by the Co-Chairs. The Co-Chairs recommend that these topics be ruled upon by June 2021, and be implemented for the 2022 compliance filing year, which would allow for deliveries in 2023.

Additionally, PCIA-eligible LSEs may wish to have additional clarification provided by the CEC on how it will treat allocated RPS and GHG-free energy on the PCL. The Co-Chairs request that the Commission consult with the CEC to ensure guidance is provided on how allocations may be structured to meet requirements of Assembly Bill ("AB") 1110.

The Commission should require the IRP OIR to address (i) how to implement allocations of Local and System and Flex RA, RPS energy, and GHG-free energy into the development of the RSP; (ii) how vintaged peak- and annual-load share forecasting should work in this context; and (iii) how allocations will affect LSEs' procurement targets for the IRP cycle that will begin in 2022. The allocations can be implemented, however, in advance of determining the accounting for IRP purposes.

1. Local RA Allocation and System and Flex RA Voluntary Allocation and Market Offer Implementation Timelines

It is anticipated that the regulatory decisions required for implementing Local and System and Flex RA allocations and market offer processes, as applicable, may be decided by mid-2021. The Commission would determine in the RA OIR the necessary changes for the Local and System and Flex RA allocation proposals to be incorporated into the 2022 RA filing process for the 2023 compliance year. Thus, the Co-Chairs suggest that the VAMO for System and Flex RA may commence in 2022 for the 2023 compliance year. By the time the WG 3 Final Decision is expected to be issued, in Q4 2020, most LSEs will have met 100 percent of their Local RA compliance obligation for 2022 and 50 percent of their obligation for 2023. The Co-Chairs propose that Local RA allocation also be implemented in the 2022 filing year, but only for the 2024 and 2025 compliance years.

2. GHG-Free Energy Voluntary Allocation Implementation Timeline

The proposed voluntary allocation process for GHG-free energy relies upon the IOUs' BPPs being updated and having calibrated, forecasted, vintaged, annual-load shares for each LSE. The BPPs are anticipated to be approved by the Commission by approximately Q2 2021. The methodology for submitting and calibrating load shares is proposed to be decided within the RA OIR. This decision is not anticipated until mid-2021, and thus the forecasting requirements would be ready for implementation in 2022 for 2023. The Co-Chairs recommend that the proposed GHG-free voluntary allocation be implemented in 2022 for 2023.

Despite the fact that the RA OIR has to rule upon the proper methodology for submittal and calibration of LSEs' vintaged, annual load forecasts, the Co-Chairs believe that the GHG-free energy allocation is the simplest product to allocate. With some minor modifications, such as utilization of LSEs' actual, vintaged loads for the first year, rather than forecasted, vintaged loads, implementation of the GHG-free energy allocation could take place sooner than 2023. As an interim solution, the Co-Chairs propose that the IOUs could provide voluntary allocations to PCIA-eligible LSEs on the basis of either a forecasted load share or their actual annual load shares, as determined by the individual IOU. Pacific Gas and Electric Company ("PG&E") has already submitted a proposal for the sale or allocation of GHG-free energy to enable an interim process in advance of a WG 3 Final Decision.[38] SCE plans to offer a similar interim GHG-free energy allocation, which will be submitted for Commission review through an advice letter, and would enable voluntary allocations to PCIA-eligible LSEs on the basis of their actual annual load shares, starting within 30 days of Commission approval.

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[38] PG&E Advice Letter 5705-E.

3. RPS Energy VAMO Implementation Timeline

The RPS VAMO process will depend on the Commission ruling upon the IOUs' RPS Procurement Plan updates to incorporate the RPS VAMO process. The Co-Chairs propose that the IOUs file their proposed changes in the next RPS Procurement Plans following the WG 3 Final Decision, which would be expected to be ruled upon in late-2021 for RPS energy deliveries in 2022. The RPS VAMO process will also rely on the RA OIR to rule upon the appropriate methodology for LSEs to submit and the CPUC and/or CEC to calibrate LSEs' vintaged, annual load forecasts. This process is anticipated to be ruled upon in 2021 for implementation in the 2022 RA filing year for the 2023 compliance year. Thus, the Co-Chairs anticipate that the RPS VAMO process may not be fully implemented until 2022 for deliveries in 2023.

4. Proposed Ratemaking Implementation Timeline

The Co-Chairs propose that the WG 3 Decision is the appropriate venue to update the Ratemaking requirements from D.19-10-001 to accommodate the Co-Chairs' proposal on appropriate ratemaking treatment within the PCIA. The change in ratemaking for each product should be effective coincident with the year in which such product would first be subject to the allocation or VAMO treatment contemplated by WG 3. The Co-Chairs contemplate that in the case of the VAMO, the results of the Market Offer process will be available prior to setting PCIA rates in the IOUs' November Update to ERRA Forecast applications, and thus should be incorporated into the updated MPB for the applicable product type.

B. Interim Implementation Proposals

1. Non-Consensus Interim RA Implementation Proposal

CalCCA and Commercial Energy propose that Local and System and Flex RA could be allocated beginning in 2021 for the 2022 System and Flex RA compliance year and the 2023 and 2024 Local RA compliance years pursuant to the following steps:

- Non-IOU, PCIA-eligible LSEs will meet and confer with the IOUs following the existing process prior to the initial year-ahead load forecast deadline in April 2021.

- CCAs and LSEs will provide IOUs with vintaged, monthly peak load forecasts for each of their vintages, totaling to their overall peak load.
- Parties will seek to agree on vintage peak load forecasts. If differences cannot be resolved between an IOU and an LSE, differences will be resolved through the CPUC mediation process.
- Allocations will be made based on the vintaged load forecasts, and will include 2022 System and Flex RA and 2023/2024 Local RA.
- By the end of July 2021 the CPUC will publish the preliminary RA obligations. The IOUs will apply the vintaged load shares to the PCIA-eligible RA positions to estimate the eligible vintage allocations for each LSE.
- Within 5 business days of receiving the initial RA obligations, the IOUs will notify each LSE of their eligible RA allocation volumes.
- LSEs will have 5 business days to submit their System and Flex RA allocation elections.
- Local RA allocations will be mandatory and the Co-Chairs' proposed ratemaking treatment will be recovered in 2023 and 2024 calendar years from customer PCIA rates.
- The RA allocation will be performed through the PCIA Showing.
- Trading will only be permissible if a suitable mechanism is worked out.
- LSEs receiving the System and Flex RA allocations will pay the IOU at the relevant MPB. Revenues will be treated like sales for purposed of PABA accounting.

SCE opposes an early or interim implementation for Local and System and Flex RA allocations. The IOUs need sufficient time to realign their portfolios to account for considerable increase in showing obligations, particularly if secondary trading of the PCIA Showing is unavailable.

2. Non-Consensus Interim RPS Energy Implementation Proposals

The Co-Chairs propose that an interim RPS voluntary allocation approach be pursued on the basis of LSEs' actual, vintaged, annual load shares and without a Market Offer process. Allocations would be treated as sales in the PCIA methodology at the RPS MPB. Declined allocations would remain with the IOU. Any RPS energy held by the IOU would continue to be treated in accordance with D.19-10-001. The Co-Chairs request the Commission specify that during this transition period excess RPS generation, excluding banked RECs, may be valued at $0/MWh for purposes of the PCIA only to the extent that it (i) is offered for sale by the IOU, (ii) remains unsold, and (iii) is in excess of the IOU's interpolated annual RPS compliance target.

CalCCA and Commercial propose that changes needed to the IOUs' RPS Procurement Plans could be accomplished via a Motion to Update, which could be requested as soon as practical following the WG 3 Final Decision with allocations to commence no less than 30 days following approval, thus permitting allocations to begin in 2021.

SCE proposes that interim RPS energy voluntary allocations could commence deliveries as early as 2022, provided appropriate timelines are allowed for updates to RPS Procurement Plans, receipt of necessary regulatory decisions, and for the market to prepare for the new requirements. To the extent that implementation of such interim RPS energy allocations would jeopardize the IOUs' abilities to meet their RPS compliance requirements, cause undue cost increases, or cause cost shifts to bundled service customers, the IOUs may petition the Commission to delay implementation. In addition, the IOUs will need to consider how to manage or sell their excess RPS energy positions for 2021 prior to receiving a WG 3 Final Decision, creating potential conflicts with requirements to conduct earlier allocations.

VIII.

SCOPING ISSUE 4: SHAREHOLDER RESPONSIBILITY

This section addresses the question of whether the Commission should consider new or modified shareholder responsibility for future portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards, and whether the ERRA or General Rate Case ("GRC") proceedings are the appropriate forums to address prudent management of portfolios.

A. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs do not propose new or modified IOU shareholder responsibility for alleged portfolio mismanagement. However, the Co-Chairs agree that each IOU should file a report on its implementation of the newly proposed RFI process (see Section VI.B.2.e above) and outcomes thereof, including identification of rejected offers and the bases for rejection. Additionally, the Co-Chairs agree that the IOUs shall report in the annual ERRA Review of Operations application (1) material events of defaults and any termination rights and any actions taken with respect thereto in a single section consistently formatted in each IOU's filings; and (2) cost savings received from active portfolio management.

B. <u>Rationale for Consensus Proposal</u>

The Co-Chairs agree that the information proposed for inclusion in the RFI report, as noted above, is reasonable. Moreover, any resulting assignment, modification or termination of a contract pursuant to the RFI process would be subject to Commission review and approval in the ERRA Review of Operations or other application or advice letter for cost recovery purposes consistent with existing requirements.

C. <u>Non-Consensus Proposal</u>

The Co-Chairs were unable to reach consensus on the timing, frequency, and venue for filing the IOU's report on the RFI process, and the extent to which the IOUs are subject to disallowances based on actions not taken in response to the RFI, as submitted in the report on the RFI process. SCE and CalCCA plan to submit individual opening and reply comments advancing their respective positions on this Non-Consensus Item.

IX.

<u>CONCLUSION</u>

The Co-Chairs appreciate the opportunity to submit this Final Report, and respectfully request that the Commission promptly issue a Final Decision adopting the Co-Chair Consensus

Proposals discussed herein, as summarized in the Executive Summary (Section II above) and discussed in detail in this Final Report. The Co-Chairs further request that the Commission resolve the Non-Consensus Items discussed herein in its Final Decision on the WG 3 issues.

Respectfully submitted,

JANET S. COMBS
RUSSELL A. ARCHER

/s/ Janet S. Combs
By: JANET S. COMBS

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPAI

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1524
Facsimile: (626) 302-3990
E-mail: Janet.Combs@sce.com

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY, CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

February 21, 2020

Appendix A

THIRD WORKSHOP PRESENTATION

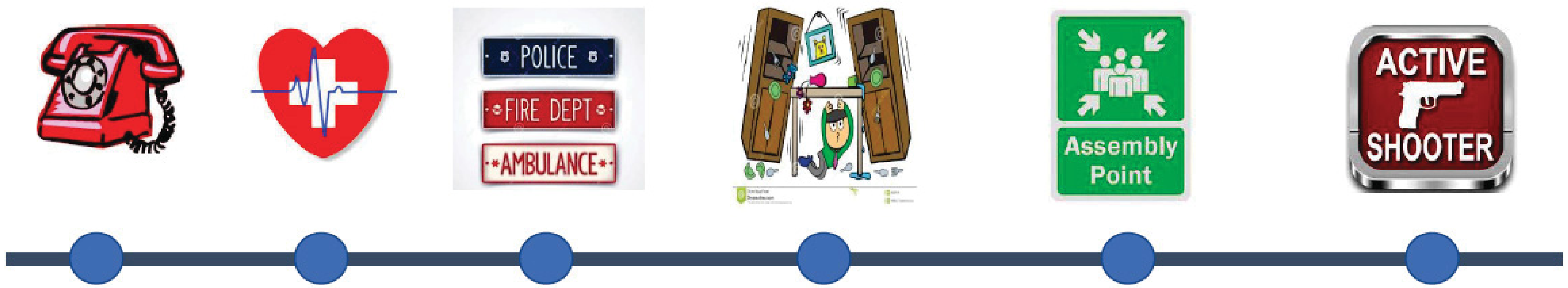
PCIA Phase 2 – Working Group Three

Portfolio Optimization and Cost Reduction, and Allocation and Auction

Voluntary Allocation & Market Offer Process for RPS and System/Flex RA

Workshop No. 3
October 17, 2019

Safety – Roles & Responsibilities



Call
911

CPR
AED
First Aid

Meet & Greet
Safety
Personnel

Duck
Cover &
Hold

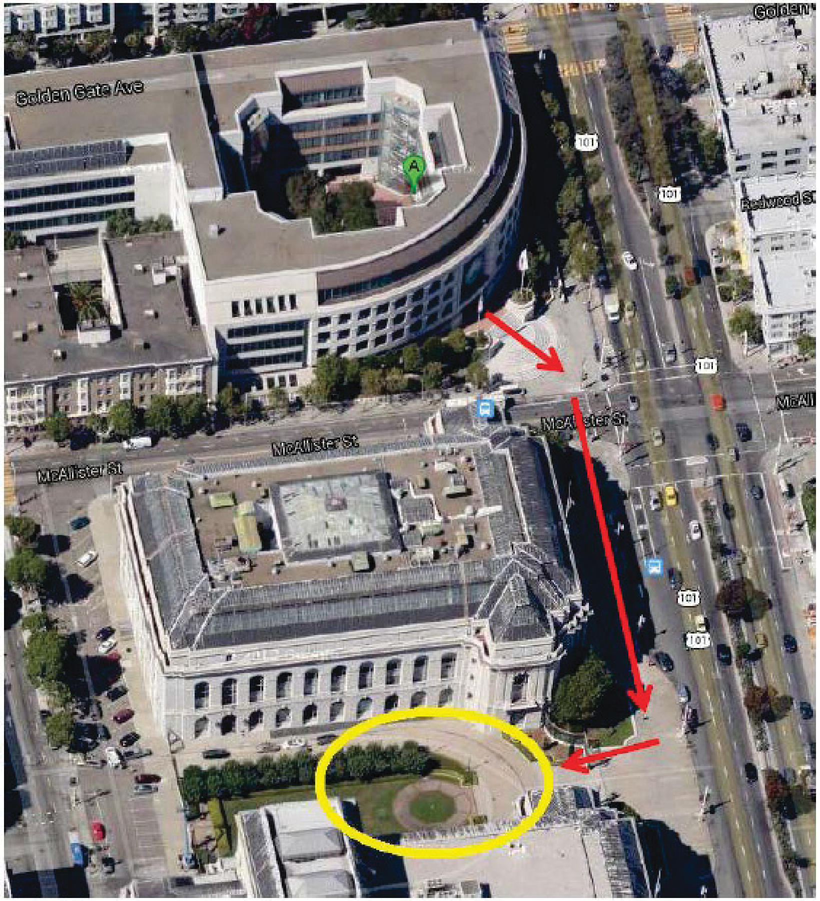
Sweep the Room

Silence Cell Phones
Get OUT
Hide OUT
Keep OUT
Take OUT

Safety – Evacuation Procedure

In the event of an emergency evacuation:

- Cross McAllister Street
- Gather in the Opera House courtyard down Van Ness, across from City Hall.



WiFi Access

Network: CPUCguest

Username: guest

Password: cpuc93019

Agenda

- Safety and Status Check
- Recap and Update of Positions from Second Workshop
- Overview of Voluntary Allocation & Market Offer Proposal
- RPS Proposal
  - Voluntary Allocation Mechanism
  - Voluntary Market Offer Mechanism
  - Long-Term RPS Sales
- System/Flex RA-Specific Mechanisms
  - Voluntary Allocation Mechanism
  - Voluntary Market Offer Mechanism
- Ratemaking Options
- Next Steps

Working Group Three – Issues to be Discussed Scoping Memo R.17-06-26

1. What are the *structures, processes, and rules governing portfolio optimization* that the Commission should consider to address excess resources in utility portfolios? How should these processes/rules be structured to be compatible with the IRP and RA program modifications proceedings?

2. What standards should the Commission adopt for *more active management of the utilities' portfolios in response to departing load* in the future to minimize further accumulation of uneconomic costs?

3. If the Commission were to *adopt standards for more active management of the utility portfolios*, how should the transition to new standards occur (e.g., timeframe, process, etc.)?

4. Should the Commission *consider new or modified shareholder responsibility or future portfolio mismanagement*, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards? Are ERRA or GRC proceedings the appropriate forums to address prudent management of portfolios?

Recap from Prior Workshops

PCIA Phase 2 - Working Group 3

Summary of Prior Workshops

- Excess Sales Framework for RA and RPS
  - Presented framework in prior workshops but did not reach consensus upon certain items including:
    - Buffer
    - Uncertainty Tranche
    - Timing of Solicitations
    - Capacity with Operational Issues
- Local RA Allocation Proposal
  - Mandatory allocation via a CAM-like mechanism, but may be traded*,**
    - Commercial supports voluntary allocation with auction of unallocated RA
  - Multi-year forward allocations track Local RA obligations
  - System and Flex RA from Local resources follows Local RA allocation
  - Allocated products receive a benchmark value of $0 in PCIA mechanism
- Voluntary GHG-Free Energy Allocation Proposal
  - Voluntary option to accept all or none of Nuclear or Non-Nuclear pools of GHG-free energy
    - Unallocated energy is re-allocated amongst LSEs accepting allocation
    - Commercial Energy supports voluntary allocation of any portion of pools, with unallocated energy being auctioned off
  - IOU continues to serve as Scheduling Coordinator for energy
  - No change to PCIA rates, as GHG-free energy receives no additional benchmark value

* SCE is neutral to trading of Local RA after an allocation, but if permitted, does not believe IOUs should be required to manage the process

** CalCCA will not support any allocation scheme that does not allow trading of allocated products

Updates to Proposals from Second Workshop

- Local RA
  - Recommend allocating on a forecasted, vintaged peak-load share basis, as determined by CPUC/CEC
    - Approach would follow existing processes, but would require submittal of vintage load forecasts and calculation of vintage peak loads*
  - Allocations will be provided pro-rata across all Local RA areas
- GHG-Free Energy
  - Recommend allocating on an annual, vintaged load-share basis based upon actual annual load and production

* Will impact CPUC, CEC, and LSEs in determining vintaged peak-load shares and tracking allocations

Voluntary Allocation and Market Offer Proposal for RPS and System/Flex RA

PCIA Phase 2 - Working Group 3

Definitions (applicable to all proposals)

- LSE – PCIA-eligible Load Serving Entities
- Allocation – the transfer of attributes and/or energy to LSEs based upon their customers' payment of PCIA rates and in proportion to their customers' vintaged annual- or peak-load shares, as applicable
- Market Offer – an annual offering, facilitated by IOUs, of unallocated products to the market in which products are sold to the highest bidders subject to a floor of $0
- GHG-Free Energy – Energy delivered from non-RPS, GHG-free resources, along with the right to claim such energy on an LSE's Power Content Label
- RPS Energy – Energy delivered from RPS resources, along with the RECs and right to claim such energy on an LSE's Power Content Label
- CAM-like mechanism – a process for allocating capacity wherein the IOU shows capacity on its supply plan, and that capacity is allocated as credits and debits to LSEs that are tracked by the CPUC in a fashion that is similar to the existing CAM allocation process

Concept for Voluntary Allocation & Market Offer Proposal for RPS and System/Flex RA

- LSEs can make an annual election to accept or decline an allocation of their vintaged share of available PCIA-eligible RPS energy & System/Flex RA
- IOU will offer to the market the unallocated RPS energy and/or System/Flex RA
- IOU will continue to manage the PCIA portfolio, performing the following functions:
  - Schedule energy into the CAISO market;
  - Show RA through a CAM-like mechanism;
  - Transfer bundled RECs to benefiting LSEs; and
  - Provide information to certify RPS energy for Power Content Label
- IOU may continue to perform portfolio optimization activities outside of Voluntary Allocation and Market Offer mechanism
  - Additional details to be discussed at the next WG 3 Workshop

Comparison of Voluntary Allocation & Market Offer vs Other Concepts

Mechanism	GAM/PMM	Excess Sales	Local RA Allocation	GHG-Free Allocation	RPS Energy Allocation & Market Offer	System / Flex RA Allocation & Market Offer
Products	RPS Energy; GHG-Free Energy; System, Flex, Local RA from RPS Resources	RPS Energy; System, Flex, Local RA	Local RA	GHG-Free Energy	RPS Energy	System and Flex RA
LSE Choice	Mandatory	N/A	Mandatory	Voluntary	Voluntary	Voluntary
IOU Retained Volume	Pro-Rata Share	Bundled Need	Peak-Load Share*	Annual Load Share*	Annual Load Share*	Peak-Load Share*
Sales from Portfolio	Gas-fired RA Energy**	RPS Energy System, Flex, and Local RA Energy**	Energy**	Energy**	Unallocated RPS Energy Energy**	Unallocated System / Flex RA Energy**
PCIA Revenue Offsets	Energy Revenue RA Sales	Energy RPS Energy System, Flex, Local RA	N/A	N/A	Unallocated RPS Sales Revenue	Unallocated System / Flex RA Sales Revenue

* Vintaged basis
** Energy is scheduled by IOU into CAISO market

Voluntary Allocation and Market Offer Mechanism for RPS

PCIA Phase 2 - Working Group 3

RPS Voluntary Allocation Structure

- RPS allocation share is based on actual, annual, vintaged load share and actual production over the course of the flow year*
  - Actual allocation amount and energy profile is subject to availability after accounting for any existing sales or other portfolio management activities by IOU
- Allocation conveys bundled RPS energy and RECs, Power Content Label credit, and Integrated Resource Plan credit
  - Allocations preserve underlying contracts' PCC status
- LSEs may elect to decline their allocation during an "open enrollment" period in 10% increments
  - IOUs will offer unallocated RPS amounts for sale to the market annually
- LSEs may sell allocated RPS energy outside of the IOU voluntary market offer process
- Allocations should be structured to preserve long-term attributes
  - SCE & Commercial: Long-term attribute should be preserved regardless of term of allocation
  - CalCCA: LSEs must accept 10+ year RPS allocations to preserve long-term attributes

* See Appendix (pg. 36-37) for illustrative, numerical example demonstrating how allocations work on a vintaged basis

RPS Voluntary Market Offer Structure

- Annually, the IOU will offer to sell all unallocated RPS energy for a term beginning in the prompt year
  - Long-term sales (i.e. for 10+ years) will be offered*,** up to a percentage cap applied to the lesser of LSE's (a) total allocation share or (b) sales election
    - RPS sales will convey long-term attributes only if sold for 10+ year terms
  - Remaining unallocated RPS energy will be sold only for prompt year
  - Sales will be structured to preserve underlying PCC status
- Voluntary market offer will be conducted once annually as follows:
  - Using pre-approved mechanisms for RFO administration, valuation, selection, and contracting;
  - Monitored by an Independent Evaluator; and
  - CAM group shall be consulted on offer selections
- Offering will be open to all market participants, including IOUs

* IOUs and Commercial Energy concerned about long-term sales. SCE and Commercial Energy would not support a cap above 25%.
** CalCCA is concerned about restrictions to long-term sales and would not support a 25% percent cap. CalCCA discussing appropriate threshold for long-term sales.

Timeline for RPS Voluntary Allocation & Market Offer

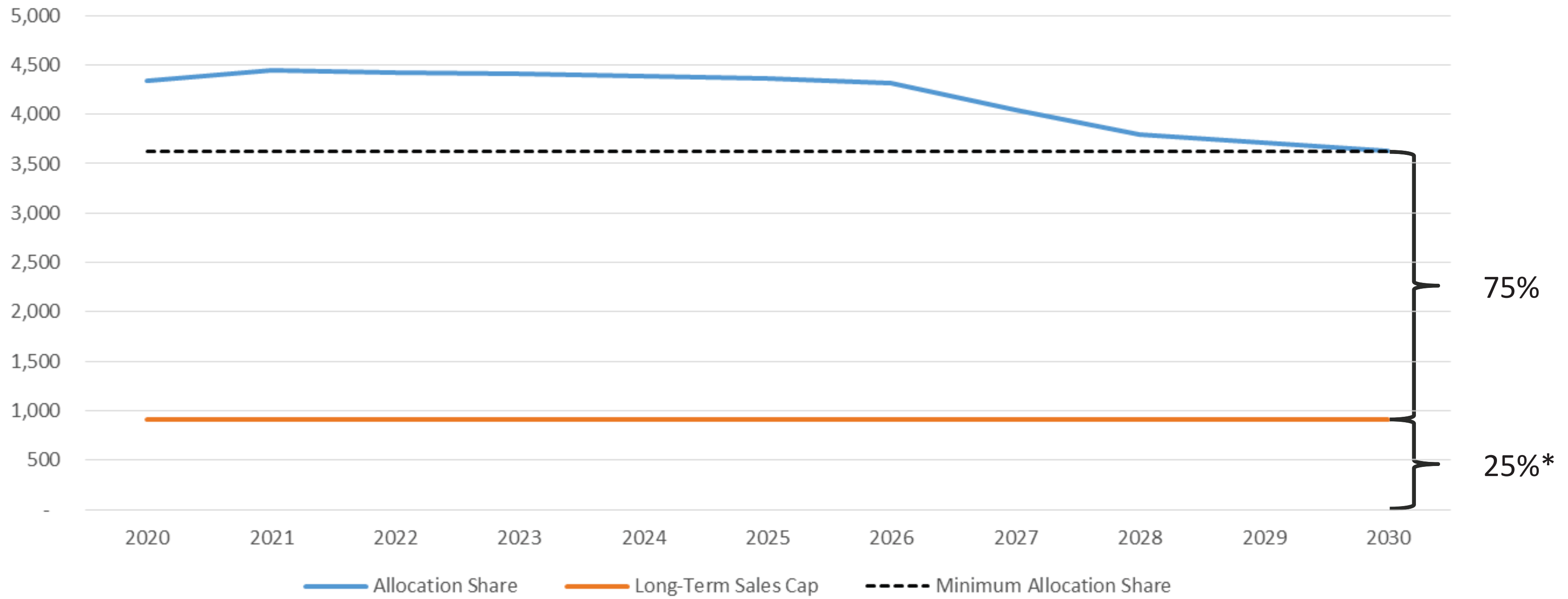
RPS Allocation & Market Offer Indicative Timeline	Proposed Date	Year
Publish RPS Generation Forecast in ERRA Forecast	Current IOU ERRA Forecast Date	N-1
LSE receives CPUC forecasted vintaged load share	Early August	
Open enrollment for LSE's allocation	Mid August	
Market Offer of unallocated RPS	August-September	
Monthly aggregated meter data published	Jan-Dec	N
Perform REC transfers for Sales	30 days following creation in WREGIS	
Determine actual LSE load shares	Q1	N+1
True up RPS generation	Q1	
Perform REC transfers for Allocations	By end of Q2	
Retire RECs for compliance	July	

RPS Sales Contract Structures

- Potential Contract Types
  - Firm – Firm quantity, no profile
  - Slice of generation – Non-firm quantity, RPS portfolio shape
  - Contingent – Balance of un-allocated RPS energy, non-firm quantity, non-firm profile
    - Mix of products need to be structured to deal with portfolio variability
- Term: One year or 10+ years, starting in prompt year
- Pricing structured as Index + REC premium
  - No price escalators over multiple years
- Buyers need to be appropriately collateralized to protect all LSEs

Long-Term RPS Sales Illustration

- IOU will sell un-allocated RPS energy long-term (10+ years) up to a capped percentage of the lesser of LSE's (a) allocation share or (b) sales election, as a long-term sale of 10+ years
- Long-term sales amounts will be based upon the LSE's forecasted minimum allocation for the term of the long-term offer



* 25% is being used here for illustrative purposes

Long-Term RPS Sales Proposal

- IOU will only enter into long-term sales if they are the most valuable offer in the offer stack
  - e.g., if IOU receives offers with prices as indicated below, then IOU selects in the following order until all capacity has cleared: D, A, C, B
    A. 1 year at $10/MWh
    B. 1 year at $8/MWh
    C. 12 years at $9/MWh
    D. 10 years $12/MWh
- If LSE's load share drops such that the capped percentage for long-term sales threshold is exceeded, no long-term sales will be performed
- Proceeds from long-term sales are co-mingled with short-term sales
  - Simplifies ratemaking by allowing all customers to pay same PCIA rates

System/Flex RA-Specific Mechanisms

System/Flex RA Voluntary Allocation Structure

- IOU will annually offer all LSEs an allocation of their vintaged share of PCIA-eligible System and Flex RA
  - RA allocation share is based on forecasted, monthly, vintaged peak-load share as determined by the CPUC*,**,***
    - Actual allocation amount is subject to availability after accounting for any existing sales or other portfolio management activities by IOU
    - System and Flex RA attributes tied to Local RA resources will follow the mandatory Local RA allocation mechanism
  - LSEs may elect to decline their allocation during an "open enrollment" period in 10% increments, rounded to nearest MW
    - Unallocated RA will be offered for sale to the market by the IOU annually
- Allocations conveyed through a CAM-like mechanism
  - Allocation is credited to LSEs and debited from IOUs by CPUC***
- LSEs may sell allocated System and Flex RA outside of the IOU voluntary market offer process

* See Appendix (pg. 45-46) for illustrative, numerical example demonstrating how allocations work on a vintaged basis

** See Appendix (pg. 44) for explanation of how the CAM-like mechanism would compare to CAM

*** Will impact CPUC, CEC, and LSEs in determining vintaged peak-load shares and tracking allocations

System/Flex RA Voluntary Market Offer Structure

- The IOU will offer to sell all unallocated System and Flex RA for the prompt year
- Voluntary market offer will be conducted once annually as follows:
  - Using pre-approved mechanisms for RFO administration, valuation, selection, and contracting;
  - Monitored by an Independent Evaluator; and
  - CAM group will be consulted on offer selections
- Offering will be open to all market participants, including IOUs

Indicative Timeline for System/Flex RA Voluntary Allocation & Market Offer

- Co-Leads still discussing timelines. A final proposal has not been agreed to.
- Existing RA timelines impose tight constraints for completing the RA Voluntary Allocation & Market Offer process

System/Flex RA Allocation & Market Offer Indicative Timeline	Status Quo Milestones	Existing Dates	Year
CPUC identifies preliminary LSE allocation shares	Coincident with preliminary RA obligations' publication	~8/10	N-1
Open enrollment for LSE's allocation	Mid August*	N/A	
CPUC identifies final LSE allocation shares	Coincident with final RA obligations' publication	~9/20	
CPUC publishes final NQC	Existing NQC publication date	~9/20	
Market Offer of unallocated RA	Mid September to early October*	N/A	
Year Ahead RA Showing	October 31	10/31	
Month Ahead RA Showings	T-45	T-45	N

- Co-Leads recommend moving RA timelines earlier in the year, which would provide more flexibility for LSEs to conduct their RA procurement

* Indicative dates are based upon today's RA and Direct Access service request timelines

System/Flex RA Contract Structures

- Contract structured as a confirm under the EEI Master Agreement
- Term: One month to one year for prompt year
- Pricing: $/kW-month
- Buyers need to be appropriately collateralized to protect all LSEs

System/Flex RA Transfer Mechanisms

- IOU will show PCIA-eligible RA capacity on annual and monthly RA supply plans
  - IOU responsible for substitution and other obligations of showing capacity
    - Any substitution capacity, CPM charges, and any CAISO costs or penalties required for, or imposed as a result of, System/Flex RA resource outages will receive full cost-recovery through the appropriate PABA account
      - **Exception:** Any costs disallowed through the IOU's ERRA proceeding would not be passed through PABA
- CPUC will notify LSEs of the debits or credits to their supply plans resulting from the CAM-like mechanism*
- LSE must show its PCIA credit on its showing to receive credit for allocation
  - LSE must show its PCIA debits corresponding to any sales of PCIA allocation

* Will impact CPUC in tracking allocations

Voluntary Allocation & Market Offer Ratemaking Mechanisms

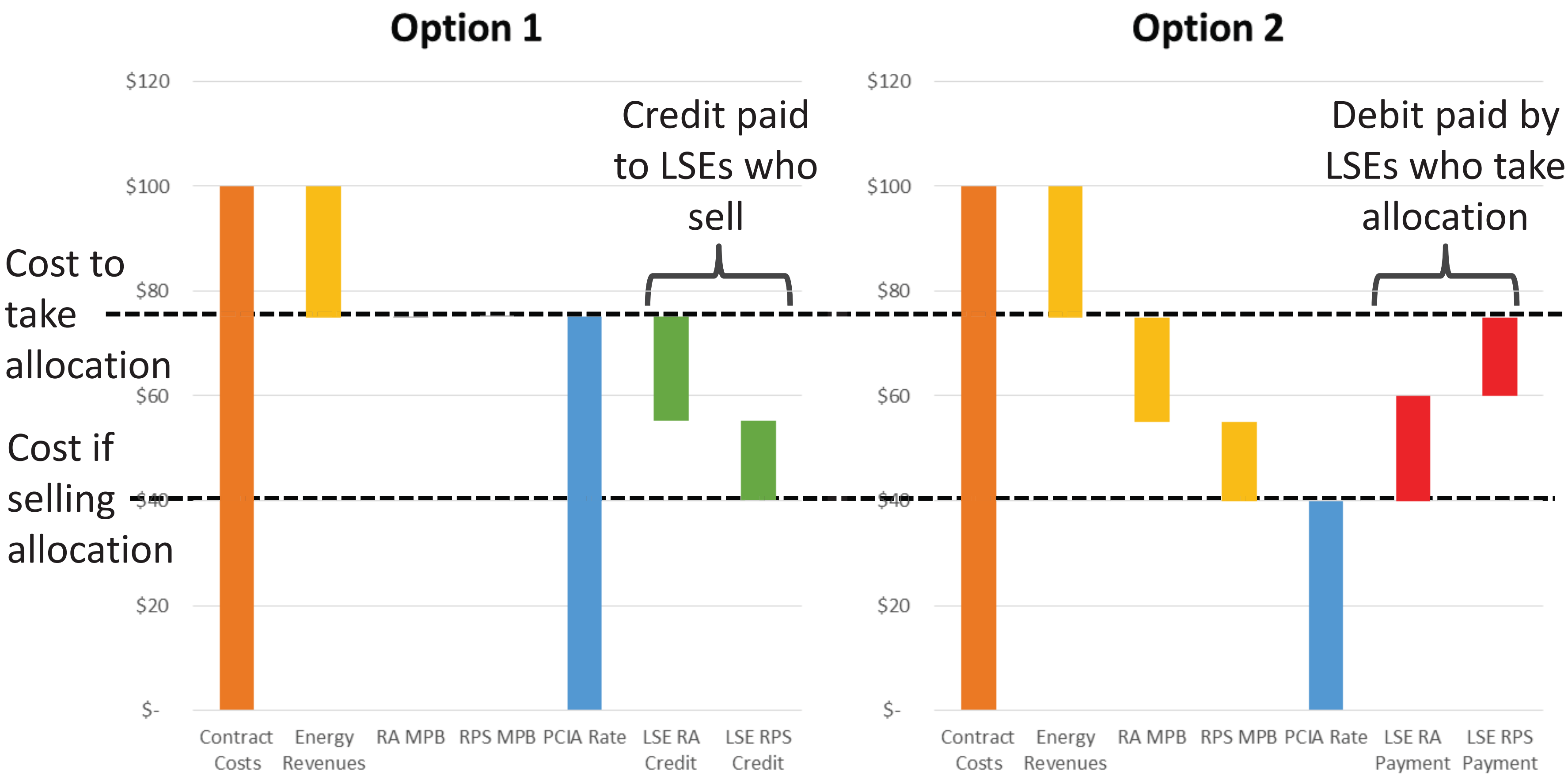
PCIA Phase 2 - Working Group 3

PCIA Ratemaking Structure

- Seek to minimize complexity of PCIA ratemaking and billing
- All customers in the same vintage pay the same PCIA rate
- Option 1: (Preferred by SCE and Commercial)
  - All customers pay full resource costs, less CAISO revenues
  - Product types available for allocation receive $0 value
  - LSEs wishing to sell products receive a direct payment from the IOU according to the LSEs' proportional share of the realized sales revenues*
- Option 2: (Preferred by CalCCA)
  - All customers pay full resource costs, less CAISO revenues, less the quantity of products in portfolio multiplied by PCIA product market price benchmark ("MPB")
  - LSEs wishing to take allocations must pay the PCIA product MPB for all products accepted as an allocation
    - An alternative to the PCIA product MPBs would be an "*auction price benchmark*" or "APB". Use of an APB makes LSEs indifferent to taking allocation or monetizing allocation through sales

* See Appendix (pg. 38-40) for illustrative example of how revenues would be re-allocated amongst LSEs choosing to sell products

PCIA Ratemaking Proposal Comparison



Assumes LSEs take allocation
Credits LSEs who sell allocation

Assumes LSEs sell allocation
Charges LSEs who take allocation

Comparison of Ratemaking Options

	Option 1	Option 2
Payment Structure	All through PCIA but eliminates MPB credit for product value	Combination of existing PCIA method with offsetting product value paid by LSE, credited to PABA
Rate Consistency	Under both options, no LSE-specific rates, reducing billing and ratemaking complexity	
Customer Rate Indifference	Under both options, customers would be indifferent whether LSEs take allocations or offer products for sale	
Exposure to Buyer Default Risks	No exposure by Allocatees	All LSEs exposed to Buyer default risks
Re-allocation of Un-Sold Products	Free re-allocation to LSEs choosing to sell*	Free re-allocation to LSEs choosing to sell. Solicitation results and un-sold products valued at $0 are incorporated into MPB
Allocatee Collateral	None	Appropriate credit backstop
Impact on PCIA rate	Higher than today, but offset by receipt of products and/or revenues	Not significantly different from today

* All RPS and RA transferred to LSEs through initial allocation or re-allocation of unsold are valued at $0

Next Steps

Feedback Requested

- Co-Leads are seeking feedback on concepts presented by 10/28
  - Please submit informal comments through CPUC Service List

- Topics the Co-Leads would ask the audience to opine upon in informal comments:
  - Voluntary Allocation & Market Offer Structure Proposal
  - RPS Process
    - RPS Long Term Sales Proposal
  - RA Process
    - Timelines
    - System/Flex RA CAM-Like Mechanism
  - Ratemaking Proposals

Next Steps

- Review informal comments received from workshop participants and refine Voluntary Allocation and Market Offer proposal
- Commence discussions on Issues 2-4:
  2. Standards for management of IOU portfolios
  3. Transition to Voluntary Allocation & Market Offer approaches
  4. Responsibility for portfolio mismanagement
- To inform positions on Issues 2-4, Co-Chairs ask that Parties submit any proposals through informal comments to the CPUC Service List by 11/4
- Upcoming deliverables:
  - Fourth WG3 Workshop expected early- to mid-December, 2019
    - Refinement of Voluntary Allocation and Market Offer process
    - Issues 2-4
  - Final Report due January 30, 2020

Appendix

PCIA Phase 2 - Working Group 3

SCE Proposed Process for Regulatory Approval of Voluntary Market Offer Contracts

- IOU updates Bundled Procurement Plan and RPS Procurement Plan to reflect that it will be conducting annual auctions on behalf of LSEs
  - Permits authority for IOU to enter into long-term sales of PCIA-eligible RPS
- IOU files an Advice Letter requesting pre-approval of:
  - RPS confirms to be used in the auctions
  - Proposed auction process, valuation methods, and offer selection mechanisms
- IOU adheres to established processes as follows:
  - Consults with CAM group prior to (i) auction launch and (ii) final offer selection and contract execution
  - Files executed contracts in appropriate filing:
    - Annual ERRA testimony; *or*
    - Quarterly Compliance Report; *or*
    - A single Advice Letter documenting the auction results
  - Review of IOU actions constrained to whether IOU followed process appropriately. Contract prices are not subject to review, as the auction seeks to clear all products at any price greater than $0.

RPS-Specific Mechanisms

PCIA Phase 2 - Working Group 3

RPS Voluntary Allocation Example

1. Determine LSE annual loads, peak loads, and vintages

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020

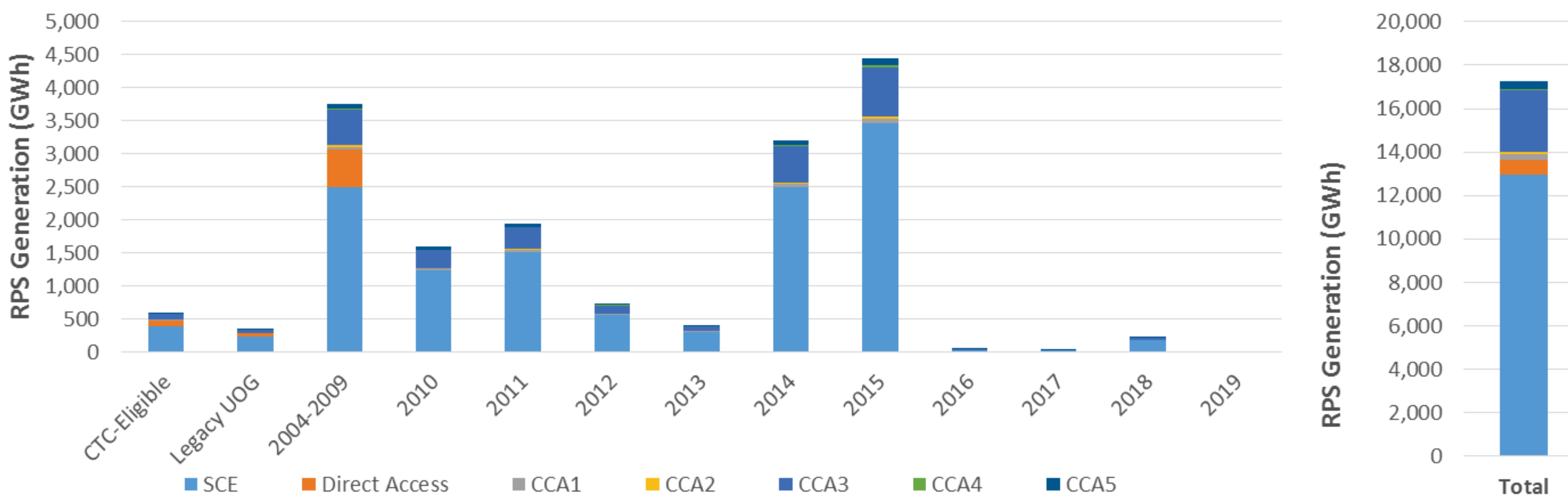
2. Determine vintaged LSE load shares

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	N/A	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000
Direct Access	2009	12,500	12,500	12,500										
CCA1	2015	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000				
CCA2	2017	500	500	500	500	500	500	500	500	500	500	500		
CCA3	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	
CCA4	2018	400	400	400	400	400	400	400	400	400	400	400	400	
CCA5	2020	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Total Load (GWh)		83,000	83,000	83,000	70,500	70,500	70,500	70,500	70,500	70,500	69,500	69,500	69,000	56,600

RPS Voluntary Allocation Example (continued)

3. Determine PCIA-eligible products by vintage and allocate according to load share

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Allocation	% of Total RPS
Total RPS (GWh) *		592	345	3,761	1,589	1,940	728	392	3,206	4,442	42	27	226	0	17,290	100%
SCE	N/A	392	229	2,492	1,240	1,513	568	306	2,501	3,465	33	21	180	0	12,941	75%
Direct Access	2009	89	52	566	0	0	0	0	0	0	0	0	0	0	708	4%
CCA1	2015	7	4	45	23	28	10	6	45	63	0	0	0	0	231	1%
CCA2	2017	4	2	23	11	14	5	3	23	32	0	0	0	0	116	1%
CCA3	2018	86	50	544	270	330	124	67	546	756	7	5	39	0	2,824	16%
CCA4	2018	3	2	18	9	11	4	2	18	25	0	0	1	0	94	1%
CCA5	2020	11	7	73	36	44	17	9	73	101	1	1	5	0	376	2%



* Source: SCE's public ERRA 2020 Forecast

Proposed Voluntary Auction Revenue Allocation Mechanism

1. Determine PCIA-eligible products to be allocated to each LSE (Table 3 of Allocation)

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Allocation
Total RPS (GWh)		592	345	3,761	1,589	1,940	728	392	3,206	4,442	42	27	226	-	17,290
SCE	N/A	392	229	2,492	1,240	1,513	568	306	2,501	3,465	33	21	180	0	12,941
Direct Access	2009	89	52	566	0	0	0	0	0	0	0	0	0	0	708
CCA1	2015	7	4	45	23	28	10	6	45	63	0	0	0	0	231
CCA2	2017	4	2	23	11	14	5	3	23	32	0	0	0	0	116
CCA3	2018	86	50	544	270	330	124	67	546	756	7	5	39	0	2,824
CCA4	2018	3	2	18	9	11	4	2	18	25	0	0	1	0	94
CCA5	2020	11	7	73	36	44	17	9	73	101	1	1	5	0	376

2. Evaluate impact of each LSE's sales elections and pool products for sale. Determine maximum to be sold for prompt year and over 10+ year terms

Sales Elections	% Sold	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Sales	Max Long-Term Sales*
SCE	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Access	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA1	100%	7	4	45	23	28	10	6	45	63	0	0	0	0	231	58
CCA2	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA3	50%	43	25	272	135	165	62	33	273	378	4	2	20	0	1412	353
CCA4	100%	3	2	18	9	11	4	2	18	25	0	0	1	0	94	24
CCA5	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total (GWh)		53	31	335	167	204	76	41	337	466	4	2	21	0	**1737**	**434**

* Assumes 25% long-term sales threshold

Proposed Voluntary Auction Revenue Allocation Mechanism (continued)

3. Accept bids to purchase products in Market Offer process

Bid #	Prices	Quantities	Term
Bid 1	$10	400	1
Bid 2	$12	500	10
Bid 3	$8	200	1
Bid 4	$19	50	1
Bid 5	$15	300	10
Bid 6	$14	200	1
Bid 7	$6	1000	1
Bid 8	$1	1500	10
Bid 9	$9	700	1
Bid 10	$7	600	1

4. Order bids by price and accept bids until all quantities have been sold

Selection Order	Bid #	Prices	Quantities (GWh)	Term	Cumulative Long Term	Adjusted LT Quantity	Cumulative Quantity	Adjusted Quantity	Revenue/Yr
Contract 1	Bid 4	$19	50	1	0	0	50	50	$950,000
Contract 2	Bid 5	$15	300	10	300	300	350	300	$4,500,000
Contract 3	Bid 6	$14	200	1	300	0	550	200	$2,800,000
Contract 4	Bid 2	$12	500	10	434	134	684	134	$1,610,769
Contract 5	Bid 1	$10	400	1	434	0	1084	400	$4,000,000
Contract 6	Bid 9	$9	700	1	434	0	1737	653	$5,874,231
Contract 7	Bid 3	$8	200	1	434	0	1737	0	$0
Contract 8	Bid 10	$7	600	1	434	0	1737	0	$0
Contract 9	Bid 7	$6	1000	1	434	0	1737	0	$0
Contract 10	Bid 8	$1	1500	10	434	0	1737	0	$0
Total									$19,735,000

Proposed Voluntary Auction Revenue Allocation Mechanism (continued)

5. Allocate revenues pro-rata amongst LSEs based upon their contribution to pool of products to be sold (from Table 2)

Revenue Allocation	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Sales
Total RPS Sales (GWh)	53	31	335	167	204	76	41	337	466	4	2	21	0	1737
Total Revenue Allocation	$599,697	$349,486	$3,809,899	$1,895,060	$2,313,667	$868,221	$467,504	$3,823,514	$5,297,582	$43,944	$28,250	$238,175	$0	$19,735,000
SCE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Direct Access	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CCA1	$81,040	$47,228	$514,851	$256,089	$312,658	$117,327	$63,176	$516,691	$715,889	$0	$0	$0	$0	$2,624,950
CCA2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CCA3	$486,241	$283,367	$3,089,108	$1,536,535	$1,875,946	$703,963	$379,057	$3,100,146	$4,295,337	$41,198	$26,484	$223,289	$0	$16,040,671
CCA4	$32,416	$18,891	$205,941	$102,436	$125,063	$46,931	$25,270	$206,676	$286,356	$2,747	$1,766	$14,886	$0	$1,069,378
CCA5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

RPS Transfer Mechanisms

- Transfer of RECs from IOU WREGIS account to Allocatee's WREGIS account by Q2 following flow year, with sufficient time for LSEs to meet compliance obligations
  - RECs will be sourced from any similar PCIA-eligible resources
    - e.g., long-term PCC1
- Transfer of RECs to Buyer's WREGIS account will occur on a monthly basis within 30 days of RECs' creation by WREGIS
- Transfer of GHG-free credit will be effectuated through reporting of debit from IOU and credit to benefiting LSE's Power Content Label through a filing with the CEC*
  - Filed in Q2 following flow year
- IRP
  - Intended for LSEs to receive credit for their eligible allocation shares, less any long-term Market Offer sales, from the vintaged PCIA portfolio in the IRP process
    - Any sales performed by any LSE of its allocated share, or by IOU through portfolio optimization, are treated in accordance with existing IRP rules and requirements

* Subject to CEC regulatory reporting requirements

RPS Power Content Label Forecasting

- IOU will provide the following forecasts of aggregated RPS production by vintaged pool*:
  - Resource IDs for all resources;
  - The aggregated, total year-ahead ERRA forecast;
  - An aggregated, year-ahead forecast of the total production for each of the 12 months;
  - Quarterly updates for remaining balance of year of the monthly total, aggregated production; and
  - IOU will provide past three years of historical, aggregated, hourly production data
- Information must be aggregated to preserve confidentiality
  - Inability to aggregate may prevent provision of forecast or meter data for year N-1

*IOU bears no responsibility to benefiting LSEs for accuracy of forecasts provided

System/Flex RA-Specific Mechanisms

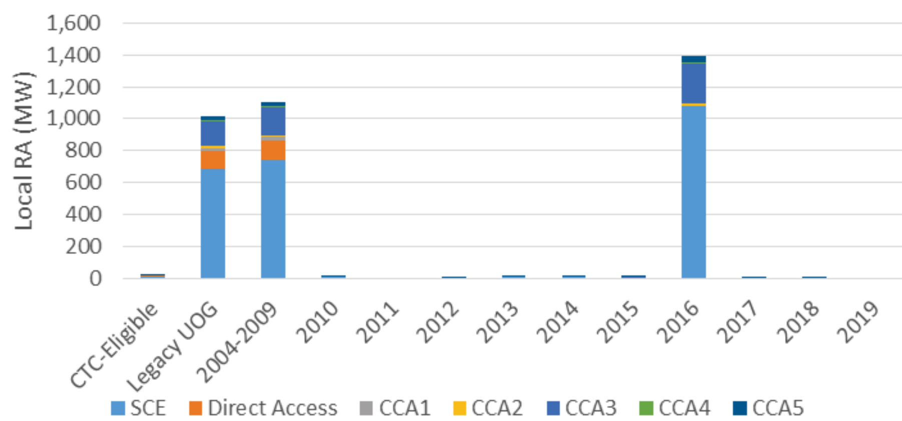
System/Flex RA Voluntary Allocation: "CAM-like" Mechanism

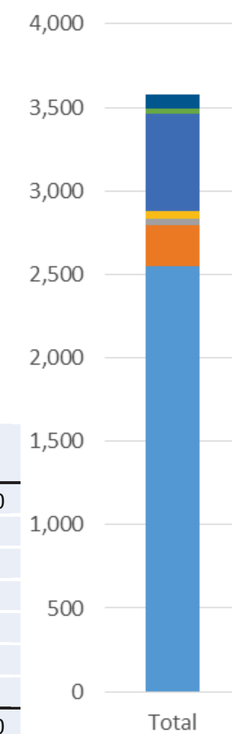
- IOU will show all PCIA-eligible RA resources on its supply plan and for each RA compliance filing
- Annually in the Fall, CPUC will determine appropriate share of each vintage's System and Flex RA positions to be allocated to each LSE for each month of the prompt year
- Annually, concurrently with the publication of the final RA compliance requirements, CPUC will:
  - Issue a letter to IOU indicating quantities of RA debited from IOU positions for allocation purposes; and
  - Issue a letter to each benefiting LSE indicating quantities of RA credited towards LSE's positions
- Each LSE will reflect the PCIA credit/debit within its annual CAISO RA showing
- Actual quantities debited and credited may vary year-over-year, subject to changes in load share, IOU contract management activities, NQC adjustments, etc.
  - Contract management activities are governed through ERRA and AB57, with PRG consultation (as appropriate)
- IOU will maintain responsibility for outages, substitution capacity, penalties, etc.
  - Costs incurred passed through PCIA mechanism, except for any costs disallowed through the IOU's ERRA proceeding

For more information on CAM process, refer to: https://www.cpuc.ca.gov/General.aspx?id=6311
See 2019 Final RA Guide and CAM Allocation links

Local RA Voluntary Allocation Example

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020





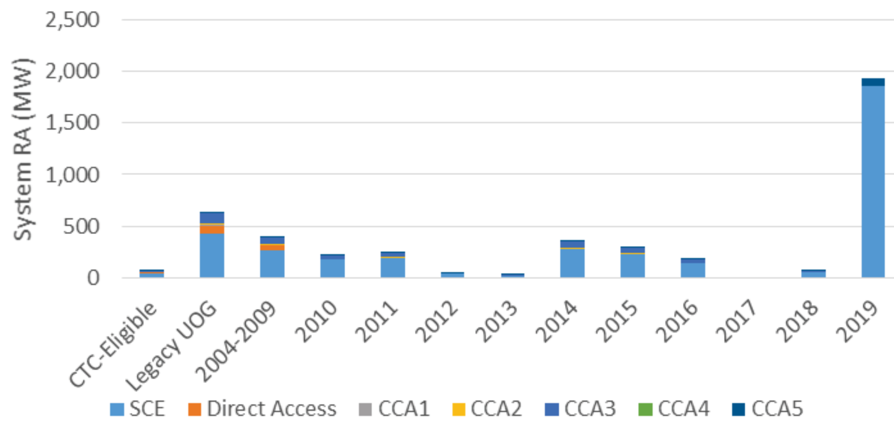
LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	2019	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Direct Access	2009	2,200	2,200	2,200										
CCA1	2015	360	360	360	360	360	360	360	360	360				
CCA2	2017	225	225	225	225	225	225	225	225	225	225	225		
CCA3	2018	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	
CCA4	2018	140	140	140	140	140	140	140	140	140	140	140	140	
CCA5	2020	450	450	450	450	450	450	450	450	450	450	450	450	450
Total Peak-Load (MW)		19,375	19,375	19,375	17,175	17,175	17,175	17,175	17,175	17,175	16,815	16,815	16,590	13,450

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total Local RA Allocation	% of Total Local RA
Total Local RA* (MW)		20	1,018	1,102	10	0	3	9	11	8	1,393	1	6	0	3,579	100%
SCE	2019	13	683	739	8	0	2	7	8	6	1,077	1	4	0	2,548	71%
Direct Access	2009	2	116	125	0	0	0	0	0	0	0	0	0	0	243	7%
CCA1	2015	0	19	20	0	0	0	0	0	0	0	0	0	0	41	1%
CCA2	2017	0	12	13	0	0	0	0	0	0	19	0	0	0	44	1%
CCA3	2018	3	158	171	2	0	0	2	2	1	249	0	1	0	588	16%
CCA4	2018	0	7	8	0	0	0	0	0	0	12	0	0	0	27	1%
CCA5	2020	0	24	26	0	0	0	0	0	0	37	0	0	0	88	2%

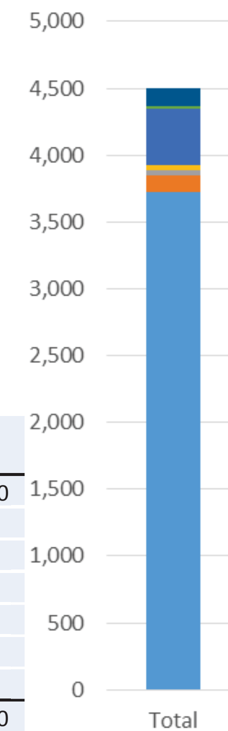
* Source: SCE's public ERRA 2020 Forecast

System RA Voluntary Allocation Example

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020



LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	2019	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Direct Access	2009	2,200	2,200	2,200										
CCA1	2015	360	360	360	360	360	360	360	360	360				
CCA2	2017	225	225	225	225	225	225	225	225	225	225	225		
CCA3	2018	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	
CCA4	2018	140	140	140	140	140	140	140	140	140	140	140	140	
CCA5	2020	450	450	450	450	450	450	450	450	450	450	450	450	450
Total Peak-Load (MW)		19,375	19,375	19,375	17,175	17,175	17,175	17,175	17,175	17,175	16,815	16,815	16,590	13,450



LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total System RA Allocation	% of Total System RA
Total System RA* (MW)		64	643	399	227	250	47	27	360	297	184	0	73	1,928	4,499	100%
SCE	2019	43	432	268	172	189	36	21	272	225	142	0	57	1,863	3,720	83%
Direct Access	2009	7	73	45	0	0	0	0	0	0	0	0	0	0	126	3%
CCA1	2015	1	12	7	5	5	1	1	8	6	0	0	0	0	46	1%
CCA2	2017	1	7	5	3	3	1	0	5	4	2	0	0	0	31	1%
CCA3	2018	10	100	62	40	44	8	5	63	52	33	0	13	0	428	10%
CCA4	2018	0	5	3	2	2	0	0	3	2	2	0	1	0	20	0%
CCA5	2020	1	15	9	6	7	1	1	9	8	5	0	2	65	129	3%

* Source: SCE's public ERRA 2020 Forecast

Illustrative Voluntary Auction Valuation Mechanism

1. Determine Sales Quantities

Amounts for Sale	Month	Quantity (MW)
July	7	300
August	8	350
September	9	250

2. Receive Bid Prices and Quantities

Offer	Term	Month	Price ($/kW-mo)	Quantity (MW)
1	July	7	$4.00	100
2	July	7	$6.00	50
3	July	7	$5.50	300
4	August	8	$2.50	200
5	August	8	$4.25	100
6	August	8	$5.10	50
7	September	9	$3.50	150
8	September	9	$4.50	200
9	September	9	$3.25	50
10	Q3	7	$4.75	200
10	Q3	8	$4.75	200
10	Q3	9	$4.75	200

Illustrative Voluntary Auction Valuation Mechanism (continued)

3. Rank Bids by Price

Offer	Term	Month	Price ($/kW-mo)	Quantity (MW)
2	July	7	$6.00	50
3	July	7	$5.50	250
10	Q3	7	$4.75	200
1	July	7	$4.00	100
6	August	8	$5.10	50
10	Q3	8	$4.75	200
5	August	8	$4.25	100
4	August	8	$2.50	200
10	Q3	9	$4.75	200
8	September	9	$4.50	200
7	September	9	$3.50	150
9	September	9	$3.25	50

4. Select Bids up to Quantity Available, While Maximizing Revenues

Selected Offers	Term	Month	Price ($/kW-mo)	Quantity (MW)	Revenue ($000)
2	July	7	$6.00	50	$300.00
3	July	7	$5.50	50	$275.00
10	Q3	7	$4.75	200	$950.00
6	August	8	$5.10	50	$255.00
10	Q3	8	$4.75	200	$950.00
5	August	8	$4.25	100	$425.00
10	Q3	9	$4.75	200	$950.00
8	September	9	$4.50	50	$225.00
Total					**$4,330.00**

Appendix B

INFORMAL COMMENTS TO THIRD WORKSHOP PRESENTATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS INFORMAL COMMENTS ON PCIA WORKING GROUP 3 MEETING #3

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
Telephone: (510) 778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

28 October 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS PCIA WORKING GROUP 3 WORKSHOP #3

The Alliance for Retail Energy Markets ("AReM") appreciates the opportunity to provide these informal comments on topics introduced in Workshop #3 of Working Group #3 ("WG3"), conducted on 17 October 2019 in San Francisco, California. AReM's comments below are focused on the Local RA allocation proposal, proposed options for PCIA Ratemaking, and remaining clarifications needed.

AReM understands that the important work of determining how to get the IOU resource portfolios in line with the amount of load they are serving is intended to be addressed in future WG3 meetings and believes that is the most important work that this WG should be addressing. The efforts to construct voluntary resource allocations to LSEs paying a fair market value for them (a model very similar to the IOU Portfolio Allocation Mechanism introduced earlier in this proceeding and rejected) followed by an auction of unallocated resources is unduly complicated and inferior to a simpler mechanism that would solely auction off excess resources. That said, the revision presented in Workshop 3 for allocations based on vintage peak-load share instead of PCIA contribution levels is an improvement over previous proposals, but AReM continues to believe that this WG has so far missed the mark by focusing on short-term sales and allocations instead of focusing on approaches that will result in getting IOU resources in line with the amount of load they are serving and expected to serve over the long term.

If the short-term proposals are nevertheless to be implemented, AReM urges that the following issues be addressed.

Local RA Allocation Proposal

As stated in previous comments, AReM considers the proposed allocation proposal to be inferior to a mechanism that would auction off the excess Local RA to willing buyers. As an alternative to this uncompetitive, non-market based proposal, the IOUs should continue to make Local RA available to all entities through an auction first, until longer term divestiture by the IOUs of their excess supply can be finalized. While the WG3 leads state that the reason for the allocation is to get around issues related to the buffer and uncertainty tranches, there is no reason that the same amount of PCIA-eligible resources cannot be sold in an auction instead of through an allocation process.

While all other resource attributes (System/Flex RA, RPS, and GHG-Free resources) are being allocated on a voluntary basis, WG3 continues to propose that Local RA allocation be mandatory. If an allocation process occurs, AReM does not believe that there is a need to treat Local RA differently from other resource allocations and asks the WG3 leads develop an approach where Local RA will also be allocated on a voluntary basis only. In addition, mandatory allocations run counter to Commission direction for what the Working Groups should consider[1], as outlined by DACC in their comments of 9 August.

[1] D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at p. 96.

Under the WG3 proposal, entities not needing their full allocation could sell to others, but that approach just exchanges one problem for another. Much like the IOUs today, there is no guarantee that those entities will sell any excess they have, will have time to sell any excess they have given when the allocation occurs, that those entities will not keep the excess as a "buffer" or for "uncertainty", or that those entities will not use allocated Local for System or Flex RA needs.

In addition, many LSEs may not need their allocation, especially in areas with increasing levels of CAM allocations. For example, all non-IOU LSEs are seeing considerably lower LA Basin Local RA requirements beginning in 2022 due to new CAM allocations. A mandatory allocation could then force non-IOU LSEs to take and pay through the PCIA for resources that they do not need.

Another major issue with any RA allocation followed up by an auction is the timing of the entire process. As outlined in the workshop (slide 23), timing of the yearly RA process is very tight; in the absence of modifications of the RA timelines, the process may become unworkable. For these resources to be tradable and for LSEs to optimize their own portfolios, the allocated resources should be provided to LSEs as soon as yearly obligations are finalized so that they can be used by the end of the year ahead compliance period. This tightness is yet another reason why an auction process without allocation is recommended.

Finally, the WG leads need to address how these allocations will work in an environment with a residual or full central buyer for Local RA. While it is unclear at this stage the type of central buyer that will be implemented by the Commission for Local RA, consideration should still be made for how the proposals will be adapted and integrated under each of these central buyer options. If a central buyer will lead to material changes to the allocation approach being considered by this WG3, that would be useful information for stakeholders to consider.

PCIA Ratemaking

The workshop presented two options for changes to PCIA Ratemaking to support the proposals developed by WG3. Option 1 keeps the PCIA approach generally the same as today, with credits given to individual LSEs which choose to have the IOU sell their allocation in an auction. Option 2 decreases the PCIA costs by the RA and RPS Market Price Benchmark ("MPB") for resources available for allocation, with LSEs then paying the IOU for the RA and RPS attributes of the resources that it accepts in the allocation.

AReM prefers Option 2. First, Option 2 appropriately follows cost causation principles. Under this option, entities that accept their allocation will have specific costs imposed on them for this allocation, as opposed to Option 1 where costs are imposed on all LSEs through the PCIA. Second, Option 2 allows LSEs to more easily compare options to meet their procurement requirements. Under Option 2, LSEs will know what their costs will be if they accept their allocation (either the MPB or an Auction Price Benchmark ("APB")) and can compare this cost with other options in the market to meet their needs. This is not the case in Option 1 where the value that LSEs will be credited with will not be known until the auction is held later. This uncertainty for the value of their allocation makes it more difficult to compare versus other market offers.

AReM members are focused on reducing their PCIA exposure, having more control over our procurement, and moving resources out of IOU control. Option 2 for assessment of future PCIA values and assigning costs best helps to meet these goals relative to Option 1.

Long-Term Sales Clarifications Required

In review of the recent WG3 documents, AReM requests clarification on two topics related to long-term RPS sales:

- **Long-term Sales Cap:** It is unclear what is meant when the WG3 leads state that the cap will be "applied to the lesser of LSE's (a) total allocation share or (b) sales election" and how these two items differ. Also, it is unclear how a proposed 25% cap was developed, if there were any analytics around the basis for this number, and what other options were considered.
- **Alignment with RPS Rulemaking:** The WG3 leads identify 2 options for long-term allocations: 1) long-term attributes preserved regardless of term of allocation and 2) 10 year+ allocations to preserve long-term attributes. Option 1 runs counter to current RPS rules (and potentially the intent of SB 100 legislation) that contracts must be for 10 years or longer to count for long-term RPS obligations, so it is unclear how the SCE and Commercial Energy proposal will work in light of these restrictions. Option 2 appears to be the only option that aligns with current RPS compliance rulemaking. The RPS long-term contracting rules should not be changed now for the benefit of entities not prepared to undertake long-term contracting risk.

Remaining Concerns

AReM believes that this WG has missed an opportunity to focus on approaches that will result in getting IOU resources in line with the amount of load they are serving and expected to serve over the long term, rather than focusing on short-term sales and allocations. While the WG3 leads have stated that these issues are to be considered before Workshop 4, this leaves little time to review and provide input before the release of the Final Report on January 30, 2020.

Other items remain outstanding that need to be addressed are the following:

- **Tracking:** How will these credits be tracked to assure attributes are retired and not double counted? Without a robust accounting mechanism for these credits, the proposal should not move forward.
- **Acceptance by Regulatory Agencies:** Both the CEC as part of accounting for the Power Content Label ("PCL") and the Commission's IRP GHG Net Short do not credit RECs not associated with physical power delivery in these programs; each program wants to see information on the generation source of the physical power purchased by each LSE. Similarly, it is unclear to AReM if these GHG-Free attributes that will be allocated, with no physical power or contracts changing hands, will be accepted by either the CEC as part of the PCL or the Commission as part of the IRP. Affirmation should be presented from both agencies, along with information as to whether any new rulemaking will be required to allow this new attribute to be included in each program.

AReM asks that these issues be addressed and resolved before the final report.

Respectfully submitted,

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
510.778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

28 October 2019

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

**DIRECT ACCESS CUSTOMER COALITION INFORMAL COMMENTS
ON WORKING GROUP #3 THIRD WORKSHOP**

Mark Fulmer
MRW & ASSOCIATES
1736 Franklin St. Suite 700
Oakland, CA 94612
Telephone: (510) 834-1999
mef@mrwassoc.com

Consultant to
DIRECT ACCESS CUSTOMER COALITION

Daniel W. Douglass
DOUGLASS & LIDDELL
4766 Park Granada, Suite 209
Calabasas, California 91302
Telephone: (818) 961-3001
douglass@energyattorney.com

Attorney for the
DIRECT ACCESS CUSTOMER COALITION

October 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

DIRECT ACCESS CUSTOMER COALITION INFORMAL COMMENTS ON WORKING GROUP #3 THIRD WORKSHOP

The Direct Access Customer Coalition[1] ("DACC") offers herein its informal comments on topics introduced in Meeting #3 of Working Group #3 ("WG3") that was held on October 17, 2019 at the Commission Auditorium.

DACC appreciates the efforts undertaken by Southern California Edison, California Community Choice Association and Commercial Energy to develop the materials and discussion topics considered at the workshop. DACC's comments on the last workshop noted its grave concerns with the application of a cost allocation mechanism ("CAM")-like default allocation of resource adequacy ("RA") and renewable portfolio standard ("RPS") products and costs to all customers. DACC is grateful to see that the Working Group leaders have, for the most part, moved away from these mandatory allocations of costs and attributes.

However, DACC notes that the direct allocation of local RA costs and attributes appears to persist. DACC continues to maintain that any excess local RA should be made available to other load-serving entities and not forced upon their customers.

[1] DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access ("DA") for all or a portion of their electrical energy requirements. In the aggregate, DACC member companies represent over 1,900 MW of demand that is met by both DA and bundled utility service and about 11,500 GWH of statewide annual usage.

DACC members strongly prefer interacting with their electric service providers ("ESPs") for all products and services. As such, DACC strongly prefers cost allocation "Option 2," wherein only the stranded cost of the IOUs' portfolios are in the PCIA, including both RA and RPS.

If a DA customer's ESP finds it preferable to accept an allocation of RA or RPS products at the IOU's cost, then it should be able to do so, and if not, then it should be able to decline this option. Option 1, with the automatic allocation of products to a DA customer's ESP adds a layer of opacity to the DA customer's ESP relationship and has the potential to greatly increase the PCIA. DACC opposes both of these outcomes.

Respectfully submitted,

Mark Fulmer
MRW & ASSOCIATES

Consultant to
DIRECT ACCESS CUSTOMER COALITION

Daniel W. Douglass
DOUGLASS & LIDDELL

Attorney for the
DIRECT ACCESS CUSTOMER COALITION

October 28, 2019.

INFORMAL COMMENTS OF THE AMERICAN WIND ENERGY ASSOCIATION OF CALIFORNIA AND THE LARGE-SCALE SOLAR ASSOCIATION ON PCIA WORKING GROUP 3 OCTOBER 17th WORKSHOP

October 28, 2019

AWEA-California and LSA appreciate this opportunity to provide informal comments on the working group 3 proposals for an allocation mechanism within the PCIA framework. AWEA-California and LSA represent much of the utility-scale renewable energy industry in California, and our members hold many of the existing contracts with the IOUs for RPS-eligible energy and capacity. Members of both organizations strive to develop utility scale renewable energy projects that provide the most value to ratepayers. AWEA-California and LSA support the State's efforts to develop a diverse portfolio of clean capacity that addresses RPS needs and best contributes to resource adequacy needs.

In light of the rapid growth of CCAs, there is clearly a need to balance supply and demand. AWEA-California and LSA are supportive of changes to the PCIA that would ensure that the CCAs and ESPs that are paying the PCIA receive product value from the IOUs portfolio. If properly structured, a PCIA allocation mechanism will provide needed certainty to the market and will provide greater stability as the state seeks to build new clean capacity that achieves IRP, RPS, Resource Adequacy requirements.

AWEA-California and LSA are generally supportive of the party proposals to develop new innovative mechanisms for allocating different product types. In particular, it is our understanding that all of the proposals discussed at the October 17th workshop would account for sellers' rights by not requiring modification or assignment of existing PPAs. The need to account for sellers' rights was among the guiding principles established in the first phase of this proceeding. We believe the concept of having the IOUs remain financially responsible and continue to serve as the scheduling coordinator is a reasonable way to adhere to the Commission's guiding principles for this proceeding.

We also appreciate the parties' efforts to develop proposals that would account for the complexities of the various regulatory programs affecting buyers. One of the issues debated during the October 17th workshop was the question of whether long term contracts retain their "long term" status when a CCA or ESP enters into a new contract to receive a slice of the IOU's portfolio. At the CCA/ESP's option, this "slice" may include PCC-1 RECs, presumably generated from a long-term contract between the IOU and the seller. The question is whether a one year contract between the CCA/ESP and the IOU to receive that slice will satisfy the long term contracting requirements applicable to that CCA or ESP.

The long term RPS contracting requirement is codified in Section 399.13(b) of the Public Utilities Code:

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

The statute clearly applies to individual load-serving entities and directs the Commission to evaluate whether the entity submitting an RPS compliance plan has entered into a contract that is 10 years or more. A proposal to transfer RECs through a one-year contract between a CCA/ESP and the IOU would not comport with Section 399.13(b) because the contract the CCA/ESP points to in its RPS compliance filing is only one year. Under the proposal discussed at the October 17th workshop, the CCA/ESP would not have privity of contract with the parties of any contracts in the IOUs' portfolios. The CCA/ESPs would only have privity of contract with the IOUs and that contract would not meet the requirements of Section 399.13(b).

In addition, the October 17th workshop proposal for a one-year RPS contract structure would also be inconsistent with the Commission decisions implementing Section 399.13(b). For example, in D.17-06-026, the CPUC evaluated the circumstances under which certain variations of contract structures comport with Section 399.13(b). It is important to note that in this and other decisions implementing the long-term contracting requirement, the Commission's focus is on the contracting practices of the individual LSE submitting the RPS compliance plan, not the upstream contracts.

D.17-06-026 specifically contemplates contract structures analogous to those discussed at the October 17th workshop – i.e., "repackaged contracts". A repackaged contract is one in which "a long-term contract for a large volume of generation is divided into smaller pieces, with the pieces being sold to several different parties."[1] The Commission concludes that "[s]uch contracts may be used to meet the LT requirement, so long as they are truly long term, i.e., the retail seller's contract for its repackaged share of the generation has a duration of at least 10 years."[2] In the

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[1] D.17-06-026 at p. 21.
[2] *Id.*

context of the PCIA, the rules in D.17-06-026 would apply to a CCA or ESP taking a repackaged slice of the IOUs RPS portfolio. A CCA or ESP taking a slice of RPS energy/RECs would only be able to claim compliance with the long term contracting requirement if its contract with the IOU for that slice is at least ten years. Thus, in order to move forward with a proposal for a one year slice that satisfies the long term contracting requirement, the parties would need to pursue statutory amendments to Section 399.13(b) and the Commission would need to re-interpret that amended statute.

For these reasons, the parties should consider enabling PCIA allocation contract structures that adhere to existing statutory language of Section 399.13(b). AWEA-California and LSA look forward to continuing to participate in this process and support the parties' efforts to balance supply and demand for all energy, capacity and environmental products through a PCIA allocation mechanism.

Dated: October 28, 2019

Respectfully submitted

/s/ Shannon Eddy

Shannon Eddy
Executive Director
Large-scale Solar Association
2501 Portola Way
Sacramento, CA 95818
Tel: 415-819-4285
E-Mail: shannon@large-scalesolar.org

/s/ Danielle Osborn Mills

Danielle Osborn Mills
Director, AWEA-CA
Renewable Energy Strategies
1970 Meadow Oak Lane
Meadow Vista, CA 95722
Tel: (916) 320-7584
E-Mail:
danielle@renewableenergystrat.com

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #3

M. GRADY MATHAI-JACKSON
KRISTIN D. CHARIPAR

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 30, 2019

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

**INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #3**

Pacific Gas and Electric Company ("PG&E") provides the following informal comments on the Power Charge Indifference Adjustment ("PCIA") Order Instituting Rulemaking ("OIR") Phase 2, Working Group Three, Workshop #3 held on October 17, 2019 (the "Workshop"). While PG&E appreciates the work by Southern California Edison Company ("SCE"), the California Community Choice Association ("CalCCA") and Commercial Energy, collectively the Co-Leads, to develop an initial framework for the allocation of system, local and flexible resource adequacy ("RA"), greenhouse gas ("GHG")-free, and renewables portfolio standards ("RPS") attributes, PG&E does not support the market offer component of the proposal for the reasons described below and has specific concerns with other elements of the proposal. PG&E looks forward to providing additional feedback on the proposals as more details, including implementation details, are developed as part of the working group process.

I. THE INVESTOR-OWNED UTILITIES SHOULD CONTINUE TO OPTIMIZE THE PORTFOLIO ON BEHALF OF BOTH BUNDLED SERVICE AND DEPARTING LOAD CUSTOMERS

During the Workshop, the Co-Leads provided general concepts for the voluntary allocation and market offer ("VAMO") proposals for RPS and system and flexible RA attributes.[1] PG&E supports the general concept of a residual VAMO with the understanding that the investor-owned utilities ("IOUs") will continue to perform portfolio optimization activities

[1] *See* PCIA Phase 2-Working Group 3 Presentation, October 17, 2019, Slide 11.

prior to the annual VAMO activity. PG&E appreciates the Co-Leads in affirming that the VAMO proposal will preserve the IOUs' ability to optimize its portfolio, including through contract assignment, divestiture of resources, contract re-negotiation or through the sale of RA and RPS attributes, and that the VAMO proposal will apply only to residual PCIA-eligible attributes.

To facilitate portfolio optimization or "portfolio right-sizing" activities, PG&E recommends that the Co-Leads restrict the allocation and market offer mechanisms that result in "binding" the IOUs and preventing activities outside of the VAMO to optimize the portfolio in any way. For example, an allocation of local RA attributes to PCIA-eligible load serving entities ("LSEs") occurring beyond the prompt year should not prevent the respective IOU from engaging in portfolio optimization activities (e.g. re-negotiation of contracts, divestiture of resources, longer term sales, etc.) outside of the VAMO activity that would offset costs for all customers paying the PCIA (both bundled service and departing load customers). If an IOU determines it is beneficial to re-negotiate a contract, re-assign a contract or physically sell a local RA resource, a forward year allocation resulting from VAMO should not restrict the IOU from undertaking or delaying that activity until a timeframe when an allocation for LSEs has not yet occurred.

PG&E understands the Co-Leads will provide additional details at the next Working Group Three workshop on how "portfolio right-sizing" inter-plays with the VAMO proposal and looks forward to providing feedback as more details are developed.

II. THE ALLOCATION OF ATTRIBUTES SHOULD BE ON A SHORT-TERM BASIS AND RETAIN LONG-TERM ATTRIBUTES

Under the VAMO proposal, the Co-Leads detailed two allocation structures for RPS to preserve the long-term (10+ years) attributes. SCE and Commercial Energy proposed that the allocation structure preserve long-term attributes regardless of the term of the allocation, including for an allocation on a prompt-year only basis. On the other hand, CalCCA proposed that the allocation structure require an LSE to accept a 10-plus year RPS allocation to preserve long-term attributes.

PG&E supports the SCE and Commercial Energy proposal, and recommends that the allocation structure of RPS attributes:

- maintain their long-term attributes;
- be on a prompt-year only basis;
- be set on a percentage basis rather than by a set quantity.

Long-term allocations would impede IOUs' portfolio optimization activities and create unnecessary risks.

To be clear, while PG&E supports an allocation structure for the prompt-year only and should maintain its long-term attributes, PG&E believes that any further short-term sales of RPS attributes that occur outside of the VAMO proposal or as a part of the VAMO auction (or market offer) mechanism should not maintain its long-term attributes even if that attribute would have been associated with a long-term allocation.

III. THE ALLOCATION PROPOSAL FOR RESOURCE ADEQUACY CREATES ADDITIONAL RISK ON THE INVESTOR-OWNED UTILITY FOR REPLACEMENT CAPACITY

PG&E generally supports the concept of allocating under the VAMO proposal, including allocation of system and flexible RA on a voluntary basis and of local RA on a mandatory basis to all PCIA-eligible LSEs, and appreciates the Co-Lead's efforts in putting forward the proposal. PG&E understands the allocation proposal for RA intends for the RA attributes to be allocated to LSEs in a fashion that is similar to the process established for the cost allocation mechanism ("CAM"). PG&E has some concerns that, under this proposal, the respective IOU would "show" the RA capacity on behalf of all LSEs without consideration of a specific resource's actual availability (e.g. hydrological conditions, planned maintenance outage or unplanned outage). PG&E requests that the Co-Leads provide a specific proposal for how all potential RA penalties and compliance risks will be shared between the IOU, energy service providers ("ESPs") and community choice aggregators ("CCAs") under this proposal.

PG&E is concerned that, given this background, the current VAMO proposal for RA attributes may not appropriately and equitably share compliance risk. As a scheduling coordinator in the CAISO's energy market, PG&E, under CAISO Tariff Section 9 and Section 40.9.3., will retain replacement obligations for RA capacity shown that is on planned maintenance outage or unplanned outage. In the case of an outage, the availability standard penalties (e.g. resource adequacy availability incentive mechanism ("RAAIM")) can be equitably shared under the current PCIA structure, but some penalties and risks may be impossible to share across customers and across LSEs. For example, under current rules, the potential Federal Energy Regulatory Commission ("FERC") investigation of non-compliance or operational risks associated with a CAISO-cancelled outage due to insufficient replacement capacity would be solely borne by the IOU. Additionally, while conceptually it makes sense to share non-compliance penalties (e.g., Capacity Procurement Mechanism ("CPM"), Commission RA compliance penalties), it is not clear how these penalties can be allocated through PCIA rates.

In addition to the issue of unshared compliance risk, it may be difficult and costly to procure replacement capacity due to an outage in today's tightened RA market and in a short-term timeframe. As mentioned in its informal comments to the PCIA Phase 2, Working Group Three, Workshop #2 held in July 2019, PG&E needs to retain capacity within its portfolio should CAISO require replacement capacity for a specific resource outage. PG&E is concerned that the VAMO proposal would not allow for the retention of capacity needed for resource outage replacement even though it may be required under the CAISO Tariff.[2]

Because the current VAMO proposal shifts risks to the IOU, but provides certainty in the allocations from an uncertain portfolio of resources that the IOU is left to manage, PG&E recommends that the Co-Leads consider accounting for unit-specific resource availability as part of the RA attributes that would be allocated to PCIA-eligible LSEs. Specifically, the capacity of

[2] *See* CAISO's Business Practice Manual for Reliability Requirements, Version 44, Section 9 "Resource Adequacy Substitution".

the unit-specific resource that is unavailable would not be allocated to PCIA-eligible LSEs. This could address that additional risks and help to ensure that costs are not shifted to bundled service customers from departing load as required by statute.[3]

IV. THE PROPOSAL CAN BE MADE MORE EFFICIENT AND LESS COMPLEX BY ENABLING EACH LOAD-SERVING ENTITY TO SELL ITS OWN PCIA ATTRIBUTES IF IT DOES NOT WANT TO KEEP THEM

During the Workshop, the Co-Leads expanded on the VAMO proposal and provided additional details since the PCIA Phase 2, Working Group Three, Workshop #2 held in July 2019. PG&E appreciates the Co-Lead's efforts, specifically on the proposed framework to allocate PCIA-eligible portfolio attributes; however, PG&E believes that the market offer mechanism (previously known as the auction mechanism) is overly complex and sales would be better if performed by each LSE, after the allocation of attributes, where those LSEs could consider the sales in the context of their whole portfolios. In this section, PG&E provides a few items of notable concern, including: (1) the extensive administrative burden placed on the IOUs and Commission to monitor and manage the market offer mechanism; and (2) the lack of any compelling argument for why the IOUs need to sell and manage the allocated attributes on behalf of PCIA-eligible LSEs.

A. The Current Proposal Results in Extensive Administrative Burden Being Placed On The IOUs and Commission to Monitor and Manage the Market Offer Mechanism

Under the proposed market offer mechanism, the IOUs would be required to track, manage and monitor the PCIA-eligible attributes, each with a distinct structure, of the portfolio for all LSEs. For example, GHG-free attributes involve an all-or-nothing allocation with no market offer, system and flexible RA involves a 10 percent increment allocation with a market offer and local RA involves a mandatory allocation with no market offer. Furthermore, the VAMO proposal introduces differing allocation terms (e.g. one year, 10+ years, or for the underlying term of the contract, etc.) and respective caps on long-term sales from the market

[3] *See* Cal. Pub. Util. Code §§ 365.2 and 366.3.

offer mechanism. Given that the IOUs will be conducting portfolio optimization activities outside of the VAMO proposal and could likely be a participant in VAMO, the current complexities and lack of uniformity among the attributes imposes administrative burden and could result in associated risks of litigation. The compressed timeline for market offer sales impedes on other IOU procurement processes, unduly complicates IOU procurement activities and poses significant administrative burden on the IOUs. The IOUs would likely need to create separate teams to perform the market offer sales, resulting in additional and unnecessary costs. Further, the IOU's actions taken on behalf of other LSEs, and the IOU's management of its contract portfolio more generally, will also be subject to review and disagreement, potentially resulting in the need for new or expanded regulatory proceedings and other litigation. PG&E requests that the Co-Leads step back and review the complexity of the current proposal and consider a simpler approach that would be easier to implement, maintain, and preferable to all.

B. Non-IOU LSEs Should Sell Attributes On Their Own Behalf

The VAMO proposal does not appear to offer a compelling argument or benefit for why the IOUs should be the agent to resell the PCIA-eligible portfolio attributes on behalf of other LSEs. Parties have expressed concerns in another proceeding on the IOUs serving in a similar role as a centralized procurement entity on behalf of other LSEs. For example, in the RA OIR proceeding (R.17-09-020), the CalCCA argued that IOUs "…selling RA in the market could present an obvious conflict of interest and enable self-dealing to the benefit of the IOU's bundled service." PG&E recommends that the Co-Leads consider whether they can develop a paradigm that allows the non-IOU LSEs to sell portfolio attributes allocated to them on their own behalf. PG&E also notes that, in the RA proceeding, development of a central procurement entity is a current topic. To the extent a central procurement entity exists, PG&E requests the Co-Leads to consider whether use of such an entity might modify the VAMO proposal.

V. AN ALLOCATION OF ALL ATTRIBUTES, INCLUDING THE BROWN POWER ATTRIBUTE, MUST BE CONSIDERED

During the Workshop, the Co-Leads outlined the mechanisms on the allocation of the PCIA-eligible portfolio, including the allocation of RA, RPS and GHG-free attributes. PG&E notes that the PCIA-eligible portfolio also contains an attribute that has not been considered by the Co-Leads up to this point. Thus, PG&E recommends that the Co-Leads consider how the natural gas or "brown" power attribute of the PCIA-eligible portfolio would be equitably allocated among the LSEs. Any allocation mechanism of the PCIA-eligible portfolio that is ultimately adopted by the Commission should ensure all LSEs equitably receive all attributes.

VI. ALLOCATION OF GHG-FREE ATTRIBUTES MUST BE COORDINATED WITH THE INTEGRATED RESOURCE PLANNING FILING REQUIREMENTS

PG&E supports the general direction of the Co-Leads and the allocation proposal for GHG-free attributes as presented at the Workshop, provided that the allocation mechanisms equally address the GHG content of the remaining "brown" portfolio as discussed above. PG&E understands the allocation proposal for GHG-free attributes intends for the attributes to be allocated to LSEs, which would have an option to voluntarily accept or deny the available pool (non-nuclear or nuclear) of GHG-free attributes. All GHG-free attributes that are not accepted by LSEs would then be re-allocated to the LSEs who accepted the allocation from the first round of allocations. The allocation of GHG-free attributes would be done on an annual basis and would not be bound by the prior year's accepted or denied allocation of attributes.

PG&E recommends that the Co-Leads consider how the allocation of GHG-free attributes, among others, should be coordinated with the integrated resource planning ("IRP") filing requirements. The primary concern for PG&E is that the entire portfolio's content be allocated and shown in IRP filings (i.e. that allocations not be stranded or double counted) so that a clear picture of the state's emissions can be presented to the Commission as part of the IRP process. PG&E recommends that the Co-Leads consider how to mitigate any uncertainties surrounding how allocations should be considered through the IRP process so that all LSEs understand how this proposal would carry through to that proceeding.

VII. PG&E SUPPORTS RATEMAKING OPTION ONE BECAUSE IT MINIMIZES RATEMAKING AND ADMINISTRATIVE COMPLEXITY

During the Workshop, the Co-Leads presented two Ratemaking Options for the VAMO proposal. Of the two options, PG&E prefers Ratemaking Option 1 because it minimizes the ratemaking and administrative complexity, which is not insignificant, and arrives at a fair allocation of the costs and benefits of the portfolio. Under Ratemaking Option 1, when an LSE takes the allocation, the attribute values for RPS and RA in the indifference calculation would be zero, which differs from today's construct where an RPS and RA attributes are valued at the attributes' approved market price benchmark ("MPB"). With this approach, there would be no further need for the Commission to review and calculate MPBs for sold and to further quantify unsold portions of the portfolio, both of which can be administratively burdensome and potentially contentious. Further, the Commission has not yet determined how to benchmark or value long-term RPS sales and there would be no need to pursue that further. Under this approach if an LSE decides to sell its allocated attributes instead of taking the allocation, any realized revenues are returned to the LSE and would not impact the indifference calculation and resulting PCIA rates. The PCIA rates would remain the same as rates calculated under the allocation, which sets the attribute value at zero in the indifference calculation. Although the PCIA rates under Ratemaking Option 1 will be higher than they are under today's construct, the higher PCIA rate reflects the fact that the customer is paying directly for the allocated attributes, which preserves the portfolio value for customers and they receive the value of any allocated amount of a sale, should they choose to do so.

As presented by the Co-Leads, Ratemaking Option 2 would result in a PCIA calculation that is nearly identical to today's calculation in that allocated attributes would be valued at the Commission-approved PCIA MPB for those attributes and auction (or market offer) results would be valued based on the transacted price. There was a sub-bullet in the presentation that is a problematic outcome, if adopted.

Specifically, under Ratemaking Option 2, LSEs taking the allocation would pay the IOUs the market value for the portfolio based on the PCIA MPB which would then be credited to the

Portfolio Allocation Balancing Account. In the case where the LSE decides not to take its attribute allocation, it would instead offer the attributes for sale through the market offer mechanism and the proceeds would then be credited against the indifference calculation and the allocated attributes would be valued at the PCIA MPB for those attributes. This ratemaking construct is very similar to how the indifference amount and resulting PCIA rates are determined today where third-party sales are netted against total costs, less CAISO market revenues, less the value of the retained attributes calculated using an MPB, with the exception that the attributes would be allocated rather than retained. However, the sub-bullet in the presentation also suggested that there may be a preference that the MPB be set based on the auction (or market offer) results only, and this proposal was supported by a statement that LSEs would be indifferent to taking allocation or monetizing allocation through sales if the MPB used in Ratemaking Option 2 were set based on the "Auction Price Benchmark." The Commission has previously determined how to set MPBs and noted the need to potentially develop long-term RPS benchmarks as well. There is no requirement that LSEs be indifferent when deciding whether they take the allocation or have the IOUs sell the allocation on their behalf. There is, however, a statutory requirement that customers are indifferent when setting PCIA rates, and customer indifference can only be achieved when the market value is calculated using a true MPB. Valuing the portfolio attributes based on what could be a very thin amount of trading activity conducted through the VAMO proposal almost guarantees that the auction (or market offer) prices would not be reflective of the actual market activity, much of which will be transacted outside of these VAMO proposal. Instead, the auction (or market offer) results should be reported to the Commission along with other market transaction activity, as required by the protocols established in Decision 19-10-001, and folded into the MPB calculation.

Customer indifference can only be achieved if the portfolio's attribute value is based on actual market prices and activity, which was the subject of the debate in Phase 1 of the PCIA OIR. There is no reason to revisit how to value retained or allocated attributes – the values of these attributes should be based on a broad survey of actual market transactions as approved in

Decision 19-10-001. To do otherwise will result in cost shifts between bundled service and departing load customers.

VIII. ADDITIONAL ISSUE FOR CONSIDERATION

PG&E recommends the following additional issue for consideration related to the VAMO proposal as presented by the Co-Leads in Working Group Three: implementation of VAMO may require changes to existing rules and new legislation.

PG&E notes that the PCIA-eligible IOUs' portfolios represent a significant portion of the state's generation and contain products subject to legislative restrictions and regulated by multiple state agencies or organizations. As such, it is important for the proposed paradigm to outline the regulatory rule changes and/or legislation required to: (1) maintain the value of the portfolio; and (2) ensure that its allocation does not impair California's ability to meet its energy and environmental goals. For example, to maintain the portfolio value, any proposal should ensure or, at a minimum, maximize, the underlying long-term value and portfolio content category ("PCC") 1 status of RPS resources. Additionally, to support state policy, any proposal should be consistent with the intent of the California Energy Commission's PCL and not result in under-reporting of natural gas emissions.

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IX. CONCLUSION

PG&E respectfully requests that these informal comments inform the Commission's consideration of the allocation and market offer mechanism proposal.

Respectfully Submitted,

By: /s/ M. Grady Mathai-Jackson
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON THE WORKING GROUP 3 CO-CHAIRS' ALLOCATION AND AUCTION PROPOSALS

Tyson Siegele
Energy Analyst
PROTECT OUR COMMUNITIES FOUNDATION
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: October 25, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON THE WORKING GROUP 3 CO-CHAIRS' ALLOCATION AND AUCTION PROPOSALS

I. Introduction

On October 17, 2019, the co-chairs of Working Group 3 convened a workshop at which they presented the results of their discussions and deliberations to date. Protect Our Communities Foundation ("POC") participated in the October 17, 2019 workshop and provides the following informal comments pursuant to the schedule set by the co-chairs.

POC supports the continued inclusion of the Market Price Benchmark in the PCIA rate. The current Market Price Benchmark appropriately places a value on resources that are designated for sale to the market. It was developed and vetted in a lengthy process. POC strongly opposes the proposal by Southern California Edison ("SCE") and Commercial Energy to remove the Market Price Benchmark from the PCIA.

Next, POC supports the exclusive use of slice of generation contracts in the auction of Renewable Portfolio Standard ("RPS") attributes. When investor-owned utilities ("IOUs") have discretion in the contracting of Power Charge Indifference Adjustment-eligible ("PCIA") resources belonging to unbundled customers, controversy inevitably results. The co-chairs should avoid such controversy by requiring the exclusive use of slice of generation contracts.

POC opposes implementing a cap on long-term RPS sales because a cap would limit auction revenues and maximizing the value of those revenues is important.

POC supports the allocation and auction of every type of resource attribute. The co-chairs' proposal should include an auction for local resource adequacy ("Local RA") and greenhouse gas-free attributes.

II. The Co-Chairs Should Not Remove the Market Price Benchmark from the PCIA.

POC supports a rate structure that retains the Market Price Benchmark. Option 1, which would remove the Market Price Benchmark from the forecast that sets the PCIA rate is untenable for departing load customers. Removing the credit that represents the value of PCIA-eligible resources will result in a substantially higher and inequitable PCIA rate. POC supports fairly valuing PCIA resources before any sales are made and option 2 appears to meet POC's objective.

Option 1 violates the guiding principle of this docket: customer indifference. Option 1 would require the rates of an unbundled customer whose Load Serving Entity ("LSE") declines its allocation of PCIA-eligible resources to include the full cost of both resources declined by its LSE and resources acquired by its LSE. The fact that the LSE receives a credit for the value of auction revenues later in the year does not alleviate the need for its rates to cover the cost of the resources acquired before the credit arrives. Unbundled customers should not be required to bear the cost of attributes that their LSE declines *at any time*.[1]

Further, option 1 unreasonably transfers the burden of administration of PCIA bill credits from the IOUs to other LSEs. Today, the IOUs are responsible for calculating the cost of PCIA-eligible resources, forecasting the sale of attributes from PCIA-eligible resources, and calculating a vintaged PCIA rate based on that forecast in the ERRA proceeding. IOUs then track the revenue collected from unbundled customers by vintage, make sales of attributes from PCIA-

[1] Unless the attributes fail to sell at auction.

eligible resources, and track the revenues from those sales by vintage. Finally, the IOUs calculate the difference between revenues and costs in its PABA proceeding and collet net PCIA costs from customers. Option 1 provides revenues from sales to LSEs instead of applying the revenues as a credit to the customer's PCIA rate. In this way, option 1 transfers the administrative burden of tracking each customer's vintage and PCIA bill credit to LSEs that have not built the infrastructure necessary to perform such calculations, and may not have the information necessary to perform the calculations. For these reasons, option 1 is unreasonable, inequitable, and impractical.

The co-chairs presented an additional alternative where the Market Price Benchmark is set at the auction clearing price. The current Market Price Benchmark includes all available transactions in the previous year. POC does not support using the auction price as the Market Price Benchmark because its sample size is too small to comprise a reasonable estimate of the ongoing value of PCIA-eligible resources. POC recommends instead that the forecasted Market Price Benchmark continue to be set using all available transactions in the previous year. Actual auction revenues should be used as the final credit in the true-up.

III. POC Supports the Use of Slice of RPS Generation Contracts.

The co-chairs proposed that bidders may use either firm quantity, contingent, or slice of generation contracts in the auction of declined RPS. POC believes that these auctions should accept bids exclusively on slice of generation contracts. The use of firm quantity contracts is not appropriate because it would necessarily rely on the IOUs' discretion to select a mix of firm and non-firm contracts. In this working group's experience, when IOUs are provided discretion in the sale of PCIA-eligible resources belonging to unbundled customers, controversy inevitably results. For example, Peninsula Clean Energy sought to purchase Local RA for the 2019 reliability year. Peninsula Clean Energy responded to all of PG&E's requests for offers and made other efforts to procure capacity, but was unable to procure enough local RA to meet its need.[2] PG&E used its discretion to offer the needed capacity to the market only after the compliance deadline for LSEs to obtain RA for 2019.[3] In an effort to avoid a similar controversy surrounding the sale of RPS, and to restrict the IOUs' discretion in administering sales from resources belonging to unbundled customers, the co-chairs should require all RPS sales to use slice of generation contracts.

IV. A Cap on Long-Term RPS Sales Is Unnecessary.

POC disagrees with the co-chairs' proposal to cap the quantity of long-term sales made in the RPS auction. To capture the most value for the RPS product, IOUs should always accept the highest price offered for the sale of RPS regardless of contract length. A large quantity of renewable resources will enter the market as California moves towards its statewide renewable energy goals and more CCAs with aggressive renewable energy mandates form. With this influx of new renewable resources—built with the advantage of today's prices that are generally lower than the cost of the RPS resources in the PCIA portfolio—the market price of RPS products is likely to drop precipitously in the next several years. Therefore, the PCIA auction mechanism should capture the highest value of RPS products available in the near term. POC believes that the ability to secure long-term revenues for RPS resources in the near term is more important than ensuring that allocations from the PCIA portfolio are available to customers who switch between LSE providers.

V. Portfolio Optimization Mechanisms Should Promote the Sale of Entire Resources and Every Type of Resource Attribute.

Portfolio optimization mechanisms should promote the sale of PCIA-eligible resources in

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[2] Notice of Ex Parte Meeting of the California Community Choice Assn., at p. 2 (May 13, 2019).

[3] *Id*.

a manner that ensures the greatest value for customers. First, IOUs should prioritize the sale of entire resources, which would create value for customers who would otherwise pay the full cost of those resources through the PCIA. Portfolio optimization mechanisms should also capture the full value of all a resource's attributes. Accordingly, long-term portfolio optimization mechanisms should allow for the sale of entire resources and buyout of power purchase contracts; short-term portfolio optimization mechanisms should allow for the sale of every type of resource attribute.

At the workshops, SCE stated that it does not want to be involved in transacting Local RA or greenhouse gas-free nuclear and hydro ("GHG-free") attributes. However, Commission directives control policy, not IOU preference. The IOUs are obligated to manage their portfolios prudently, which includes taking affirmative actions to transact PCIA-eligible resources in a way that creates the most value for all customers. It is imprudent for an IOU to withhold value from customers simply because an IOU prefers not to transact.

The following two sections describe issues still pending from POC's August 9, 2019 comments regarding Local RA and GHG-free auctions that remain relevant for the co-chairs' consideration today.

A. POC Supports the Co-chairs' Local RA Allocation Proposal When Paired With an Auction.

The co-chairs offer a proposal that allocates local RA to LSEs. POC supports the premise of this proposal as a short-term portfolio optimization mechanism if it is paired with an auction. Below, POC proposes a change to the local RA proposal's treatment of penalties.

First, POC disagrees with the co-chairs proposal that

> "any CAISO . . . penalties required for, or imposed as a result of, local RA resource outages will receive full cost-recovery through the PCIA . . . except for

> any costs disallowed through the IOU's [Energy Resource Recovery Account ("ERRA")] proceeding."[4]

Penalties should not automatically be eligible for recovery in the PCIA. IOUs maintain a responsibility to prudently manage their PCIA-eligible resources to avoid any penalties. Therefore, it is unreasonable to presume that these penalties are customers' responsibility. Instead, shareholders should take financial responsibility for any penalties, as they are responsible for managing their PCIA-eligible resources in a way that avoids the imposition of penalties.[5] Should shareholders seek to impose the cost of penalties on departing load customers, an IOU should be required to file an application, in a docket distinct from the ERRA proceeding, showing why these costs should be customers' responsibility. Put simply, penalties that result from imprudent management of resources should be shareholders' responsibility.

Second, the proposal allows the trading of allocated local RA attributes, but it does not define trading.[6] In response to a question from POC at the July 25, 2019 meeting, the co-chairs stated that trading includes sales. The revised proposal presented at the October 17, 2019 workshop continues to omit a definition of trading. The co-chairs' proposal should define the term trading to include sales.

B. POC Supports the Co-chairs' GHG-free Allocation Proposal When Paired With an Auction.

The co-chairs offer a proposal that allocates a proportional share of GHG-free attributes to other LSEs.[7] This proposal makes sense because GHG-free attributes have a value, and all

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[4] July 25, 2019 Presentation at 25.

[5] If IOUs cannot manage their resources without incurring penalties, or do not want the obligation of resource management, they should sell those resources.

[6] July 25, 2019 Presentation, at 24.

[7] July 25, 2019 Presentation at 26-30.

customers who pay the PCIA are entitled to a portion of that value.[8] POC supports the premise of this proposal as a short-term portfolio optimization solution if it is paired with an auction. POC also suggests two clarifications to improve the co-chairs' GHG-free proposal.

GHG-free resources include nuclear and hydroelectric resources. Some Community Choice Aggregators ("CCAs") are not authorized to purchase or use nuclear resources, therefore any GHG-free allocation proposal should include a mechanism allowing LSEs to opt out of receiving GHG-free attributes from nuclear resources. The co-chairs disagree on what to do with the declined GHG-free attributes from nuclear resources. Commercial Energy would auction the declined attributes and credit the auction proceeds to the LSEs declining the attributes.[9] CalCCA and SCE would similarly allow LSEs to decline receiving GHG-free attributes from nuclear resources, but instead of auctioning off the declined attributes, they "would be reallocated automatically amongst LSEs participating in the allocation."[10]

POC supports Commercial Energy's proposal because it provides the LSE declining an allocation of GHG-free attributes the financial value of the attributes to which it was entitled. In contrast, CalCCA and SCE would allocate the value of attributes paid for by one LSE to the customers of another LSE without compensation. CalCCA and SCE offer no support for their proposal to allocate the value of attributes from one LSE to another without compensation. This aspect of the proposal offered by CalCCA and SCE should be rejected because it is unjust, unreasonable, and unfair that a customer who paid for a resource would not receive the value of

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[8] *See* July 25, 2019 Presentation at 27 (a "credit within [the] Power Content Label, Clean Net Short, or other similar reporting mechanisms").

[9] *See* July 25, 2019 Presentation at 28; *Id*. at 33.

[10] July 25, 2019 Presentation at 28

the resource.

Finally, as noted with proposal regarding the sale of RA attributes, the co-chairs' proposal allows the trading of allocated GHG-free attributes but does not define the term trading.[11] The co-chairs' proposal should define the term trading to include sales.

VI. Conclusion

POC thanks the co-chairs for the opportunity to submit these comments and looks forward to participating in the Working Group process in the future.

DATED: October 25, 2019 SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai

ELLISON FOLK
YOCHANAN ZAKAI*
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: October 25, 2019 PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele

TYSON SIEGELE
Energy Analyst
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

[11] July 25, 2019 Presentation, at 28.

* Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF CITY OF SAN JOSE (SAN JOSE CLEAN ENERGY) ON WORKING GROUP 3's PHASE 2, WORKSHOP # 3 REGARDING PORTFOLIO OPTIMIZATION AND ALLOCATION AND AUCTION

RICHARD DOYLE
City Attorney

LUISA F. ELKINS
Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San José, CA 95113-1905
Tele: (408) 535-1953
Email: luisa.elkins@sanjoseca.gov

Attorneys for the City of San José, administrator of San José Clean Energy

October 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF CITY OF SAN JOSE (SAN JOSE CLEAN ENERGY) ON WORKING GROUP 3's PHASE 2, WORKSHOP # 3 REGARDING PORTFOLIO OPTIMIZATION AND ALLOCATION AND AUCTION

The City of San José ("San José"), on behalf of San José Clean Energy ("SJCE"), respectfully submits the following informal comments on the October 17, 2019 Phase 2, Workshop #3, hosted by the Working Group 3 ("WG3") regarding Portfolio Optimization and Allocation and Auction ("Workshop #3"). SJCE appreciates the opportunity to provide these comments and supports all efforts from stakeholders and the California Public Utilities Commission ("Commission") to improve the resource adequacy ("RA") market.

I. DISCUSSION

A. Timing for RA Allocation and Auction

At Workshop #3, WG3 presented a timeline for the voluntary allocation and market sale of system and flexible RA that would fit within the current Commission RA schedule. Under this timeline, the open enrollment period for allocations would occur during mid-August, with market offer of unallocated RA products occurring around mid-September or early October. At the workshop, the CalCCA co-lead stated that WG3 may consider proposing a revised Commission timeline as part of this working group to allow load serving entities ("LSEs") sufficient time to procure RA prior to the October 31st compliance deadline. SJCE emphasizes that it is extremely important that the timeline be shifted up. Market offer of unallocated RA products should occur prior to the end of April, and the Commission timeline must be adjusted accordingly. An end-of-April allocation and auction would ensure that unallocated products are available on the market for six months prior to the compliance deadline for orderly procurement of resources, in contrast to the mere weeks that are suggested under the current timeline.

B. Long-Term Allocations and Sales

During Workshop #3, the CalCCA co-lead indicated that WG3 is not currently considering longer-term (e.g., more than a year) allocations and sales for system and flexible RA, and that one-year allocations are preferred because they give LSEs the most flexibility to respond to Commission RA rule changes, which often occur from year to year. While SJCE agrees that it is certainly beneficial to have options for one-year allocations and sales for maximum flexibility, opportunities for LSEs to access multi-year system and flexible RA are also necessary to enhance market stability. SJCE is assessing several long-term contracts for RA, and it is very likely that other LSEs are doing so as well. If LSEs begin fulfilling a significant portion of their RA obligation with long-term contracts, the interest in one-year contracts or allocations would eventually be low. SJCE recommends that long-term options for RA are included as part of the WG3 proposal to increase options for LSEs.

Regarding long-term allocations and sales for Renewable Portfolio Standard ("RPS") credits, SJCE agrees with CalCCA that allocations and sales must be for 10+ year terms to qualify as long-term RPS under statutory requirements.

C. Ratemaking Proposals

Two ratemaking proposals were presented during Workshop #3. Of the two proposals, SJCE supports CalCCA's ratemaking proposal and strongly opposes the ratemaking option presented by Southern California Edison (WG3 co-lead) and Commercial Energy. Customers would see a much higher Power Charge Indifference Adjustment ("PCIA") than they do today under this latter proposal because all the costs of the resource go into the PCIA. As acknowledged at Workshop #3, the ratemaking methodology proposed by these parties would make it very challenging for Community Choice Aggregators to index their rates based on investor-owned utility rates due to the mismatch between the timing of the PCIA payment and the auction from which revenues are received.

Respectfully submitted by:

RICHARD DOYLE
City Attorney

/s/ Luisa F. Elkins

LUISA F. ELKINS
Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San José, CA 95113-1905
Tele: (408) 535-1953
Email: luisa.elkins@sanjoséca.gov

Attorneys for the City of San José, administrator of San José Clean Energy

Dated: October 28, 2019

A Sempra Energy utility®

November 8, 2019

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PCIA WORKING GROUP 3 THIRD WORKSHOP (R.17-06-026)

SDG&E appreciates the opportunity to provide these comments regarding the co-chairs' Working Group 3 proposal. In Decision (D.) 18-10-019, the Commission ordered initiation of Phase 2 of the proceeding to "consider the development and implementation of a comprehensive solution to the issue of ***excess resources*** in utility portfolios. We expect that solution to be based on a voluntary, market-based redistribution of excess resources in the electric supply portfolios of [the Investor Owned Utilities ("IOUs")]."[1] The Phase 2 Scoping Memo directed parties to address four topics. The three workshops held to date by Working Group 3 have focused on answering the first of these four issue areas:

> What are the structure, processes, and rules governing portfolio optimization that the Commission should consider in order to address excess resources in utility portfolios? How should these processes and rules be structured so as to be compatible with the Commission's ongoing Integrated Resource Planning and [Resource Adequacy ("RA")] program modifications in other proceedings?

The issues tackled by Working Group 3 are among the most difficult and contentious of the proceeding. Developing the framework envisioned by the Commission is no easy task, and SDG&E appreciates the significant time and effort the co-chairs have devoted to the exercise. While the co-chairs have made substantial progress, the allocation proposal does not fully meet the directive set forth in the Phase 2 Scoping Memo, with a major impediment being the current impasse regarding the definition and quantity of buffer and uncertainty. SDG&E urges the co-chairs to reengage with this effort, and offers the following observations to help pinpoint areas of future focus:

First, the allocation proposal only partially deals with the utilities' excess resources. In a scenario where the IOU has no excess resources above the bundled customers' needs, the mandatory allocation methodology would distribute RA attributes and renewable energy credits ("RECs") to the community choice aggregators ("CCAs") that gained the departed customers based on their forecasted load share. This, in turn, creates additional costs to bundled customers since the IOU must procure additional products in the bilateral market to meet its customers'

[1] D.18-10-019, p. 4 (emphasis added).

needs to the extent that the IOU is short after the allocation process. On the other hand, if the IOU has excess resources even after the allocation process, it would signify that the allocation methodology did not distribute the entirety of the excess resources to departed load and the IOU would still have excess resources that it may or may not elect to sell in the bilateral market. In either case, the allocation proposal does not answer the question of how the IOU must optimize excess portfolio.

Second, the allocation proposal potentially limits the IOUs' ability to optimize its portfolio in the future because the long-term allocations are binding. This would limit any sale of the resource to a buyer because the buyer may not wish to be obligated to continue to allocate products in the long-term. The IOUs must have the flexibility to "right-size" their portfolios and meet the directive in the Phase 1 decision to reduce overall costs for customers as load departure occurs. The binding allocation does not offer this flexibility and effectively requires the IOUs to keep resources on its balance sheet in the long-run that it no longer needs to serve its load.

Third, SDG&E does not support the proposal to allow load-serving entities ("LSEs") to trade allocations rather than actual RA capacity with other LSEs. This proposal creates a new product that is a derivative of the current RA capacity product construct. SDG&E does not believe a new RA product should be developed in order to facilitate the allocation methodology and potentially increase the complexity of the tracking mechanism under the current RA framework. SDG&E prefers that LSEs continue to transact based on the current net qualifying capacity ("NQC") RA product that is prevalent in the current bilateral market construct.

Fourth, SDG&E cannot support a construct that shifts long-term RPS portfolio risks to its bundled customers. SDG&E fears that allocating firm products from the IOU portfolio for future delivery periods (*e.g.*, long-term allocations) could impose unnecessary risks to bundled customers given the fluctuating nature of portfolio deliveries. Also, considering imminent load departure, SDG&E endeavors to "right-size" its portfolio and submits that long-term allocations inhibit its ability to meet the Commission's directive to do so. SDG&E requests that in the next workshop, the co-leads discuss contract assignment/novation, buy-outs and other available optimization tools as a means to address LSEs' requests for long-term resources and SDG&E's desire to "right-size" its portfolio.

Finally, all portfolio optimization paradigms – including allocation – must ensure fair treatment. This means that *every* attribute of a resource type, including the brown power component, must be subject to allocation. This is fundamental to establishing an equitable allocation process. Allowing non-IOU LSEs to receive allocations from only greenhouse gas ("GHG")-free resources would mean that only IOU portfolios would include energy from GHG emitting resources – even though this energy was procured to serve the customers that later departed utility service. In an allocation construct, IOUs should be permitted to allocate to departed load their fair share of *all* PCIA portfolio eligible attributes, including the energy from GHG emitting resources along with the GHG-free resources.

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**BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

**COMMENTS OF THE UTILITY REFORM NETWORK ON
THE PHASE 2 WORKING GROUP #3 WORKSHOP #3**

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Matthew Freedman, Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org
October 28, 2019

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #3

TURN offers the following comments on certain issues reviewed in the 3rd workshop of Working Group 3 (WG 3), regarding portfolio optimization and cost reduction, and allocation and auction. Citations refer to slides presented at the 3rd workshop (Presentation).

Allocations of long-term contract compliance attributes

Stakeholders disagree about the required elements of the proposed voluntary allocation structure that would allow LSEs to use IOU contracted RPS eligible resources to satisfy the long-term contract compliance obligations established under Public Utilities Code §399.13(b). While CalCCA argues for a minimum allocation term of at least 10 years, SCE and Commercial Energy propose no minimum allocation term.[1]

CalCCA is correct. In order for an LSE to demonstrate compliance with the long-term contracting requirement, it must enter into a binding and specific commitment that extends into the future for a duration of at least 10 years. In D.17-06-026, the Commission affirmed that any "repackaging" of a long-term contract must remain consistent with the approach adopted in D.12-06-038.[2] Each retail seller must demonstrate that it has made a long-term commitment (via ownership or contract) for output from RPS-eligible facilities. Under no circumstances does "repackaging" permit any long-term contract or ownership agreement to retain its compliance value under §399.13(b) if it is resold or allocated for a term of less than 10 years. The language of §399.13(b) expressly requires that the retail seller must procure sufficient quantities from "its contracts of 10 years or more in duration" to satisfy the obligation.

There is no basis to allow any short-term procurement allocation to a retail seller to satisfy the requirements of §399.13(b) even if there is a demonstration that the

[1] Presentation, page 14.
[2] D.17-06-026, pages 21-22.

underlying contract executed by the IOU with the RPS-eligible facility involves a long-term commitment. In D.12-06-038, the Commission rejected requests by several parties to permit “slicing and dicing” of eligible long-term contracts into short-term resale contracts that retain a “long-term” attribute.[3] In D.18-05-026, the Commission reaffirmed this treatment in rejecting a petition by Shell to allow the requirements of §399.13(b) to be satisfied when a long-term contract is repackaged with portions resold to a subsequent buyer making a commitment of less than 10 years.[4]

Given the clear statutory language and a line of unambiguous Commission decisions interpreting the nature of the requirements, there is no basis for WG3 to propose an approach to allocation that seeks to transfer “long-term contract attributes” without an offtake commitment of less than 10 years in duration. TURN strongly urges the WG3 co-leads to conform any final proposal to these requirements.

<u>Any voluntary allocation of RPS or GHG-free resources must be structured as a forward sale of a bundled product</u>

The proposed voluntary allocation of RPS and GHG-free resources would allow LSEs to accept an assignment of a share of the IOU portfolio. Without taking a position on the two ratemaking options outlined in the presentation, TURN believes that the WG3 proposal must take great care to conform to existing conventions relating to the forward sale of bundled products.

It is not entirely clear from the presentation whether the structure for allocating both RPS and GHG-free resources is consistent with the approach currently used by IOUs for selling these products on a forward basis. TURN would be particularly concerned about any initiative to create a new class of unbundled GHG-free attributes that can be traded

[3] In R.11-05-005, both Noble and PG&E requested changes to the long-term contract obligations that would have permitted short-term contracts to substitute for long-term contracts required under the RPS obligations. The Commission declined to adopt this treatment in D.12-06-038.
[4] D.18-05-026, pages 25-27.

separately from the electricity generated by the associated units. Any such scheme would run afoul of both the Clean System Power methodology used in the Integrated Resource Planning (IRP) process and the California Energy Commission's Power Source Disclosure Program (PSDP). Neither program allows LSEs to acquire unbundled attributes that can be used to offset portfolio GHG emissions for reporting purposes.

So long as all allocated products are conveyed on a forward basis and include attributes bundled with the associated electricity from the underlying generator, the proposals under consideration by WG3 should not conflict with the IRP and PSDP protocols. TURN would appreciate clarifications with respect to this issue as part of any final working group report submitted to the Commission.

TURN appreciates the opportunity to submit these comments.

Respectfully submitted,

MATTHEW FREEDMAN

__________/S/___________

Matthew Freedman
Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: October 28, 2019

Appendix C

INFORMAL COMMENTS ON ISSUES 2 TO 4

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

PROTECT OUR COMMUNITIES FOUNDATION'S PROPOSALS FOR PORTFOLIO OPTIMIZATION

Tyson Siegele
Energy Analyst
Protect Our Communities Foundation
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: November 4, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

PROTECT OUR COMMUNITIES FOUNDATION'S PROPOSALS FOR PORTFOLIO OPTIMIZATION

I. INTRODUCTION

On October 17, 2019, the co-chairs of Working Group 3 convened a workshop at which they requested that parties submit proposals via informal comments to the service list by November 4, 2019. Protect Our Communities Foundation ("POC") submits these comments pursuant the schedule set by the co-chairs.

POC requests that its proposals be discussed at one or more of the co-chairs' weekly meetings, and that the co-chairs invite POC to participate fully in the discussion of its proposals.

In these comments, POC recommends that the working group consider mechanisms designed to remove resources from investor-owned utilities' ("IOUs'") portfolios. The best mechanism to facilitate the removal of resources from the IOUs' portfolios is a sunset of the Power Charge Indifference Adjustment ("PCIA"). POC proposes that the PCIA sunset five years following a customer's departure from bundled service. Under POC's sunset proposal, IOUs are responsible for managing their portfolios such that the portfolio contains no excess resources five years following a customer's departure from bundled service. If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.

Next, any portfolio optimization mechanisms proposed by the co-chairs should facilitate the transfer of a large quantity of resources because an IOU may need to transfer a large quantities of resources from its portfolio.

Finally, POC believes that all of working group 3's proposals should include automatic enforcement and shareholder responsibility mechanisms. Accordingly, we present specific proposals for automatic enforcement of the co-chairs' allocation and auction proposal.

II. The Working Group Should Consider Mechanisms Designed To Remove Resources From IOU Portfolios.

IOUs should prioritize the sale of entire resources, which would create the most value for customers who are responsible for paying the full cost of those resources through the PCIA. Long-term portfolio optimization mechanisms should allow for the sale of entire resources and the buyout of power purchase contracts for which an IOU has no long-term need. Since submitting our first set of comments to this working group six months ago, POC has asked for the working group to consider the removal of entire resources from IOUs' portfolios. As the Alliance for Retail Energy Markets noted in their most recent comments, this is the most important issue that the working group was charged to resolve,[1] and one that the working group should have prioritized addressing from day one. While we are disappointed that the co-chairs have not responded to our previous comments on this issue, we look forward to working on this topic with the co-chairs moving forward.

POC is concerned about the ability of the working group to develop an effective proposal in the time available before the working group's final report is due on January 30, 2020. If the co-chairs are not able to develop a proposal that results in IOUs divesting entire resources, they

[1] Alliance For Retail Energy Markets Informal Comments On PCIA Working Group 3 Meeting #3, at pp. 1-2 (October 28, 2019).

should submit their allocation and auction proposal for Commission consideration and request additional time for the working group to develop an effective proposal to address this critical issue.

The allocation and auction proposal provides a way to transfer specific resource attributes from IOUs to other load serving entities ("LSEs") on an annual basis. Such a short-term transfer of attributes does not obviate the need for IOUs to divest from their portfolios those resources that they do not need in the long-term. As we noted in earlier comments, POC's support of any short-term transfer of individual attributes is coupled with its strong desire to see a long-term portfolio optimization mechanism that removes resources from the IOUs' portfolios. The best mechanism to facilitate the removal of resources from the IOUs' portfolios is a sunset of the PCIA.

A. The PCIA Should Sunset In Five Years.

After five years, no unbundled customers should be responsible for paying for the costs of IOU-controlled resources. In 2002 the legislature enacted AB 117 directing the Commission to create a short-term solution to account for resources procured on behalf of customers that switch to a community choice aggregation program ("CCA"). AB 117 specifically instructed that the PCIA be for a limited period of time.[2] The legislature did not describe the PCIA as a long-term solution because an IOU would eventually downsize its portfolio to eliminate the need to charge departed customers for excess resources. IOUs have been on notice for seventeen years that their portfolios must be managed to remove excess resources following the creation of a CCA.

[2] Pub. Utils. Code § 366.2(f)(2).

IOUs should be assigned the responsibility to downsize their portfolios by a date certain. If IOUs are provided a deadline by which to have a right sized portfolio, IOUs will take appropriate actions before that deadline. These actions could include letting existing contracts expire, taking decisive positions against additional and unneeded procurement requirements, contract buyouts, and selling owned generation. Setting a long-term goal for IOUs to right size their portfolios has the added benefit of not requiring the Commission or stakeholders to micromanage the IOUs' portfolio management activities. In order for the Commission and stakeholders to be confident that the IOUs will meet the goal set by the Commission, the deadline should be mandatory and include financial consequences for shareholders as described below.

POC proposes that the PCIA sunset in five years. While IOUs may administer contracts for resources that are longer than five years in length, utilities have ongoing opportunities to renegotiate contract terms and propose the buyout or transfer of contracts to other LSEs. Similarly, the fact that an IOU owns a resource does not mean that CCA customers should be responsible for paying for a utility-owned resource in perpetuity. Instead, IOUs should sell unneeded resources.

For example, if POC's proposal is adopted in 2020, then IOUs must manage their portfolios to eliminate excess resources and PCIA costs for all customers that departed bundled service in 2020 or earlier by 2025. At that point, the IOUs would have had 23 years after the legislature enacted AB 117 to prepare for the phase out of PCIA fees. If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.

The five year sunset would also apply to CCAs formed after the proposal is adopted. For example, if a customer departs bundled service in 2021, then the IOU must manage its portfolio to eliminate excess resources and PCIA costs for that vintage by 2026. In this way, the PCIA would not be imposed on a vintage of customers for more than five years.

B. Portfolio optimization mechanisms should facilitate the transfer of a large quantity of resources.

In addition to sunsetting the PCIA, the co-chairs could consider other mechanisms to remove resources from IOUs' portfolios. If the co-chairs do so, any mechanism should include a structure designed to facilitate the transfer of a large quantity of resources because an IOU may need to eliminate large quantities of resources from its portfolio. For instance, San Diego Gas and Electric ("SDG&E") will need to divest a large quantity of resources. On September 17, 2019, the City of San Diego adopted an ordinance establishing a Community Choice Aggregation ("CCA") program and a resolution to execute a regional CCA Joint Powers Authority ("San Diego CCA"), with the cities of La Mesa, Chula Vista, Encinitas, and Imperial Beach.[3] The San Diego CCA is expected to serve more than 50 percent of SDG&E's load when it begins service in in 2021.[4] Therefore, in designing portfolio optimization mechanisms, the working group should ensure that any mechanism proposed can be used to efficiently divest a large portion of an IOU's resource portfolio. POC repeats its request that the co-chairs evaluate each proposal brought forward to address whether it is able to facilitate the transfer of a large quantity of resources and discuss this evaluation at future meetings.

[3] City of San Diego Informal Comments on Proposed Decision of ALJ Atamturk Refining the Method to Develop and True Up Market Price Benchmarks, at p. 1 (Sept. 26, 2019).
[4] *Id*.

III. All The Co-Chairs' Proposals Should Include Automatic Enforcement and Shareholder Responsibility Mechanisms.

The co-chairs' allocation and auction proposal, as well as any proposals to divest entire resources from IOUs' portfolios, should include automatic enforcement mechanisms to ensure IOUs immediately implement the portfolio optimization mechanisms adopted by the Commission. This section first discusses POC's proposed automatic enforcement and shareholder responsibility mechanism for the co-chairs' allocation proposal, and then discusses the same for co-chairs' auction proposal.

The co-chairs' annual PCIA allocation mechanism requires IOUs to regularly provide to other LSEs the quantity of their forecast and actual allocations of resources attributes. IOUs that do not provide these forecast and actual allocation amounts on a schedule approved by the Commission should provide bill credits to bundled and unbundled customers. These bill credits should be given by IOU shareholders to customers within 60 days of the missed deadline, without the need for any Commission action.

IOUs should administer the PCIA allocation mechanism in a timely, efficient, fair, and transparent manner because they control access to information about the PCIA resources paid for by all customers. POC's automatic enforcement and shareholder responsibility mechanism aligns the interest of shareholders in avoiding penalties with the interests of all customers in an efficient and timely administration of the allocation mechanism. It also compensates customers when they are harmed by an IOU's mismanagement of the allocation mechanism.

For example, IOUs that publish final allocations that underallocate attributes to unbundled customers should provide credits to unbundled customers' bills. Similarly, IOUs that publish final allocations that underallocate resources to bundled load customers should provide automatic credits to bundled customers' bills. Based on the information provided by the co-chairs to date, it is unclear to POC exactly which allocation calculations are to be performed by the IOUs, and which by the Energy Division. POC requests that the co-chairs provide this clarity and work with POC design this automatic enforcement mechanism.

Next, the co-chairs' annual PCIA auction mechanism requires IOUs to regularly administer solicitations for bids on certain attributes from PCIA resources. The efficient administration of these solicitations is an essential part of the co-chairs' proposal to reduce the PCIA rate. Due to the IOUs' track record in administering PCIA resources, POC is concerned that IOUs may not efficiently and accurately administer these auctions. POC's proposal aligns shareholders' interest in avoiding penalties with customers' interest in efficient administration of these auctions.

POC proposes that if an IOU that does not complete its auction on the schedule set by the Commission, within 60 days of the missed deadline the IOU's shareholders should provide bill credits to the unbundled customers on whose behalf the action was to be conducted.

Further, POC proposes that an IOU withholding resources that an LSE requested be auctioned provide bill credits to the unbundled customers on whose behalf the auction was to be conducted. The credit would be in the amount of the highest auction bid, or most recent market price benchmark for that attribute, if no auction took place, multiped by the quantity of attributes not auctioned.

IV. CONCLUSION

POC thanks the co-chairs for the opportunity to submit these proposals, and requests that these proposals be discussed at one or more of the co-chair's private meetings, and that POC be invited to participate fully in the discussion of its proposals.

DATED: November 4, 2019 SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai

ELLISON FOLK
YOCHANAN ZAKAI[*]
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: November 4, 2019 PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele

TYSON SIEGELE
Energy Analyst
Protect Our Communities Foundation
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

[*] Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

Appendix D
FOURTH WORKSHOP PRESENTATION

PCIA Phase 2 – Working Group Three

Portfolio Optimization and Cost Reduction, and Allocation and Auction

Refinement of Issue 1 Proposals; Issues 2-4

Workshop No. 4
December 11, 2019

Safety – Roles & Responsibilities

Call
911

Ann Springgate

CPR
AED
First Aid

CPR: TBD
AED:
Sam Kang
First Aid:
Maria Litos

Meet & Greet
Safety
Personnel

Doug Karpa

Duck
Cover &
Hold

Sweep the Room

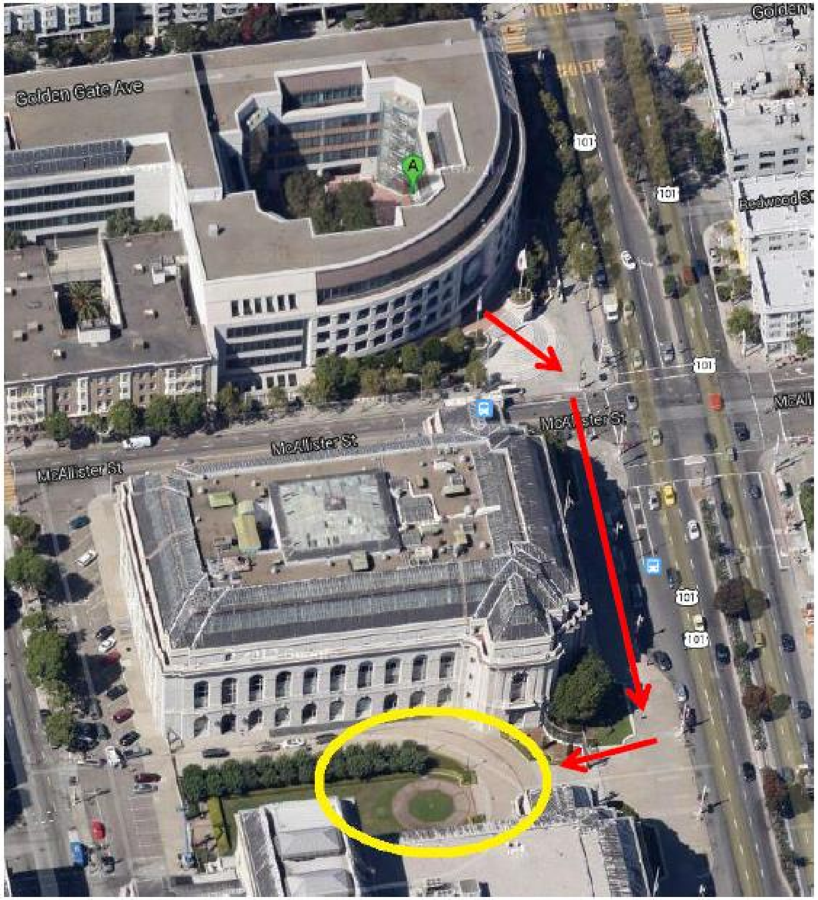
Shagun Tougas

Silence Cell Phones
Get OUT
Hide OUT
Keep OUT
Take OUT

Safety – Evacuation Procedure

In the event of an emergency evacuation:

- Cross McAllister Street
- Gather in the Opera House courtyard down Van Ness, across from City Hall.



WiFi Access

Network: CPUCguest

Username: guest

Password: cpuc113019

Agenda

- Safety and Status Check
- Issue 1 - Recap and Refinement of Proposals
  - Resource Adequacy Updates
  - RPS and GHG-Free Energy Updates
  - Other Updates
- Issue 2 – Active Management of IOU Portfolios
- Issue 3 – Potential Adoption of Additional Standards for Active Portfolio Management and the Transition
- Issue 4 – New or Modified Shareholder Responsibility
- Next Steps

Working Group Three – Issues to be Discussed
Scoping Memo R.17-06-26

1. What are the *structures, processes, and rules governing portfolio optimization* that the Commission should consider to address excess resources in utility portfolios? How should these processes/rules be structured to be compatible with the ongoing IRP and RA program modifications in other proceedings?

2. What standards should the Commission adopt for *more active management of the utilities' portfolios in response to departing load* in the future to minimize further accumulation of uneconomic costs?

3. If the Commission were to adopt standards for more active management of the utility portfolios, *how should the transition to new standards occur* (e.g., timeframe, process, etc.)?

4. Should the Commission *consider new or modified shareholder responsibility for future portfolio mismanagement*, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards? Are ERRA or GRC proceedings the appropriate forums to address prudent management of portfolios?

Recap and Refinement of Issue 1 Proposals

PCIA Phase 2 - Working Group 3

Recap: Allocation & Market Offer Process & Products

- The Co-Leads presented four proposals at the previous WG3 Workshop

	Local RA	GHG-Free	RPS	System / Flex RA
Pro rata vintage share	Peak-Load	Forecasted Annual Load Share	Forecasted Annual Load Share	Peak-Load
Allocation	Mandatory	Voluntary (all or portion)	Voluntary (all or portion)	Voluntary (all or portion)
Market Offer	N/A	N/A	Long-term and short-term bundled RPS	Monthly or Annual

Recap: Local RA and GHG-Free Energy Proposals

- Local RA Allocation Proposal
  - Mandatory allocation via a CAM-like mechanism, but may be traded*,**
    - Commercial supports voluntary allocation with auction of unallocated RA
  - Multi-year forward allocations track Local RA obligations
  - System and Flex RA from Local resources follows Local RA allocation
  - Allocated products receive a benchmark value of $0 in PCIA mechanism
- Voluntary GHG-Free Energy Allocation Proposal
  - Voluntary option to accept all or none of Nuclear or Non-Nuclear pools of GHG-free energy
    - Unallocated energy is re-allocated amongst LSEs accepting allocation
    - Commercial Energy supports voluntary allocation of any portion of pools, with unallocated energy being auctioned off
  - IOU continues to serve as Scheduling Coordinator for energy
  - No change to PCIA rates, as GHG-free energy receives no additional benchmark value

* SCE is neutral to trading of Local RA after an allocation, but if permitted, does not believe IOUs should be required to manage the process

** CalCCA will not support any allocation scheme that does not allow trading of allocated products

Recap: Voluntary Allocation & Market Offer Proposal for RPS and System/Flex RA

- LSEs can make an annual election to accept or decline an allocation of their vintaged share of available PCIA-eligible RPS energy & System/Flex RA
- IOU will offer to the market the unallocated RPS energy and/or System/Flex RA
- IOU will continue to manage the PCIA portfolio, performing the following functions:
  - Schedule energy into the CAISO market;
  - Show RA through a CAM-like mechanism;
  - Transfer bundled RECs to benefiting LSEs; and
  - Provide information to certify RPS energy for Power Content Label
- IOU may continue to perform portfolio optimization activities outside of Voluntary Allocation and Market Offer mechanism

Updates to Prior RPS Proposal

PCIA Phase 2 - Working Group 3

Update to RPS & GHG-Free Allocation Structure

- Co-Leads propose to use forecasted, vintage, load shares for determining allocation percentage; quantities will be determined by actual generation

- Co-Leads previously proposed to allocate RPS and GHG-free energy on an actual, vintaged, annual load share basis
  - Concerns that load share uncertainty resulted in additional complexity, particularly for market offer process

Update to RPS Long-Term Attribute Preservation

- Stakeholder feedback supported the position that to preserve long-term attribute preservation, LSEs must accept allocations for 10+ years
- CalCCA and SCE propose that in order for an LSE to receive the "long-term" benefits from RPS allocation, they must elect to receive their allocation share through the life of their vintage*
  - LSEs that opt for short-term allocation will not receive long-term benefits
  - To receive long-term credit, the longest RPS contract in their vintage must have a remaining term of at least 10 years
    - Excluding UOG and evergreen contracts to extent they exist
  - Allocations count as long-term regardless of underlying contract terms if allocation is accepted at LSE's first election opportunity
- LSEs taking allocations may be required to enter into Commission pre-approved contract/confirm
- Quantities available for allocation are subject to any IOU portfolio optimization

*Must commit to the longest term of any single contract in the vintage

Update to RPS Voluntary Market Offer Structure

- Annually, the IOU will offer to sell all unallocated RPS energy for a term beginning in the prompt year
  - Long-term sales will be offered up to a 35% cap applied to the lesser of LSE's (a) total allocation share or (b) sales election
    - RPS sales will convey long-term attributes only if sold for 10+ year terms
  - Long-term sales amounts will be based upon the LSE's forecasted minimum allocation for the term of the long-term offer
- The co-leads propose an annual report (new or existing) be published by Energy Division summarizing results of the auctions and potential impact of the cap on long-term sales on realized value
- Recommend a reassessment of the cap by CPUC after 2 years

Refinement of System/Flex RA Proposal

PCIA Phase 2 - Working Group 3

Proposal for Allocating System and Flexible RA

- RA allocation process
  - Resources by attributes pooled together for distribution similar to current CAM process
  - Distribution shown on the LSE Allocations tab of CPUC RA template
- Secondary Trading of RA allocations
  - LSEs can trade their RA allocations in a secondary market outside of VAMO
  - Trade amounts identified on the same LSE Allocations tab
  - Trade process is based on modifications to existing CPUC RA template
  - After initial allocation, no further IOU involvement is required
- Co-leads may consider further refinement

LSE Allocation Tab Example

Month	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
SP26 CAM Capacity	0	0	0	0	0	0	0	0	0	0	0	0
NP26 CAM Capacity	50	50	50	50	50	50	50	50	50	50	50	50
RA Allocation North System	12	12	12	12	12	12	12	12	12	12	12	12
RA Allocation South System												
RA Allocation LA Basin												
RA Allocation Big Creek-Ventura												
RA Allocation Sand Diego-IV												
RA Allocation Bay Area	11	11	11	11	11	11	11	11	11	11	11	11
RA Allocation Fresno	4	4	4	4	4	4	4	4	4	4	4	4
RA Allocation Sierra	3	3	3	3	3	3	3	3	3	3	3	3
RA Allocation Stockton	2	2	2	2	2	2	2	2	2	2	2	2
RA Allocation Kern	1	1	1	1	1	1	1	1	1	1	1	1
RA Allocation Humboldt	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
RA Allocation NCNB	2	2	2	2	2	2	2	2	2	2	2	2
RA Allocation Flex												
NP26 Condition 2 RMR	5	5	5	5	5	5	5	5	5	5	5	5
SCE Preferred LCR Credit	0	0	0	0	0	0	0	0	0	0	0	0

Then we can have a part II of Table 8 that shows a transfer to LSE and net any allocations. ↓

Net Monthly Position	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
RA Allocation Sierra example	4											
RA Allocation NCNB example	1											
RA Allocation Bay Area example	7											
RA Allocation Humboldt	1.5											
List each of the allocations												

Likely we can't unbundle Flex so we may need each of the RA Allocation categories to be with or sans Flex (just adding it here for simplicity of the illustration

Monthly Trades	Product	LSE	Volume
LCPSF	Sierra		1
CRLL	NCNB		-1
TPES	Bay Area		-4
CRLL	Humboldt		1

Example for January only

Other Issue 1 Refinements

PCIA Phase 2 - Working Group 3

Spring System / Flex RA Market Offer

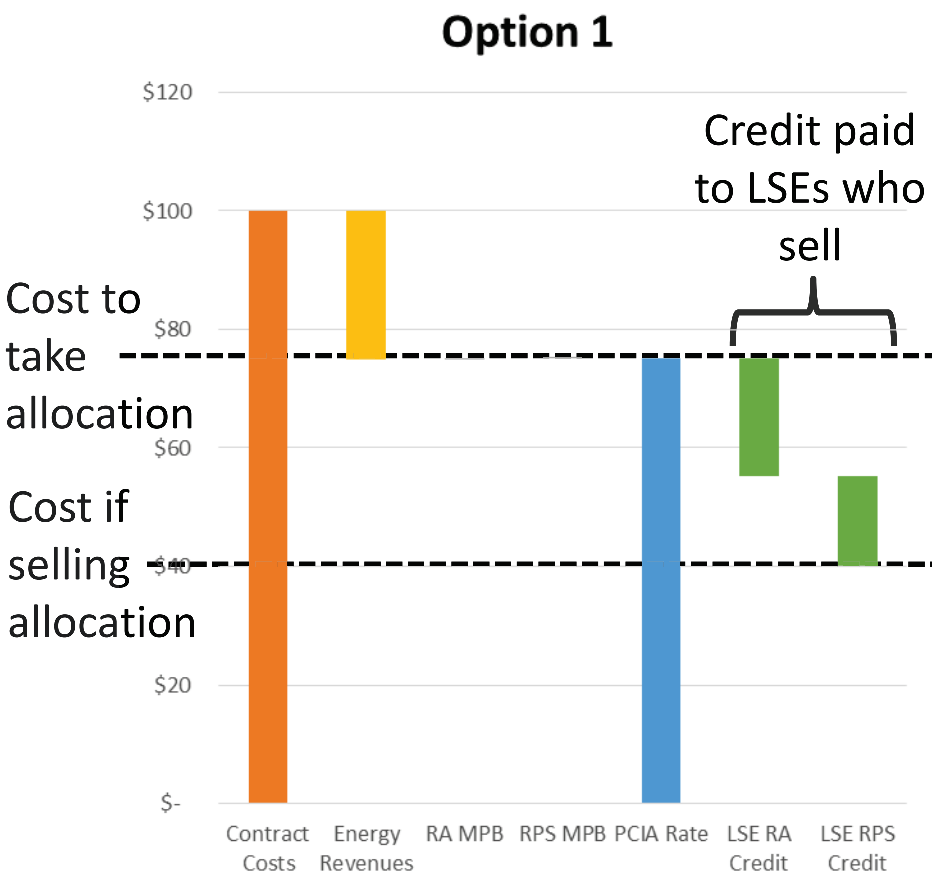
- Under the existing schedule for determining final LSE RA obligations, there is only a short window for procurement between receiving RA obligations and the year-ahead RA showing
- In order to relieve this pressure and maximize the RA value in the Market Offer process, the co-leads propose adding an additional System/Flex RA Market Offer in the spring of each year
- Volume available in the spring Market Offer would be determined as follows
  - LSE's would have an early opportunity to decline their allocation for the following year in Q1 (e.g., decline in Q1 2020 for allocation in 2021)
  - For any volumes declined for allocation in Q1, a percentage* of the declined allocation would be made available
  - LSE's who do not decline their allocation in Q1 will still be able to make their allocation decision in the fall
  - The fall Market Offer will include unsold volumes from the spring market offer and any unallocated RA based on fall allocation decisions

* Co-leads are considering 50%-75% depending on timing of early market offer

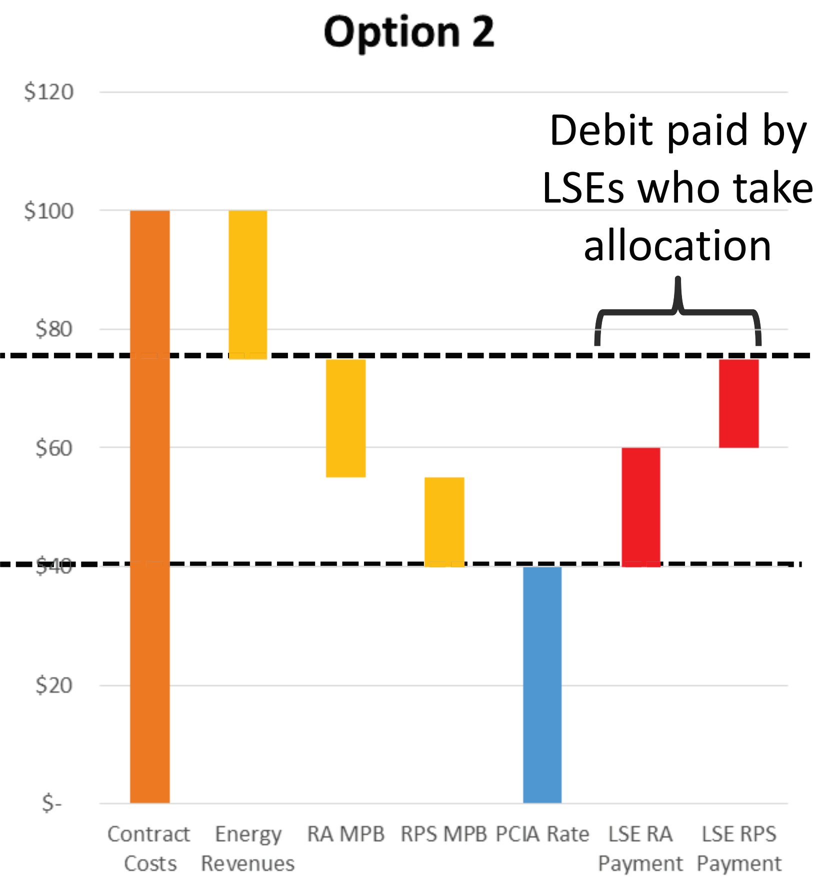
PCIA Ratemaking Structures - Recap

- Seek to minimize complexity of PCIA ratemaking and billing
- All customers in the same vintage pay the same PCIA rate
- Option 1:
  - All customers pay full resource costs, less CAISO revenues
  - Product types available for allocation receive $0 value
  - LSEs wishing to sell products receive a direct payment from the IOU according to the LSEs' proportional share of the realized sales revenues
- Option 2:
  - All customers pay full resource costs, less CAISO revenues, less the quantity of products in portfolio multiplied by PCIA product market price benchmark ("MPB")
  - LSEs wishing to take allocations must pay the PCIA product MPB for all products accepted as an allocation

PCIA Ratemaking Proposal Comparison



Assumes LSEs take allocation
Credits LSEs who sell allocation



Assumes LSEs sell allocation
Charges LSEs who take allocation

Long-Term Contracts and Rate Making Option 2

- Long-term sales can create the potential for cost shifts with Rate Making Option 2 when using the Market Price Benchmark approach, as adopted in Track 1, to set price that parties taking allocations should pay
  - MPB does not factor in sales that occur prior to N-2 period
  - Co-leads initially outlined an alternative "auction price benchmark" that addressed issue, but many parties have expressed interest in retaining current MPB construct
- CalCCA and SCE propose that the allocation price should factor in the weighted average price of historical* long-term transactions that occurred in periods prior to those considered in the MPB
  - Weighted average based upon quantity of RECs sold under long-term contracts in historical* periods that are still delivering vs. volumes sold in periods included in MPB
  - Conceptually, it can be thought of as the allocation participants having locked in a similar percentage of long-term pricing as represented in sales processes
  - Result is that parties taking allocations pay approximately their allocation percentage share of total contract costs

* Transactions entered into prior to N-2

Issue 2: Active Management of IOU Portfolios

PCIA Phase 2 - Working Group 3

IOU Portfolio Management Activities

- IOUs manage their portfolios on a short-term and long-term basis, consistent with AB 57, as well as their BPP and RPS Plans
- Each IOU currently maintains a team of professionals dedicated to managing its contract portfolio. Responsibilities include:
  - Ensuring terms and conditions are complied with;
  - Resolving disputes with counterparties; and
  - Identifying additional opportunities for cost reduction and value improvement
- The opportunity to modify a contract typically arises under three circumstances:
  - Either party requests a contract modification;
  - Buyer and/or seller identify an opportunity for a mutual benefit; or
  - Counterparty fails to perform
- Every contract, situation, and counterparty is unique
- Portfolio optimization activities require judgement, consideration of current market conditions, adherence to policies and Commission rules, and negotiation to be successful
  - Commission has imposed a reasonable manager standard for IOU portfolio management activities, as prescribed metrics cannot account for diversity of situations

Examples of Existing IOU Portfolio Optimization Activities

1. Enforcing rights due to events of default
2. Contract buy-outs
3. Change of contract term
4. Adjusting the contract capacity or facility design
5. Managing project design and timelines
6. Modifying site locations and/or on-line dates
7. Monitoring performance and enforcing compliance
8. Modifying equipment requirements
9. Incorporating economic curtailment rights
10. Managing force majeure claims
11. Reducing collateral requirements in exchange for an upfront payment
12. Other unique opportunities

Portfolio Management – Contract Assignments and Buy-Outs

- In addition to existing portfolio optimization practices, the co-leads propose to add an RFI process for contract assignments and buy-outs
- The process would have two parts
  - A process where IOUs would connect interested sellers with LSEs or other market participants who are interested in taking assignment of contracts from the IOU portfolio
  - An opportunity for sellers to propose contract-buy-outs
  - Process will be held annually for the first two years; after which the Commission to consider whether the process should be modified or continued
    - If continued, the process will be run every other year
- Resulting assignments or terminations would completely remove the contracts from the IOU portfolio
- IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards
  - Any accepted offers will be subject to approval by the CPUC
- Details related to RFI process are still being discussed by co-leads

Contract Assignment Process Proposal

IOUs notify generators meeting certain criteria* of solicitation → Interested generators identify key conditions required for consideration of assignment → IOUs notify market of interested generators and preconditions → LSEs notify IOUs of interest in any contracts and ability to meet pre-conditions → IOUs connect interested sellers with qualifying LSEs, who negotiate an assignment of the contract or new contract

*Exclusions under consideration:
- Contracts priced below 115% of the Market Price Benchmark
- Contracts that if assigned will result in a shortfall in IOU RPS compliance

Issue 3: Transition to New Standards, if Identified

Issue 4: Shareholder Responsibility

PCIA Phase 2 - Working Group 3

Proposed Increase Reporting Standards

- The IOUs provide a variety of reporting of different events in their ERRA filings but the ERRA reporting may not be the same across all IOUs
  - Increased reporting
    - IOUs to report material events of defaults and any termination rights in ERRA compliance filings and any actions taken with respect thereto
    - Report cost savings from active portfolio management

Next Steps

Next Steps

- Co-Leads are seeking feedback on concepts presented by 12/20
  - Please submit informal comments through CPUC Service List

- Working Group 3 Next Steps:
  - Review informal comments received from workshop participants and refine proposals
  - Continue preparation of Final Report

- Upcoming Deliverables:
  - Final Report due January 30, 2020
  - Stakeholders comment on Final Report due 10 working days after filing Final Report [February 13, 2020] – to be confirmed by Commission
  - Commission Decision expected Q2 2020

Appendix E

INFORMAL COMMENTS TO FOURTH WORKSHOP PRESENTATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS INFORMAL COMMENTS ON PCIA WORKING GROUP 3 MEETING #4

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
Telephone: (510) 778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

20 December 2019

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

**ALLIANCE FOR RETAIL ENERGY MARKETS PCIA WORKING GROUP 3
WORKSHOP #4**

The Alliance for Retail Energy Markets ("AReM") appreciates the opportunity to provide these informal comments on topics discussed in Workshop #4 of Working Group #3 ("WG3"), conducted on 11 December 2019 in San Francisco, California. AReM's comments below are focused on Local Resource Adequacy ("RA") allocation, rules for counting renewable resources as long-term, concerns that consideration of active management of Investor Owned Utility ("IOU") portfolios is incomplete, and remaining clarifications needed with respect to the PCIA calculation.

1. Local RA Allocation Should be Voluntary and Not Mandatory; If Mandatory, Only Former PG&E Other Resources Should Be Mandatory

While accepting an allocation of all other resource attributes (System/Flex RA, RPS, and GHG-Free resources) is voluntary for the LSEs offered the attributes, WG3 continues to propose that LSEs must accept Local RA allocations – that is, both the IOU offers of the Local RA attributes and the LSE acceptance of the offers – is mandatory. AReM does not believe that there is a need to treat Local RA differently from other resource allocations and asks the WG3 leads develop an approach where accepting a Local RA allocation is also on a voluntary basis. In addition, mandatory allocation acceptances run counter to Commission direction for what the Working Groups should consider[1], as outlined by DACC in its comments of 9 August.

Under the WG3 proposal, entities not needing their full allocation could sell to others, but that approach just exchanges one problem for another. Much like the IOUs today, there is no guarantee that those entities (i) will sell any excess they have, (ii) will have time to sell any excess they have given when the allocation occurs, (iii) will not keep the excess as a "buffer" for "uncertainty", or (iv) will not use allocated Local for System or Flex RA needs. Having a voluntary allocation process reduces these concerns as only entities with a need for the resources will pay for the allocation.

In addition, many LSEs may not need their allocation, especially in areas with increasing levels of CAM allocations. For example, all non-IOU LSEs are seeing their LA Basin Local RA requirements move considerably lower beginning in 2022 due to new CAM allocations. A mandatory allocation could then force non-IOU LSEs to take and pay through the PCIA for resources that they do not need.

During Workshop #4, it was stated by the WG leads that the mandatory acceptance of Local RA allocations approach came from a desire by the Northern California CCAs to have resources in the former "PG&E Other" locations[2] allocated to match specific needs without having an auction of any unallocated resources. If the WG leads and parties agree that this is the main reason for a mandatory allocation and if a voluntary allocation of Local RA is not preferred, the leads should consider a mandatory allocation of ONLY former PG&E Other Local RA and no

[1] D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at p. 96.
[2] Former PG&E Other Local RA was disaggregated per D.19-02-022 into the Stockton, Sierra, North Bay/North Coast, Kern, Fresno, and Humboldt local capacity areas.

other Local RA mandatory allocations. All other Local RA allocations besides those in the former PG&E Other locations would then be done solely through a voluntary process.

2. Greater Active Management of IOU Portfolios

One of the key elements of minimizing PCIA related charges and optimizing utility portfolios that was to be included in WG 3 was active management of IOU portfolios. This entails contract assignments and buy-outs that would permanently remove the contractual resources from the utility portfolio and get the IOU resources more in line with the amount of load they are serving and expected to serve over the long term. In AReM's opinion this should have been the highest priority action of this WG as these mechanisms are the best way to actually "right size" the utility portfolios. "Right sizing" the IOU portfolios is only genuinely accomplished by getting portfolios in line with the amount of load being served. The markets for energy and capacity will work better if the IOUs return their excess to the market so that entities who need the supply can contract for it. There is no need for the IOUs to hold an "excess" or "buffer"; IOU customers will be made whole through the PCIA via payment for any above market contract costs, and any needed future procurement will be at the market price.

At Workshop #4, the co-leads described a proposal for the IOUs to conduct Requests for Information ("RFI"s) that would lead to contract assignments and buy-outs by connecting interested sellers with market participants interested in taking contract assignments or by allowing sellers to negotiate buyouts. The Workshop #4 presentation stated that the co-leads will continue to discuss the details of how an RFI process may work, but no details have been established as of yet. Since the final report of WG 3 is due by the end of January, this important topic is unlikely to be seriously vetted with interested parties, with important topics such (i) firm commitments or targets for divestitures, (ii) ensuring ensure that the parties to the existing contracts will be treated fairly and kept whole, and (iii) how the remaining stranded costs associated with divested contracts will be processed through the PCIA not discussed amongst stakeholders. To ensure that this important work gets done, AReM urges that the final WG 3 report develops a more concrete structure for divestment of excess IOU procurement, including discussion the topics listed above.

3. Only Long Term Renewable Contracts Should Receive Long Term Procurement Credits

The WG3 leads proposed in Workshop #4 that an entity that commits to take their Renewable Portfolio Standard ("RPS") allocation share through the life of their vintage will receive long-term procurement credits for all resources in that vintage provided that the longest RPS contract in the vintage has a remaining term of at least 10 years. AReM is concerned that it expands the quantity of RPS energy in the utility portfolio that qualifies for meeting the long-term contracting requirement to resources that are not actually long-term. If that is the case, AReM objects to this, as it could represent a significant change to the RPS long-term contracting rules. AReM members have already begun their procurement of resources for Compliance Period 4 from resources that meet the current definition of long-term RPS. Changing the rules now will diminish the values of these investments and penalize existing long-term procurement actions.

The WG3 leads stated in the 11 December workshop that the number of RPS contracts in each vintage with contract lives shorter than 10 years is small. AReM requests that the WG leads provide data on the number of short-term contracts which would now be classified as long-term by vintage if this proposal was to be applied.

4. Clarification of Use of Long Term Renewable Contracts in the PCIA Calculation

In the 11 December workshop, the WG leads proposed using "Option 2" for PCIA calculation with a new modification that will factor in the weighted average price of historical long-term transactions that occurred in periods prior to those considered in the RPS Market Price Benchmark ("MPB"). AReM's interpretation of the proposal is that the RPS MPB will not just include "reported prices from purchases and sales of renewable energy...during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n)" (per D.19-10-018), but also include the sales price of any long-term contracts that are operating in year n. As an example, sales of a long-term RPS contract in 2020 with a term that runs through 2030 would have its sales price included in the MPB for years 2022-2030. AReM would like confirmation that this example matches the intent of the proposal, and would also like answers to the following questions:

- Will the proposal only apply to resources sold after a decision in WG3? Or will any long-term resource sold from the IOU portfolios in the past now be included in the MPB calculations?
- Would this modified MPB be used to calculate the RPS Adder used in the calculation of the PCIA for all entities, or only for the cost paid by an entity that voluntarily takes a long-term RPS allocation?
- How will this impact the MPB relative to the current RPS MPB? Please provide an estimate given recent transaction costs and recent MPB calculations.

AReM thanks the WG leads for their efforts and looks forward to a final report that addresses all the issues above and those in past sets of informal comments that have not been addressed.

Respectfully submitted,

Scott Olson, Director, Western G&R A
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
510.778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

20 December 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COALITION OF CALIFORNIA UTILITY EMPLOYEES
INFORMAL COMMENTS ON PCIA PHASE 2 – WORKING GROUP 3, WORKSHOP 4

December 20, 2019

Rachael E. Koss
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080
(650) 589-1660 Telephone
(650) 589-5062 Fax
rkoss@adamsbroadwell.com

Attorneys for Coalition of California Utility Employees

1011-1574j

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COALITION OF CALIFORNIA UTILITY EMPLOYEES
INFORMAL COMMENTS ON PCIA PHASE 2 – WORKING GROUP 3, WORKSHOP 4

The Coalition of California Utility Employees (CUE) appreciates the opportunity to provide comments on the December 11, 2019, PCIA Working Group 3, Workshop 4 on portfolio optimization and auction and allocation. CUE's comments focus on the Working Group's proposal for IOUs to allocate RPS-eligible resources.

Slide 12 of the Working Group's presentation proposes that an LSE be able to receive a portion of or its entire RPS-eligible procurement obligation as an allocation from an IOU. The proposal contemplates that if the allocation includes just ***one*** contract with at least 10 years remaining, the ***entire*** allocated portfolio would count towards the LSE's RPS long-term compliance obligations. The Working Group's proposal is inconsistent with the RPS statute.

Public Utilities Code section 399.13(b) requires at least 65% of an LSE's RPS procurement to be from its contracts of at least 10 years. The Working Group's proposal opens the door for LSEs to circumvent this requirement and violate the law by packaging one long-term contract with any number of contracts that have less than 10 years left on them. However, the Commission does not have authority to modify the RPS long-term contracting requirement.

The Working Group should revise its proposal to eliminate any option for an LSE to satisfy its RPS long-term contract obligations with anything less than 65% of its contracts that are 10 years or longer.

Dated: December 20, 2019

Respectfully submitted,

/s/

Rachael E. Koss
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080
(650) 589-1660 Voice
(650) 589-5062 Fax
rkoss@adamsbroadwell.com

Attorneys for Coalition of California Utility Employees

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

**INFORMAL COMMENTS OF
NEXTERA ENERGY RESOURCES, LLC ON PCIA WORKING GROUP 3,
WORKSHOP #4**

NextEra Energy Resources, LLC ("NextEra") provides the following informal comments on the portfolio optimization activities outlined on slides 24-26 in the presentation from the Workshop held on December 11, 2019. This includes, but is not limited to, the Request for Information (RFI) contract assignment proposal. NextEra appreciates the efforts of the co-leads, Southern California Edison Company, Commercial Energy, and California Community Choice Aggregation ("CalCCA"), and of the many others who have participated in this Working Group.

I. INFORMAL COMMENTS

NextEra continues to hold that in developing any portfolio optimization approach, parties should focus, as the Working Group sought to do at the outset, on the Commission's guiding principles identified in the Phase 1 Scoping Memo and Ruling of Assigned Commissioner, dated September 25, 2017 ("Phase 1 Scoping Memo"). In particular, NextEra supports the Commission's guidance that any methodology adopted through this process (i) should be consistent with California statutes, Commission decisions, energy policy goals, and mandates, and (ii) should respect the terms of existing power purchase agreements ("PPA") between power suppliers and IOUs.[1]

[1] Strawman Proposal at 3; Phase 1 Scoping Memo at 14 (establishing that any PCIA methodology adopted by the Commission "should respect the terms of existing power purchase agreements between power suppliers and IOUs").

Consistent with these principles, any portfolio optimization proposal, such as the RFI contract assignment process, should ensure that the commitments under existing renewable generation PPAs are preserved, and recognize that all counterparties have a legal right to reject re-assignment of their contracts. This is critical to ensuring market stability in the state to encourage continued development of renewables in order to meet California's clean energy and net-zero carbon mandates.

Developers of wind, solar, and other renewable electricity generation resources have made significant investments to build new generating facilities in California that produce electricity to meet increasing milestones under the California RPS. IOUs' execution of long-term PPAs for new renewable projects — and the Commission's approval of and assurance of rate recovery for those PPAs — provided a critical foundation that facilitated financing and construction of significant new renewable generating resources in California. In particular, the PPAs contain terms and conditions (including terms related to price, term, termination, assignment, change of control, event of default, creditworthiness, and consent) that are essential to continuing renewable generators' financing arrangements. Therefore, any portfolio optimization mechanism that contemplates adjustments to existing contracts, including but not limited to: contract re-assignment, buy-out of contracts, change of contracts terms, or adjusting the contract capacity or facility design, should be implemented in a manner that recognizes that PPA sellers may not agree to modifications of their existing contractual provisions.

The RFI contract assignment proposal from the December workshop presentation contemplates:

- IOUs would connect interested sellers with load-serving entities or other market participants who are interested in taking assignment of contracts from the IOU portfolio.
- Sellers would have an opportunity to propose contract-buy-outs.

- The process will be held annually for the first two years, after which the Commission would consider whether the process should be modified or continued.
- If continued, the process will be run every other year.
- IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards.
- Any accepted offers will be subject to approval by the Commission.

It should be recognized, however, that each counterparty has a right to accept or reject changes to contract terms, or re-assignment or buy-out of its contract. Failure to do so would be in conflict with the Commission's guiding principles described above and with the current law. As a general matter, assignment of an existing PPA would require the consent of the seller (and most likely, its lenders) before any assignment can be completed. Any method such as the RFI re-assignment proposal must include a process that recognizes the PPA sellers' contractual right to consent to any such assignment or transfer, as well as requirements that the terms of the original PPA be maintained.

On slide 26 of the presentation, the co-leads allude to the fact that "interested" generators would be given the opportunity to "identify key conditions required for consideration of assignment." NextEra agrees that such a requirement must be a part of any such process at a minimum. As an initial step, the counterparty must first be consulted and agree to consider entering this process. The counterparty would also reserve the right to ultimately deny adjustment of contract terms, re-assignment, or a buy-out of its contract.

The Working Group 3 co-leads state that details for this process are still being discussed. As an impacted party, NextEra respectfully requests that the co-leads provide more detail on this proposal and an additional opportunity for comment on those further details before including the RFI contract assignment proposal in the final report, currently scheduled to be submitted on January 30.

II. CONCLUSION

NextEra appreciates the opportunity to provide informal comments here. The RFI contract assignment proposal and the other potential optimization activities listed on slide 24 are of serious consequence to developers and other counterparties to the contracts on which the state relies. Serious thought and effort must be put into any proposal that contemplates adjustment of contract terms, or re-assignment or buy-outs of these contracts. Neither the presentation from the December 11, 2019 workshop, nor the workshop itself, have provided sufficient information on these concepts. NextEra strongly encourages this working group to more fully develop this proposal before inclusion in its final report.

Dated: January 22, 2020

Respectfully submitted,

/s/ Lisa A. Cottle

Lisa A. Cottle
Winston & Strawn LLP
101 California Street, 35th Floor
San Francisco, CA 94111-5840
Telephone: (415) 591-1579
Facsimile: (415) 591-1400
Email: lcottle@winston.com

Tracy C. Davis
Senior Attorney
NextEra Energy Resources, LLC
5920 W. William Cannon Dr., Bldg. 2
Austin, TX 78749
Telephone: (512) 236-3141
Facsimile: (512) 236-0484
Email: tracy.c.davis@nexteraenergy.com

Attorneys for NextEra Energy Resources, LLC

Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-1584
www.publicadvocates.cpuc.ca.gov

THE PUBLIC ADVOCATES OFFICE'S COMMENTS
ON *PCIA PHASE 2 WORKING GROUP 3*

R.17-06-026

Submitted by	**Organization**	**Date Submitted**
Mea Halperin Senior Analyst Phone: (415) 703-1368 Email: Mea.Halperin@cpuc.ca.gov Sonya Ziaja Senior Analyst Phone: (415) 703-1271 Email: Sonya.Ziaja@cpuc.ca.gov Public Advocates Office California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102	Public Advocates Office – California Public Utilities Commission	December 20, 2019

The Public Advocates Office submits the following informal comments in response to the December 11, 2019 Fourth Workshop for the Power Charge Indifference Adjustment (PCIA) Working Group Three: Portfolio Optimization and Cost Reduction, Allocation, and Auction. This workshop largely summarized the ongoing scoping issues discussed during the previous three workshops, and the co-chairs proposed some new recommendations. Of these recommendations, the Public Advocates Office opposes imposing the PCIA cap during the portfolio optimization process, as well as changing the Energy Resource Recovery Account (ERRA) reporting requirements outside of the ERRA proceeding. The Public Advocates Office also opposes two proposals related to the sunset of the PCIA and enforcement of reporting requirements submitted by the Protect Our Communities Foundation (POC) in its November 4, 2019 filing.[1]

Application of PCIA Cap During Portfolio Optimization Process

According to the PCIA Phase 1 Decision, the PCIA cap is set at 0.5 cents/kWh more than the prior year's PCIA (differentiated by vintage), and any PCIA amount that exceeds the cap will be tracked in a separate balancing account for recovery from departing load customers at a future date.[2] In the event that an investor-owned utility (IOU) projects the PCIA will exceed 10% of its forecast PCIA revenues and will not self-correct, the IOU must submit an application proposing a revised PCIA rate that will bring, and maintain, the account balance below 7% until January 1 of the following year.[3]

Although the portfolio optimization process runs the risk of causing the PCIA to spike, it is not reasonable to implement the PCIA cap for the costs incurred during this process. While stable rates would benefit departing load customers, a cap on the PCIA results in short-term cost spikes for bundled service customers. This is because any PCIA amount not paid by the departing load customers must be paid in the interim by bundled service customers until the balance is repaid to bundled service customers, with interest.[4] While this may be reasonable for PCIA overages incurred during regular energy market transactions, the scale of the portfolio optimization market offer transactions places bundled service customers at risk of paying significantly increased rates in the short-term which would result in rate instability for bundled service customers. Furthermore, if the portfolio optimization transactions activate the PCIA trigger mechanism, the revised rate that would bring the PCIA account balance below 7% may lead to departing load rate spikes anyway.

Instead, the parties must approach portfolio optimization in a similar manner to prepayment; that is, a departing load party must pay up-front for resources offered in the voluntary market, and seek cost recovery from its customers outside of the PCIA. Portfolio

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[1] POC proposes (1) that the PCIA sunset in 5 years and (2) all proposals include automatic enforcement and shareholder responsibility mechanisms. (Protect Our Communities Foundation's Proposals for Portfolio Optimization [POC Proposal], November 4, 2019.)
[2] D.18-10-019, Ordering Paragraph (OP) 9, p. 162.
[3] D.18-10-019, Ordering Paragraph (OP) 10, pp. 163-164.
[4] D.18-10-019, p. 86.

optimization is a voluntary process, and bundled service customers must not be forced to pay the short-term excess costs from elective market transactions.

Increased ERRA Reporting Requirements

The co-chairs propose that the IOUs report additional information in their annual ERRA filings, including "material events of defaults and any termination rights in ERRA compliance filings" and "cost savings from active portfolio management."[5] This recommendation is inappropriate for the PCIA proceeding; any changes to ERRA compliance requirements must be addressed within the ERRA proceeding through a Petition for Modification, or other similar mechanism, with ample opportunity for parties to participate and comment.

While the co-chairs are correct that the information in the IOUs' ERRA Compliance filings "may not be the same across all IOUs,"[6] this is because the IOUs engage in different types of transactions in a given Record Period, and the activities they report vary based on the status of their contracts and the events that took place during the Record Period. However, the reporting *requirements* are the same across all IOUs. The IOUs are already required to report the details of their contract administration activities in a given Record Period, including "material events of defaults and any termination rights,"[7] as well as the management of their utility-owned generation (UOG) resources,[8] least-cost dispatch,[9] greenhouse gas (GHG) compliance obligations,[10] and accounting activity.[11] In short, ERRA Compliance is complex, long-running, and the proceedings often involve multiple parties. Any changes to the ERRA process must be proposed and addressed within the ERRA framework.

Protect Our Communities' Proposal

[5] PCIA Phase 2 Working Group 3, Workshop No. 4 Presentation, December 11, 2019, slide 28.
[6] PCIA Phase 2 Working Group 3, Workshop No. 4 Presentation, December 11, 2019, slide 28.
[7] D.11-10-002.
[8] D.11-10-002.
[9] D.05-01-054, D.15-05-005, D.15-05-006, D.15-05-007.
[10] D.12-04-046
[11] D.02-10-062.

POC submitted a proposal for portfolio optimization on November 4, 2019, which includes a plan to sunset the PCIA in five years.[12] The Commission already considered, and rejected, the notion of a PCIA sunset provision in Phase 1, as discussed in D.18-10-019:

> [W]e agree … that [Public Utilities Code] Section 366.2(f)(2) bars the Commission from sunsetting CCA customer obligations vis-à-vis "the expiration of all then existing electricity purchase contracts." We also agree … that a sunset provision will reduce incentives for parties to actively participate in any allocation or auction process that may take place in the second phase of this proceeding.[13]

These reasons for rejecting the PCIA sunset are still applicable.

Additionally, POC raises several proposals for "automatic enforcement of the co-chair's allocation and auction proposal."[14] Specifically, POC proposes that if IOUs miss reporting deadlines, bundled and unbundled customers would automatically receive bill credits within 60 days of the missed deadline, paid for by the IOU's shareholders, "without the need for any Commission action."[15] While the Public Advocates Office favors oversight of the IOUs to ensure just and reasonable rates, it does not support the enforcement mechanisms proposed by POC.

At its core, POC's proposal is primarily concerned with oversight of IOU energy procurement to prevent waste.[16] However, compliance mechanisms already exist within the Commission's procurement framework – such as the ERRA forecast and compliance proceedings,[17] the integrated resource planning (IRP) process,[18] and utility-scale Request for Offers (RFO) and solicitations[19] – to ensure that IOUs' reports and actions are timely and transparent. Therefore, the Public Advocates Office recommends that the working group co-chairs reject the enforcement aspects of POC's proposal.

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[12] POC Proposal, pp. 3-5.
[13] D.18-10-092, p. 82.
[14] POC Proposal, p. 2, 6-7.
[15] POC Proposal, p. 6.
[16] POC Proposal, p. 1 (e.g., "If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.").
[17] https://www.cpuc.ca.gov/General.aspx?id=10430
[18] https://www.cpuc.ca.gov/irp/
[19] https://www.cpuc.ca.gov/Utility_Scale_RFO/

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

INFORMAL COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #4

M. GRADY MATHAI-JACKSON
KRISTIN D. CHARIPAR

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: December 20, 2019

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**INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #4**

Pacific Gas and Electric Company ("PG&E") provides the following informal comments on the Power Charge Indifference Adjustment ("PCIA") Phase 2, Working Group Three, Workshop #4 held on December 11, 2019 (the "Workshop"). PG&E lauds the work by Southern California Edison Company ("SCE"), the California Community Choice Association ("CalCCA") and Commercial Energy (collectively, the "Co-Leads"), to develop an initial framework for the allocation of system, local and flexible resource adequacy ("RA"), greenhouse gas ("GHG")-free, and renewables portfolio standards ("RPS") attributes, and appreciates the ability to provide comments.

As described below, PG&E describes below its concerns with certain elements of the revised proposal and offers general feedback on the market offer component of the proposal. In particular, these comments address PG&E's recommendations on the following issues:

1. PG&E supports a simpler mechanism for allocating out the costs and benefits to all customers; if not, Co-Leads should clarify proposals;
2. Further clarification of the existing proposal, including real-world examples, is necessary to determine if implementation is feasible;
3. The ratemaking challenges associated with the current proposal have not been explored and require additional review;

4. PG&E supports treating commission-approved and mandated allocations of renewable energy credits from long-term contracts in the IOUs' portfolios as long-term as to the receiving LSE;
5. The spring partial voluntary allocation and market offer does not have sufficient detail;
6. Increased reporting is not necessary, given the level of detail already provided in the Energy Resource Revenue Account ("ERRA") Compliance Review Application;
7. IOUs canvassing generators could create an excessive administrative burden and the IOUs should retain sole discretion for reassigning contracts; and
8. The shareholder plan developed by Protect Our Communities Foundation's ("POC") proposal should be dismissed.

PG&E looks forward to continuing to engage in this process and working through some of the important implementation details with parties, potentially as another phase of the Working Group process.

I. PG&E SUPPORTS A SIMPLER MECHANISM FOR ALLOCATING OUT THE COSTS AND BENEFITS TO ALL CUSTOMERS; IF NOT, CO-LEADS SHOULD CLARIFY PROPOSAL

The current Voluntary Allocation, Market Offer (VAMO) proposal put forth by the Co-Leads) represents many weeks of intense and impressive collaboration between the Co-Leads and other parties. PG&E appreciates the work that has been put in to develop the VAMO framework particularly given the diverse interests of the stakeholder group. However, at this point PG&E recommends looking for ways to simplify the proposed framework to ensure that it works within the existing regulatory and market. For example, Co-Leads should consider whether it is necessary for both the allocation to be voluntary and for products to be tradable after the fact; each of these attributes adds significant complexity and they seem to achieve the same thing (flexibility for CCAs and DAs). A mandatory allocation of tradable products would likely be far simpler and quicker to implement than the current proposal.

If the co-Leads do not simplify the proposal, PG&E recommends clarifications and changes to the proposal as shown below. Most of these recommendations are for clarity. The addition of the allocation of the GHG-emitting attribute is something that should be addressed to prevent "cherry-picking" of the PCIA portfolio and unexpected results on the Power Content Label ("PCL") (e.g., greenhouse gas emissions that do not show up on any load serving entities PCL). PG&E also recommends that for any firm allocations or sales, Co-Leads clearly spell out mechanisms to prevent risk shift to bundled customers. Finally, the terms for all products are limited to 1-year in the VAMO to allow for continued optimization of the PCIA portfolio; any long-term sales through the auction would prevent the IOU from portfolio optimization activities such as the propose Request for Information ("RFI") process. PG&E's suggested changes to the current proposal from the Co-Leads are in *italics* and red font.

TABLE 1
SUMMARY OF THE VOLUNTARY ALLOCATION AND MARKET OFFER PROPOSAL FOR THE IOUS' RESIDUAL PCIA-ELIGIBLE PORTFOLIO

	Local RA	**System/Flex RA**	**RPS**	**GHG-free**	***GHG-emitting***	***Energy***
Pro rate vintage share	Peak-load	Peak-Load	Forecasted Annual Load Share	Forecasted Annual Load Share	*Needs further develop-ment*	*Actual Load*
Allocation	Mandatory	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (in 10% increments)*	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (in 10% increments)*	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (all or nothing)*		*Mandatory*
Market Offer	N/A	Monthly or Annual	~~Long-term and~~ *Annual*	N/A		*N/A (CAISO Market)*

Unit Contingent or Firm	*Year 1: Firm Years 2 and 3: Unit contingent*	*Spring[1]: Unit continent Fall: Firm*	*Unit continent*	*Unit contingent*		*Unit Contingent*
Risk Mitigation for Firm Product	*Shared penalties*	*Shared penalties*	*N/A*	N/A		*N/A*
Term	*3 years (100% Year N, 100% N+1, 50% N+2)*	*1 year*	*Allocation: vintage or 1 year; Market Offer: 1 year*	*1 year*		*1year*

[1] The Spring auction should only occur if the issues described in these comments are resolved.

Finally, the Co-Leads should clarify in the Final Report that the Working Group 3 VAMO applies to the investor owned utilities' ("IOU") residual PCIA portfolio, i.e., the portfolio that remains after IOUs conduct portfolio optimization activities, which could include sales. Long-term sales or fixed volume allocations in VAMO would restrict the ability of the IOU to divest resources, assign contracts, buy out contracts, sell products through other competitive processes, or otherwise reduce the size of the PCIA portfolio and should not be adopted as part of the proposal. For example, if PG&E sells a long-term RPS product through the VAMO, it cannot then assign or allow a buy-out the underlying contract.

II. FURTHER CLARIFICATION OF THE EXISTING PROPOSAL, INCLUDING REAL-WORLD EXAMPLES, IS NECESSARY TO DETERMINE IF IMPLEMENTATION IS FEASIBLE

PG&E supports an implementation phase for the portfolio optimization and VAMO framework. The Co-Leads have developed a thoughtful framework that helps move forward the goals of PCIA proceeding. However, implementation of the proposal will be complex, with a very high likelihood that details that will need to be further clarified and resolved. This is needed to avoid any unintended consequences and determine when the California Public Utilities Commission ("the Commission") and load serving entities ("LSEs") will be ready to implement the proposal. Specifically, PG&E recommends the implementation phase focus on providing examples in order to further clarify the following topics and answer the following questions:

- Timeline

    - How will the VAMO interface with the existing RA market timeline for both CPUC and California Independent System Operator ("CAISO")?

    - If the RA timing needs to move up, as indicated in Slide 18 to the Fourth Workshop Presentation, what steps would be needed for that to occur and what timing of implementing those changes?

- Administration and additional costs

    - How would the cost of administering the auction be decided and what would the cost recovery and cost allocation look like?

    - Are the IOUs required to run the market offer? What sort of walls would need to be put in place for the IOUs to run the market offer and participate in it? Could the administration be outsourced to a third-party?

    - Would there be three separate auctions for each IOU, or could there be one across all three IOUs? If there are three separate auctions, are there any timing or sequencing issues for state-wide products?

- Specific Examples

    - If required, how would the long-term sales through the VAMO work with the proposed Request for Information process?

    - How will the prepayment (Working Group 2) fit in?

    - What happens if all parties elect to take their allocation for the voluntary products?

    - What happens if no parties elect to take their allocation for the voluntary products?

    - What happens if no parties bid in the auction?

    - How do the long-term allocation and the recently proposed Request for Information[1] process work in concert?

    - Does the IOU maintain sole discretion in its role as scheduling coordinator for the PCIA resources? Will there be cost caps for substitute RA, for example?

[1] See December 11 Co-Lead Presentation at page 25.

- What happens if there is no substitute RA available for a forced outage or a cancelled planned outage? How is the CAISO/Federal Energy Regulatory Commission compliance risk shared?

- Would the RA VAMO process change with the implementation of a Central Buyer? Would there be a process to revisit whether the complexity of the VAMO continues to be necessary with a Central Buyer in place?

- If Ratemaking Option 2 is adopted, what measures can be put in place to ensure that the IOU is paid? If the IOU is not paid in a timely manner, will the costs be socialized?

- What happens to the VAMO process if an LSE suddenly stops serving customers?

III. THE RATEMAKING CHALLENGES ASSOCIATED WITH THE CURRENT PROPOSAL HAVE NOT BEEN EXPLORED AND REQUIRE ADDITIONAL REVIEW

The Co-Leads have proposed two ratemaking options for the VAMO proposal. Under Ratemaking Option 1, when an LSE takes the allocation, the attribute values for RPS and RA in the indifference calculation are zero, which differs from the current construct where the RPS and RA attributes are assigned a value based on the Commission-approved Market Price Benchmark (MPB). PG&E prefers Ratemaking Option 1 because it minimizes the ratemaking and administrative complexity, which is not insignificant, and arrives at a fair allocation of the costs and benefits of the portfolio.

The modified Ratemaking Option 2 presented at the December 11, 2019 Workshop continues to rely on a market price benchmark (MPB) for energy, renewable portfolio standard (RPS) attributes, and resource adequacy (RA) attributes, and yet expands the administrative complexity. The Co-Leads propose to expand the data used to calculate RPS value beyond the n-2 framework approved in Decision (D.) 19-10-001. Specifically, the Co-Leads recommend that the allocation price should factor in the weighted average price of "historical" long-term transactions that occurred in periods prior to those considered in the currently approved MPB, which considers transactional data for periods up to n-2 where "n" is defined as the forecast year.

The historical period under consideration in the Co-Lead presentation suggests that the periods would be tied to any long-term contracts sold under the VAMO that are still delivering RPS for the prompt year.[2] It is not clear whether or how the proposal would incorporate the requirement from D. 19-10-001 to examine long-term bundled RPS value.

It appears that the problem the modified proposal is trying to address is the ability to have the RPS attribute value reflect a long-term sales prices made through the VAMO to ensure those LSEs that decide to commit to a long-term allocation pay a weighted average attribute value that reflects long-term sales activity on a weighted average basis. That is, the proposal would not only include the current n-2 transaction market values but would also include any sales activity coming out of the VAMO process. PG&E opposes the requirement to sell long-term products through the VAMO as this requirement prohibits the ability to perform portfolio optimization activities, as explained above.

In addition to opposition to the underlying assumption that the VAMO should include long-term sales, PG&E has reservations on the administrative complexities associated with implementing such a methodology and whether the proposal will have unintended consequences which might result in an MPB for the RPS attribute that is not current or skews the market value far afield from the current market value, which was a flaw in the previous MPB approved in D.11-12-018 for RPS attributes. The previous methodology's attribute price was based primarily (68 percent weighting) on newly delivering contracts that were signed 3 to 6 years prior to the current year's PCIA forecast. The criticism for this methodology was that the stale attribute pricing was not reflective of the current market value, which caused cost shifts between bundled customers and departing customers.

[2] See December 11 Co-Lead Presentation at page 21.

Another concern would be situations where there are no LSEs taking long-term allocations, yet the methodology is dogmatically implemented to include the VAMO long-term contract pricing to solve the price parity issue for LSE's taking allocations, yet there are no LSEs long-term allocations to worry about.

Lastly, it is not well defined in the presentation whether the modified Option 2 would apply only to the RPS attributes, which the VAMO would be selling long-term, but it is unclear whether the proposal would also apply to any long-term RA sales. PG&E would request that the Co-Leads clarify if the modified Ratemaking Option 2 proposal could potentially apply to any long-term RA products.

PG&E notes that none of these issues regarding benchmark values exist with Option 1 because Option 1 does not use benchmarks. PG&E continues to recommend Option 1.

IV. PG&E SUPPORTS TREATING COMMISSION-APPROVED AND MANDATED ALLOCATIONS OF RENEWABLE ENERGY CREDITS FROM LONG-TERM CONTRACTS IN THE IOUS' PORTFOLIOS AS LONG-TERM AS TO THE RECEIVING LSE.

The Co- Chairs propose that "in order for an LSE to receive the 'long-term' benefits from RPS allocation, they must elect to receive their allocation share through the life of their vintage."[3] The Co- Chairs note that under their proposal, short-term allocations would not count as long-term for the LSE receiving the allocation.

The RPS statute, as revised in 2015 by Senate Bill 350, includes a "long-term" procurement requirement in Section 399.13(b). That provision requires that, beginning January 1, 2021, at least 65 percent of a retail seller's procurement be from "its contracts of 10 years or more in duration or in its ownership or ownership agreements" for RPS-eligible

[3] Workshop presentation, Slide 12.

resources. While the Commission has implemented this requirement in Decision 17-06-026, it did not expressly decide there whether and how Renewable Energy Credits (RECs) that are allocated through a Commission-mandated cost allocation process like the PCIA should be treated for purposes of the long-term procurement requirement of the LSE receiving the allocation.[4] This is not surprising given that the allocation of RECs had not yet been authorized for the PCIA or any other Commission-mandated cost allocation mechanism as of the time of that Decision; rather, the value of RECs has been determined through either an administratively-set price or through the sale of the RECs by the IOU, and then the ascribed value has been credited toward the net cost of the contract that is allocated to the LSEs.

The Working Group 3 proposal requires the Commission to directly address this issue and to further interpret the statutory long-term procurement requirement in the context of allocated renewable energy credits ("RECs"). PG&E submits that any such further interpretation be narrowly confined to the situation at hand: the mandatory, Commission-authorized allocation of RECs from long-term contracts in the IOUs' portfolios through a Commission-approved allocation mechanism. In other words, the final Working Group 3 proposal should specifically address the non-precedent-setting nature of this treatment and should ask the Commission to limit the ability of RECs allocated from contracts with less than 10 years remaining to count as long-term <u>only</u> in the context of Commission-mandated cost allocation. Any other transfers or sales of RECs, including those RECs sold through any Market Offer aspect of the Working Group 3 proposal (if this aspect of the proposal is preserved), should continue to be subject to the ordinary long-term rules requiring contractual commitments of at least 10 years.

[4] *See* D.17-06-026, pp. 15-25 (discussing definition and characterization of "long term" procurement and ownership commitments for purposes of implementing Section 399.13(b), but not addressing Commission-mandated REC allocations as part of the PCIA).

There is a logical basis for distinguishing mandatory PCIA REC allocations from other types of voluntary REC sales. The long-term contracts in each PCIA vintage represent contractual commitments entered into for at least 10 years by an IOU on behalf of all of its bundled customers at the time of execution. That includes customers that subsequently departed from IOU bundled service and chose to take service from other LSEs. By so departing, those customers then became subject to the PCIA because they remain responsible for the portion of the IOU's procurement undertaken by the IOU prior to the customer's decision to depart. The Working Group 3 Proposal now suggests allocating the same RECs that were procured originally on behalf of departed load to those same departed load customers. This is reasonable because those customers are paying through the PCIA for the long-term RPS contracts that were procured on their behalf.

Given this perspective, PG&E sees no statutory barrier to the Working Group 3 proposal for RPS Long-Term Attribute Preservation, so long as the Commission makes clear that this interpretation only applies in the context of Commission-mandated cost allocation. This is true even if some or all of the RPS contracts in a particular vintage have less than 10 years remaining in deliveries. The original contract, when entered into by the IOU on behalf of the departed load customer, was long-term, and it supported the planning and financing stability goals underlying the long-term requirement, as further described in D.17-06-026. Allocation of the RECs associated with that long-term contract should remain long-term as to the receiving LSE. Any further sale of the same RECs by the receiving LSE would be subject to the usual long-term duration requirements to determine if the buyer of those RECs could count it as long-term.

V. THE SPRING PARTIAL VOLUNTARY ALLOCATION AND MARKET OFFER DOES NOT HAVE SUFFICIENT DETAIL

The Co-Leads presented a very high-level explanation as to how the Spring VAMO would occur.[5] PG&E requests additional details on how the spring VAMO would work in relationship to ongoing sales as a part of the IOUs portfolio optimization along with the CAISO and Commission require adjustments that transpire between Q1 and mid-September. Further details on how the allocations would be determined in Q1 needs to be discussed, as without a prescriptive method the values would be subject to dispute and potential litigation leading to unnecessary costs to customers.

The Co-Leads correctly point out that "there is only a short window for procurement between receiving RA obligations and the year-ahead RA showing" and the intent of the spring VAMO is good, i.e. to help relieve the pressure on the fall VAMO and RA market. Examples would greatly assist in understanding how the spring market offer could occur. For instance, when an LSE accepts the allocation, but it then opts-out of its allocation in the fall, how and when would the requirements adjust? And how would that impact the timing of the fall VAMO and the ongoing RA market? Or, if there are significant methodological changes to calculating net qualifying capacity ("NQC") or effective load-carrying capability ("ELCC"), then how would the allocations be adjusted? Should all the allocations in the spring be unit contingent to address issues with hydro counting rules? As discussed above, examples are needed to help clarify some of these thorny issues and the Co-Leads and Commission should consider an implementation phase following the Working Group 3 final decision.

VI. INCREASED REPORTING IS NOT NECESSARY, GIVEN THE LEVEL OF DETAIL ALREADY PROVIDED IN THE ERRA COMPLIANCE REVIEW APPLICATION

Limited detail was provided on the specific changes that are desired as part of compliance filings in the ERRA proceedings.[6] This section provides several considerations that the Co-Leads may want to incorporate into their proposal.

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[5] Workshop presentation, Slide 18.
[6] See Workshop Presentation, Slide 28.

The ERRA Compliance Review Application provides detail on the defaults that lead to terminations of contracts. It is not clear what types of defaults require reporting under the proposal, but additional reporting on all defaults, including those that do not result in terminations, may not provide meaningful insights and could create an undue burden on the IOUs. Defaults in contracts happen, but so does the curing of those defaults by counterparties. Furthermore, limited detail was provided for the recommendation to "report cost savings form active portfolio management." Again, more detail is needed to determine what is being requested, but PG&E's initial thinking is that the current ex ante assessment in the ERRA Compliance Review Application is adequate to evaluate cost savings from utility portfolio management activities.

VII. CANVASSING GENERATORS COULD CREATE AN EXCESSIVE ADMINISTRATIVE BURDEN AND THE IOUS SHOULD RETAIN SOLE DISCRETION FOR REASSIGNING CONTRACTS

As part of Workshop #4, the Co-Leads put forward a proposal under which an IOU would be obligated to regularly solicit interest from its contractual counterparties regarding assignments or buy-outs of those contracts. The purpose of this RFI would be to put any such interested counterparties into contact with other non-IOU LSEs that may be interested in taking assignment of the contract or entering into a new contract with the generator.

PG&E opposes the RFI proposal because it forces the IOUs into a position of serving as a market platform provider in a manner that is (i) uncompensated; (ii) creates administrative costs and (iii) not needed for bundled customers. Should the Commission adopt an RFI framework, there is a need to limit the number of participants that engage in the RFI at any given period. Due to limited resources of the IOUs, an 'open season' or some other framework that helps limit the number of parties that are participating in the RFI at any given period would be needed.

The sole discretion to enter into any contract reassignments or novations should remain with the IOUs, subject to the Commission's oversight of the reasonableness of an IOU's contract administration. The purpose of PCIA is to fairly share the benefits and costs of the IOU portfolios that have been acquired for customers across all LSEs. An integral criterion to focus on is the optimization of the IOU portfolios. The aim is not for the IOUs to optimize portfolios for all the LSEs. Thus, when the IOUs determine, based on their sole discretion, that there is a desire to maintain any contract within its portfolio, that determination should be assessed against existing prudent manager criteria and not on new criteria (i.e., from the proposed RFI process).

If the RFI is adopted, the Co- Leads should clarify what the timing of the RFI would be and how it would work in terms of the VAMO and existing portfolio optimization practices. would help, along with examples of different scenarios that may transpire (e.g. a contract that is under sales negotiations that are then included in the RFI).

VIII. THE SHAREHOLDER PLAN DEVELOPED BY PROTECT OUR COMMUNITIES FOUNDATION SHOULD BE DISMISSED

The POC proposal for shareholder penalties raises significant concerns. First, it appears that under this proposal penalties could be imposed irrespective of actions outside the sole control of the IOUs. This might include, for example, changes to the NQC or ELCC list or other changes to compliance rules or processes adopted by the CAISO, the California Energy Commission, or the Commission that impact the process or timing of the VAMO. Adopting an "automatic" penalty as proposed by POC would hold IOUs to an unreasonable standard in light of these potential regulatory changes. Second, instituting automatic penalties runs a high risk of violating an IOU's right to due process, if those penalties are applied without any opportunity of the IOU to provide mitigating evidence or explanations. Third, POCs argument to eliminate the PCIA cost recovery eligibility in five years ignores the fact the Commission rejected similar arguments in Phase 1 of this rulemaking proceeding. In D.18-10-019, the Commission rejected the CCA parties' arguments to sunset departing load customers' PCIA obligation, and determined that "a [sunset] provision should not be adopted in this decision".[7] In arguing that the IOUs should eliminate any excess procurement in their portfolios on a set, near-term timeframe, POC's Portfolio Optimization proposal fails to consider the contractual commitments

[7] *See* D.18-10-019, p. 82 (Finding of Fact 18); *see also id.*, pp. 60-61 (noting that "customer indifference requires the equitable distribution of all stranded costs among customers for whom those costs were incurred").

that the IOUs have entered into on behalf of all then-bundled customers that extend beyond a 5-year. POC's proposal is unworkable in light of these commitments and fails to recognize the ongoing activities undertaken by the IOUs consistent with Standard of Conduct 4 of their respective Bundled Procurement Plans. It is for these reasons that PG&E believes that POC's proposal should be rejected.

IX. CONCLUSION

PG&E respectfully requests that these informal comments inform the Commission's consideration of the allocation and market offer mechanism proposal. PG&E looks forward to collaborating with the Co-Leads and all other participants in the PCIA discussions.

Respectfully Submitted,

By: /s/ M. Grady Mathai-Jackson
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: December 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

PROTECT OUR COMMUNITIES FOUNDATION'S COMMENTS ON AND PROPOSALS FOR PORTFOLIO OPTIMIZATION

Tyson Siegele
Energy Analyst
Protect Our Communities Foundation
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

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I. Introduction

On December 11, 2019, the co-chairs of Working Group 3 convened a workshop at which they requested that parties submit comments on their portfolio optimization proposals via informal comments to the service list by December 20, 2019. Protect Our Communities Foundation (POC) submits these comments pursuant the schedule set by the co-chairs. These comments first address the co-chairs' portfolio optimization mechanism, then POC's automatic enforcement mechanism, and finally refinements to the co-chairs' voluntary allocation and market offer proposal.

Portfolio optimization mechanisms should promote the sale of Power Charge Indifference Adjustment-eligible resources in a manner that ensures the greatest value for customers. As a first priority, investor-owned utilities (IOUs) should sell entire resources, which would create the most value for customers who would otherwise pay the full cost of those resources through the Power Charge Indifference Adjustment (PCIA). Secondarily, portfolio optimization mechanisms should also capture the full value of all resources' attributes on a short-term basis through the voluntary allocation and market offer mechanism. Accordingly, IOUs should continue to perform long-term portfolio optimizations that include the sale of entire resources and buyout of power purchase contracts outside of the co-chairs' proposals.[1]

II. POC supports the co-chairs' proposal that IOUs issue a request for information for contract assignment and buy-outs.

The co-chairs propose a process where IOUs are required to issue a request for information (RFI) for contract assignment and buy-outs.[2] This process would connect interested sellers with other market participants interested in receiving an assignment of a resource contract. It would also provide an opportunity for sellers to propose contract buy-outs. POC supports this proposal as one of many potential vehicles for IOUs to assign or buy-out entire resources. POC agrees that these assignments and buy-outs, which would remove a contract from an IOU's portfolio in perpetuity, should take priority over any allocations or auctions made pursuant to the annual voluntary allocation and market offer mechanism.

A. Contract buy-out costs are subject to the PCIA cap.

The cost of any contract buy-out made pursuant to this proposal would be subject to the PCIA cap. Southern California Edison's (SCE's) contention at the workshop that the PCIA cap does not apply to contract buy-outs is wrong. In its phase 1 decision, the Commission established a cap on annual increases to the PCIA rate to "reduce extreme PCIA price spikes, and bill impacts" and "protect[] against volatility in the PCIA."[3] Nothing in D.18-10-019 allows or suggests that any costs properly included in the PCIA are exempt from the cap. Moreover, nothing in the Commission's discussion of the cap's accounting suggests that utilities should set

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[1] R.17-06-026, PCIA Phase 2 –Working Group Three Portfolio, Optimization and Cost Reduction, and Allocation and Auction, Refinement of Issue 1 Proposals; Issues 2-4, Workshop No. 4, Presentation at 9 (December 11, 2019) (December 11, 2019 Presentation).

[2] December 11, 2019 Presentation at 25-26.

[3] R.17-06-026, D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at 85-86 (October 19, 2018).

up accounting mechanisms to track PCIA costs outside of the cap because the Commission did not authorize any PCIA costs to be outside of the cap.

Further, IOUs are not harmed by the cap because the Commission ordered ratepayers to pay for the full cost of any PCIA rate above the cap—including interest—over time.[4] The IOUs' investors will be compensated at the Commission-approved rate of return for any debt issued to cover short-term buy-out costs that are unrecovered. The IOUs should welcome the opportunity to earn a return on debt issued due to the PCIA cap rather than arguing against rate stability for unbundled customers.

B. Only contracts priced below the market price benchmark should be excluded from the request for information.

POC supports requiring low-priced contracts to be retained by IOUs for the benefit of customers. To meet this goal, the co-chairs are considering excluding contracts priced below 115% of the market price benchmark (MPB) from the RFI mechanism.[5] POC recommends that the co-chairs set this percentage at 100% instead of 115%. The co-chairs have not articulated a rationale for setting the cut-off at 115% and POC is concerned that this may foreclose the possibility of an IOU divesting itself from a contract that is above the market price. This threshold will be used to determine which contracts are included in the RFI, not which contracts are ultimately selected by the IOU for assignment or buyout. At the end of the negotiation process, "IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards," and any "accepted offers will be subject

[4] *Id*. at 85-87.

[5] December 11, 2019 Presentation at 26.

to approval by the CPUC."[6] Therefore, any contract above market price should be included for consideration for removal from an IOU's portfolio in the RFI.

Fluctuation in the MPB is not a reason to remove any contract that is above market cost from consideration in the RFI. POC acknowledges that the wholesale market prices vary and are currently correlated with natural gas prices.[7] However, as renewable energy and energy storage become a larger part of the overall market, the price of renewables and storage will increasingly affect and soon dictate wholesale market prices. And the price of those resources are steadily declining. Between 2007 and 2018, the cost of RPS contracts decreased from approximately $180/kWh to $40/kWh.[8] That trend is continuing. Los Angeles Department of Water and Power (LADWP) signed a contract in 2019 for solar at $19.97/MWh, or $33/MWh when including storage.[9] LADWP's electricity price for solar plus storage falls significantly below the approximately $50/MWh average wholesale electricity price in 2018.[10]

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[6] December 11, 2019 Presentation at 25.

[7] Between 2010 and 2018, the total annual wholesale cost of electricity varied between $50/MWh and $30/MWh. Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance at 3 (May 2019) (Figure E.1), http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf; Department of Market Monitoring, 2014 Annual Report on Market Issues and Performance, at 4 (June 2015) (Figure E.1), http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf

[8] Cal. Public Utilities Commission, 2019 Padilla Report at 7 (May 2019) (Figure 3), https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2019/Padilla%20Report%202019%20-%20Final(1).pdf

[9] Request for Official Notice, Exhibit C, Excerpts of Attachment to Report from City Administrative Officer (Sept. 11, 2019), http://clkrep.lacity.org/onlinedocs/2019/19-1081_misc_4_09-20-2019.pdf.

[10] Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance at 3 (Figure E.1).

With renewable and storage resources comprising an increasing share of the state's resources, they will exert a downward pressure on the wholesale market price and MPB. Accordingly, the MPB will not simply fluctuate up and down in the future. As wholesale market prices are decoupled from gas prices, they will mirror the downward trajectory of the renewables and storage market. Therefore, it is inappropriate to exclude any contracts above 100% of the MPB from the RFI process.

III. IOUs should terminate all contracts above the market price benchmark whenever legally possible.

In the event of a material default by a counterparty to a contract above the MPB, the Commission should require IOUs to terminate that contract. The co-chairs propose to require that all IOUs' Energy Resource Recovery Account (ERRA) compliance filings include reports of any material events of default, termination rights, and resulting actions.[11] POC supports this reporting requirement because it increases transparency of the IOUs' activities to divest their portfolios of high-priced contracts. Yet simply requiring reporting does not go far enough.

In addition to the reporting requirement, the Commission should require IOUs to terminate high-priced contracts in the PCIA portfolio in the event of material default or the ability to exercise a termination right. The only exception to this rule should be if an IOU is able to reach an agreement with the counterparty that would reduce the PCIA by a greater amount than would be achieved through termination.

[11] December 11, 2019 Presentation at 28.

IV. The voluntary allocation and market offer proposal should include POC's automatic enforcement and shareholder responsibility mechanisms.

The co-chairs' allocation and auction proposal should include automatic enforcement mechanisms to ensure IOUs immediately implement the portfolio optimization mechanisms adopted by the Commission.

The co-chairs' voluntary allocation mechanism requires IOUs to regularly provide to other load serving entities (LSEs) the quantity of their forecast and actual allocation of resource attributes. IOUs that do not provide these forecasts and actual allocation amounts on a schedule approved by the Commission should provide bill credits to bundled and unbundled customers. These bill credits should be given by IOU shareholders to customers within 60 days of the missed deadline, without the need for any Commission action.

IOUs should administer the voluntary allocation mechanism in a timely, efficient, fair, and transparent manner because they control access to information about the PCIA resources paid for by all customers. POC's automatic enforcement and shareholder responsibility mechanism aligns the interest of shareholders in avoiding penalties with the interests of all customers in an efficient and timely administration of the allocation mechanism. It also compensates customers when they are harmed by an IOU's mismanagement of the allocation mechanism. These bill credits are modeled on the customer service guarantees that shareholders provide customers when an IOU misses a deadline that has important ramifications for the customer, including missed appointment times and inaccurate bills.[12] Bill credits are appropriate

[12] Dkt. A.02-05-004, Southern California Edison 2003 General Rate Case, D. 04-07-022, Opinion on Base Rate Revenue Requirement and Other Phase 1 Issues, at 164 (July 8, 2004) (approving $30 bill credits with the justification that "a self-enforcing mechanism that can create a significant incentive for SCE to meet the adopted standards"); *id*. at 126 (shareholders responsible for bill credits); Pacific Gas & Electric Co., Service Guarantees, https://www.pge.com/en_US/residential/customer-service/other-services/service-guarantees.page

in this case because an IOU that fails to provide a forecast or actual allocation on schedule impedes the LSEs' ability to efficiently manage their portfolios; this has important ramifications for customers.

For example, IOUs that publish renewable portfolio standard (RPS) or greenhouse gas-free (GHG-free) allocations that underallocate attributes to unbundled customers should provide a $30 credit to unbundled customers' bills. Similarly, IOUs that publish RPS or GHG-free allocations that underallocate resources to bundled load customers should provide a $30 credit to bundled customers' bills.[13] Based on information provided by the co-chairs to POC, it does not appear that IOUs will publish allocations of resource adequacy (RA) attributes, therefore this proposal does not discuss RA allocations.

Next, the co-chairs' market offer mechanism requires IOUs to regularly administer auctions for certain attributes from PCIA resources. The efficient administration of these solicitations is an essential part of the co-chairs' proposal to reduce the PCIA rate. Due to the IOUs' track record in administering PCIA resources, POC is concerned that IOUs may not efficiently and accurately administer these auctions.[14] POC's proposal aligns shareholders'

(accessed Dec. 19, 2019) ($30 bill credits approved in 1999 and 2003 General Rate Case; shareholders responsible for bill credits).

[13] At the December 11, 2019 workshop, IOUs expressed concern about the inability to contest the automatic bill credits included in POC's proposal. POC does not oppose Commission review of the bill credits after they are issued.

[14] For example, Peninsula Clean Energy sought to purchase local RA for the 2019 reliability year. It responded to all of PG&E's requests for offers and made other efforts to procure capacity, but was unable to procure enough local RA to meet its need. Notice of Ex Parte Meeting of the California Community Choice Assn., at 2 (May 13, 2019). The needed capacity was subsequently offered by PG&E to the market only after the compliance deadline for LSEs to obtain RA for 2019. *Id*. This is one example of IOUs unreasonably administering their resource portfolios.

interest in avoiding penalties with customers' interest in efficient administration of these auctions.

POC proposes that if an IOU that does not complete its auction on the schedule set by the Commission, within 60 days of the missed deadline the IOU's shareholders should provide a $30 bill credit to the unbundled customers on whose behalf the action was to be conducted.

Further, POC proposes that an IOU withholding resources that an LSE requested be auctioned provide bill credits to the unbundled customers on whose behalf the auction was to be conducted. The total shareholder cost would be the highest auction bid multiped by the quantity of attributes not auctioned. If no auction took place, the total shareholder cost would be the most recent MPB for that attribute multiped by the quantity of attributes not auctioned. This amount would be distributed to unbundled customers on whose behalf the auction was to be conducted through bill credits.

POC is concerned about the ability of the working group to develop an effective shareholder responsibility proposal in the time available before the working group's final report is due on January 30, 2020. POC has presented the only shareholder responsibility proposal to the working group to date. If the co-chairs are not able to develop a proposal that results in an effective shareholder responsibility mechanism, they should submit their completed proposals for Commission consideration and request additional time for the working group to develop an effective proposal to address this critical issue.

V. POC supports the adoption of a voluntary allocation and market offer framework that includes several changes from the co-chairs' proposal, including market offers for local RA and GHG-free attributes.

A. A spring market offer will maximize the value of RA attributes for customers.

POC supports the co-chairs' proposal to hold a second RA market offer and auction in the spring of each year.[15] Under this proposal, LSEs have an opportunity to decline their allocation for the following year in the first quarter. A portion of any declined allocations are then made available in the spring market offer and auction. POC supports this proposal because it provides an opportunity to maximize the value of RA attributes for LSEs that know in advance that they plan to decline their allocations. Further, POC appreciates that this proposal allows LSEs maximum flexibility because they are not required to decline allocations in the first quarter and retain the right to decline their full allocation in the fall.

B. A cap on long-term RPS sales is unnecessary, but if implemented should be accompanied by regular reports on its impact.

At the December 11, 2019 workshop, the co-chairs proposed that the Energy Division publish an annual report "summarizing results of the auctions and potential impact of the cap on long-term sales on realized value."[16] While POC would prefer that the auction not contain a cap, if one is implemented POC supports this reporting requirement.

POC disagrees with the co-chairs' proposal to cap the quantity of long-term sales made in the RPS auction. To capture the most value for the RPS product, IOUs should always accept the highest price offered for the sale of RPS regardless of contract length. A large quantity of renewable resources will enter the market as California moves towards its statewide renewable

[15] December 11, 2019 Presentation at 13.

[16] December 11, 2019 Presentation at 13.

energy goals and more Community Choice Aggregators ("CCAs") with aggressive renewable energy mandates form. With this influx of new renewable resources—built with the advantage of today's prices that are lower than the cost of the older RPS resources[17] in the PCIA portfolio—the market price of RPS products is likely to drop precipitously in the next several years. Therefore, the PCIA auction mechanism should capture the highest value of RPS products available in the near term. POC believes that the ability to secure long-term revenues for RPS resources in the near term is more important than ensuring that allocations from the PCIA portfolio are available to customers who switch between LSE providers.

C. POC continues to support the co-chairs' local RA allocation proposal when paired with an auction.

The co-chairs offer a proposal that allocates local RA to LSEs. POC supports the premise of this proposal as a short-term portfolio optimization mechanism if it is paired with an auction. Below, POC discusses its proposed change to the local RA proposal's treatment of penalties.

First, POC disagrees with the co-chairs' proposal that

> any CAISO costs or penalties required for, or imposed as a result of, local RA resource outages will receive full cost-recovery through the PCIA . . . except for any costs disallowed through the IOU's ERRA proceeding.[18]

Penalties should not automatically be eligible for recovery in the PCIA. IOUs maintain a responsibility to prudently manage their PCIA-eligible resources to avoid any penalties. Therefore, it is unreasonable to presume that these penalties are customers' responsibility.

[17] CA Public Utilities Commission, 2019 Padilla Report, at 7 (May 1, 2019) (figure 3), https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2019/Padilla%20Report%202019%20-%20Final(1).pdf.

[18] R.17-06-026, Detailed RA Sales Process Strawman, Local RA Allocation, GHG-Free Allocation & Voluntary Allocation Process: Workshop No. 2 Presentation, at 25 (July 25, 2019) ("July 25, 2019 Presentation").

Instead, shareholders should take financial responsibility for any penalties, as they are responsible for managing their PCIA-eligible resources in a way that avoids the imposition of penalties.[19] Should shareholders seek to impose the cost of penalties on departing load customers, an IOU should be required to file an application, in a docket distinct from the ERRA proceeding, showing why these costs should be customers' responsibility. Put simply, penalties that result from imprudent management of resources should be shareholders' responsibility.

D. POC continues to support the co-chairs' GHG-free allocation proposal when paired with an auction.

The co-chairs offer a proposal that allocates a proportional share of GHG-free attributes to other LSEs.[20] This proposal makes sense because GHG-free attributes have a value, and all customers who pay the PCIA are entitled to a portion of that value.[21] POC supports this proposal as a short-term portfolio optimization solution if it is paired with an auction. POC also suggests two clarifications to improve the co-chairs' GHG-free proposal.

GHG-free resources include nuclear and hydroelectric resources. Some CCAs are not authorized to purchase or use nuclear resources, therefore any GHG-free allocation proposal should include a mechanism allowing LSEs to opt out of receiving GHG-free attributes from nuclear resources. The co-chairs disagree on what to do with the declined GHG-free attributes from nuclear resources. Commercial Energy would auction the declined attributes and credit the auction proceeds to the LSEs declining the attributes.[22] California Community Choice

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[19] If IOUs cannot manage their resources without incurring penalties, or do not want the obligation of resource management, they should sell those resources.

[20] July 25, 2019 Presentation at 26-30.

[21] *See* July 25, 2019 Presentation at 27 (a "credit within [the] Power Content Label, Clean Net Short, or other similar reporting mechanisms").

[22] *See* July 25, 2019 Presentation at 28; *Id*. at 33.

Association (CalCCA) and SCE would similarly allow LSEs to decline receiving GHG-free attributes from nuclear resources, but instead of auctioning off the declined attributes, they "would be reallocated automatically amongst LSEs participating in the allocation."[23]

POC continues to support Commercial Energy's proposal because it provides the LSE declining an allocation of GHG-free attributes the financial value of the attributes to which it was entitled. In contrast, CalCCA and SCE would allocate the value of attributes paid for by one LSE to the customers of another LSE without compensation. CalCCA and SCE offer no support for their proposal to shift the value of attributes from one LSE to another without compensation. This aspect of the proposal offered by CalCCA and SCE should be rejected because it violates the requirements of Public Utilities Code sections 365.2 and 366.3 to prevent cost shifting.

VI. Conclusion

POC thanks the co-chairs for the opportunity to submit these comments.

[23] July 25, 2019 Presentation at 28

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SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai
ELLISON FOLK
YOCHANAN ZAKAI*
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: December 20, 2019

PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele
TYSON SIEGELE
Energy Analyst
Protect Our Communities Foundation
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

1192351.7

* Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

January 6, 2020

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PCIA WORKING GROUP 3 FOURTH WORKSHOP (R.17-06-026)

SDG&E appreciates this opportunity to provide comments regarding the fourth workshop held by Working Group 3 ("WG 3") in Phase 2 of the Power Charge Indifference Adjustment ("PCIA") proceeding. In Decision (D.) 18-10-019, the Commission established WG 3 to consider the structure, processes, and rules governing portfolio optimization to be adopted by the Commission in order to address excess resources in utility portfolios.

SDG&E supports the recommendation offered by Pacific Gas and Electric Company ("PG&E") to include examples and timelines in the workgroup report. SDG&E also recommends that the WG 3 co-leads schedule an additional workshop to review the open issues that remain in WG 3.

SDG&E's notes that optimization and cost reduction of investor owned utilities' ("IOU") respective resource portfolios must consider both short- and long-term timeframes. It is therefore crucial to ensure that the portfolio optimization measures applied in one timeframe do not interfere with optimization efforts undertaken within another timeframe. During the fourth WG 3 workshop, the co-leads suggested that short term allocations, including allocations of long-term Renewable Portfolio Standard ("RPS") resources, is a contingent product. In other words, even though a load-serving entity ("LSE") elects to accept its share of the allocation, the IOU may optimize its portfolio in the future and LSEs should not be dependent on such future allocations. SDG&E supports this proposal because it provides options for the IOUs to optimize their portfolios without being restricted due to the allocation process.

SDG&E is concerned, however, that the proposed allocation process does not fully address the scope of WG 3, creates inefficiency and could create additional burden for bundled service customers after the IOU has optimized (*i.e.*, "right-sized") its long-term portfolio. First, the allocation process does not reduce the total above-market costs of the utilities' PCIA-eligible portfolios because it shares the total costs with the relevant vintage customers. Second, if an IOU has optimized its portfolio but is then required to allocate portfolio resources to LSE(s), it would be faced with the prospect of going back to the market to re-procure certain products needed to meet compliance obligations. There are only three "markets" that offer such products:

the IOUs must procure products from the primary bilateral market, trade with other LSEs in the secondary market in the case of System and Flexible RA capacity, or participate in its own voluntary allocation market offer ("VAMO") process when another LSE elects to not take its allocation. Finally, if the allocation process results in the IOUs still having surplus capacity, it is unclear whether the IOUs would be required to make such surplus available through the market offer process by electing to not take its surplus capacity. It is not clear whether the VAMO process is superior to the excess sales framework developed during the Working Group 1 process. It would be helpful to parties for the WG 3 co-leads to provide clear examples of how the VAMO process works, compared to the excess sales framework. Given that there will be advantages and disadvantages to both frameworks, SDG&E recommends that each IOU be allowed to utilize either the excess sales framework <u>or</u> the proposed allocation framework, depending upon which best fits its portfolio and best serves the LSEs that also serve customers in the IOU's service territory.

The most recent proposal changes the definition of the market price benchmark ("MPB"). In the Working Group 1 decision (D.19-10-001), the MPB for the various products was limited to certain transactions executed up to 3 years prior to the compliance or delivery year. The most recent proposal would eliminate this limitation and the MPB would be calculated based on all contracts executed for a particular delivery term. The co-chairs' rationale for this proposed modification is that "[l]ong-term sales can create the potential for cost shifts with Rate Making Option 2, when using the Market Price Benchmark approach, as adopted in Track 1, to set price that parties taking allocations should pay."[1] SDG&E disagrees with this conclusion for the reasons set forth below.

First, the allocation framework is not interchangeable with the excess sales framework developed in Working Group 1. This is because the excess sales approach differentiates the various products into three categories: compliance, sold and unsold. The MPB is then used to determine the amount of above-market cost paid by all customers in the vintage and the costs up to the MPB paid by bundled service customers for the compliance portfolio. The MPB does not play a role in the cost allocation for sold and unsold products paid by all customers in the vintage as the sales price sets a specific MPB for each specific sold product while unsold products are valued at zero dollars. Under the allocation framework, these three categories are restructured into a single category as all LSEs in a vintage share in all the attributes and total net costs[2] within that vintage. Thus, the MPB would effectively serve little purpose other than determining the amount of cost paid directly by customers while the remaining "above-market" amount is paid to the IOU by the LSE. The LSE would then have the option to determine how it would recover such costs from its customers. Additionally, it is unclear if the proposal would result in different PCIA rates for different LSEs depending on who takes or does not take allocations because the proposed MPB may be different than the price of a sale in the market offer. In such an instance, who is responsible to make up the difference? Is it the customer or the LSE? SDG&E

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1 WG 3, Workshop #4 Presentation, Slide 21.

2 LSEs share in the total costs net of California Independent System Operator ("CAISO") market revenues.

recommends that the co-leads provide an example in the workshop report to allow parties to better understand the proposal.

Second, it is suggested that including long-term sales in the MPB would offer other LSEs taking the allocations the benefit of having locked in such "long-term" pricing. This makes little sense because as explained above, regardless of the MPB value, an LSE taking an allocation will be taking on its share of the total contract cost (at-market and above-market). A market transaction of a different resource would only impact the amount of cost customers are directly billed by the IOU and the residual amount directly paid to the IOU by the LSE taking the allocation.

Finally, transactions entered into prior to year N-2 may not be reflective of the actual market. It is unclear how the co-leads' proposal to calculate the MPB using weighted average of long-term contracts transacted prior to year N-2 would be implemented. SDG&E recommends that the co-leads include formulas and examples to allow parties to better understand the proposal.

During the fourth workshop, the co-leads discussed various IOU portfolio management and optimization activities. The co-leads proposed a request for information ("RFI") process for contract assignments and buy-outs. The RFI process would connect sellers with LSEs or other market participants with generators under contract with the IOU at that time. The proposed RFI process would also allow generators to propose contract buy-outs. Finally, the process would be held annually for the first two years, after which the Commission would consider whether the process should be modified or continued biannually.

SDG&E is encouraged that the co-leads have proposed a process to facilitate portfolio optimization of the IOUs' portfolios. The IOUs should be actively seeking opportunities to right-size their portfolios and reduce costs for customers. SDG&E believes that a voluntary RFI process could be a start to meeting that goal. SDG&E provides the following comments regarding the co-leads' proposal:

The RFI process should not be the only means for the IOUs to optimize their portfolios and should not be mandatory. The market fluctuates daily, and the right opportunities do not wait for an RFI process to begin – flexibility is crucial to ensuring that ratepayers receive the greatest value from portfolio optimization activities. If the IOUs are permitted to initiate portfolio optimization only during an RFI timeline, any opportunities that fall outside of this timeframe may be lost, which directly undermines the IOU's ability to optimize its portfolio. SDG&E recommends that the IOUs be permitted to optimize their portfolios anytime throughout the calendar year in lieu of a formalized, mandatory and prescriptive RFI process.

SDG&E notes that today LSEs may collaborate and negotiate with IOUs for contract assignments because the IOU is a party to the existing contract and must take an active role in understanding the resulting impact to PCIA for all other customers. SDG&E also notes that the proposal to require the IOU to submit any contract assignment agreements to the Commission is consistent with existing practice. This process ensures the terms of the new agreement are in the best interest of customers.

SDG&E does not support newly-proposed exclusions that would prevent assignment of contracts. As a threshold matter, there is no valid rationale for excluding contracts priced above 115% of the MPB or resulting in IOU RPS compliance issue from portfolio optimization activities. All opportunities for optimizing IOU portfolios and reducing costs to customers should be on the table – including portfolio optimization involving contracts with above-market costs. Imposing artificial restraints will hinder rather than facilitate the IOUs' optimization and cost-reduction efforts. Additionally, the MPB is only applicable to certain attributes of a power purchase agreement ("PPA") and therefore would not be relevant as a basis for comparing the cost of the entire contract. It would be improper to compare contract costs to a MPB that reflects only a subset of the products in the PPA.

Contracts, either through contract assignment or buy-outs, may require a one-time payment. Such payments may impact the PABA account such that the change in the PCIA rate is greater than the current PCIA rate change cap of 0.5 cents per kilowatt hour. SDG&E recommends that any payments that results from portfolio optimization be exempted from the PCIA cap calculation in order to avert a significant under collection in PABA that would shift risks to bundled service customers.

SDG&E notes that securitization may be another option for IOU portfolio optimization. Securitization was suggested by parties in Phase 1 of the PCIA proceeding. While not discussed during the WG 3 workshops, securitization should not be excluded from the available options for portfolio optimization. SDG&E requests that the co-leads include a reference to securitization in the workshop report as a potential additional optimization opportunity that may be available in the future.

SDG&E disagrees with the proposal by Protect Our Communities Foundation ("POC") to effectively establish a rebuttable presumption imposing automatic penalties on IOUs for any alleged mismanagement of the portfolio. The default assumption of IOU mismanagement is improper; POC's proposal is neither reasonable nor constructive. Not all "event of default" or "terminations" are in the best interest of the customers. POC's proposal would in essence require the IOU to defend its actions as compared to theoretical outcomes that may have been unavailable to the IOU.

In addition, the proposal to submit a new report on cost savings from such activities is duplicative, unnecessary, and inequitable. The IOUs already report portfolio management activities through various Commission processes. All amendments are discussed with the IOUs' procurement review group ("PRG"), as required by the Commission. To the extent contracts are modified due to active portfolio optimization, the IOUs submit such contract amendments to the Commission for approval or through the IOUs' quarterly compliance reports ("QCRs"), which are reviewed by the Commission. The resulting financial impacts are detailed in the IOUs' energy resource recovery account ("ERRA") filings. These filings are reviewed and scrutinized by parties in open and transparent proceedings. SDG&E does not believe additional reporting, which takes away time from active portfolio management, is necessary. For the reasons stated above, SDG&E does not support POC's proposal for additional reporting.

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DENTONS

John W. Leslie
Partner

john.leslie@dentons.com
D +1 619 699 2536

Dentons US LLP
4655 Executive Drive
Suite 700
San Diego, CA 92121
United States

dentons.com

MEMORANDUM

To: Service List in R.17-06-026 (PCIA)

From: Shell Energy North America (US), L.P. ("Shell Energy")

Date: December 20, 2019

Subject: Informal Comments on the Working Group 3 Issues Raised at the December 11 Workshop

Consistent with the schedule discussed at the December 11, 2019 workshop on Working Group 3 issues, Shell Energy provides informal comments on two of the proposals advanced in the workshop. First, Shell Energy opposes the proposal for a mandatory allocation of each IOU's local RA capacity to all LSEs. Second, Shell Energy comments on the proposal addressing the treatment of RPS supplies that are "bundled" and allocated by the IOUs on a long-term (minimum 10-year) basis.

1. Mandatory Allocation of an IOU's Local RA Capacity: The Working Group 3 proposal includes a provision (page 8 of the PowerPoint presentation) that requires each IOU to allocate all of its local RA capacity to all LSEs (through a CAM-like mechanism) based on load share. Under this approach, an IOU would retain its bundled sales customers' proportionate share of the local RA capacity. The remainder of the capacity would be allocated to other LSEs based on an LSE-specific load forecast.

Shell Energy opposes this proposal, for at least three reasons. First, the Commission should be reducing, not increasing, the reach - the breadth - of the CAM. Any expansion of the CAM - or a CAM-like mechanism - discourages LSEs from purchasing their own RA resources. This has become evident as a result of the IOUs' procurement of energy storage (and allocation of the cost through the CAM), because the "automatic limiter" has reduced - to zero - an ESP and CCA's obligation to procure energy storage to meet the energy storage target. Applying a CAM approach to the IOUs' existing local capacity will discourage ESPs and CCAs from developing and procuring their own local RA capacity, as well.

Second, an ESP or a CCA that already has procured its own local RA capacity, including procurement on a long-term basis, should not be forced to accept an allocation of the IOU's local RA capacity. The proposed approach would likely result in the ESP or CCA holding excess local RA capacity. This, in turn, would require the over-resourced LSE to re-sell its excess local RA capacity to mitigate stranded costs. This approach would cause the LSE to bear stranded costs disproportionate to the stranded costs borne by other LSEs. The proposed approach has the potential to place an LSE in a competitively disadvantaged position if the LSE has obtained its own local RA capacity.

Third, it is not enough that the proposal provides that an LSE may "trade" its excess local RA capacity to mitigate its stranded costs. Resales of an LSE's excess local RA capacity may or may not enable the LSE to offset its stranded costs. An LSE should not be required to take the market price risk of additional local RA capacity (and the associated cost) foisted upon it by the IOU.

Based on these concerns, Shell Energy opposes a mandatory allocation, to all LSEs, of an IOU's local RA capacity. Shell Energy supports, instead, an approach through which an IOU holds an annual (and more frequent or for longer terms, as appropriate) voluntary bilateral sale or auction process to allocate excess local RA capacity, similar to the proposed annual voluntary allocation of PCIA-eligible RPS energy and system and flexible RA capacity.

2. Treatment of the Long-Term Attribute of RPS Supplies that are Allocated (on a Voluntary Basis) by the IOUs: Shell Energy supports the proposal that provides for preservation of the long-term attribute of an IOU's RPS supplies when the IOU sells a portfolio of RPS energy or RECs from its long-term (10-year) RPS supply contracts. As long as the LSE purchases this portfolio for a term of at least 10 years, the LSE should receive the benefit of the long-term (10-year) attribute for the entire portfolio.

In this connection, the acquiring LSE should be able to claim the long-term attribute for an IOU's "long-term" RPS portfolio even if some of the contracts in the portfolio have terms less than 10 years. As long as the acquiring LSE has made a minimum 10-year procurement commitment, the LSE should be able to claim this RPS energy (and RECs) as eligible to meet the minimum 10-year contract requirement.

This approach is supported by D.17-06-026 (June 29, 2017). In that Decision, the Commission stated as follows: "[I]f the original RPS procurement contract is 10 years or more in duration, the contract will be considered long term for all subsequent extensions. If a short-term RPS procurement contract is amended by an extension of at least 10 continuous years in duration, the contract will be considered a long-term contract from the date of that amendment through the life of the contract." Decision at p. 20. The Decision also stated the following with respect to "repackaged" long-term arrangements: "The use of repackaged long-term contracts is reasonable in the context of the new SB 350 requirements. Such contracts may be used to meet the LT [long-term] requirement, so long as they are truly long term, i.e., the retail seller's contract for its repackaged share of the generation has a duration of at least 10 years." Decision at p. 21.

On this basis, Shell Energy supports the Working Group 3 proposal, including the provision (page 12 of the PowerPoint) that states: "To receive long-term credit, the longest RPS contract in their vintage must have a remaining term of at least 10 years." Only one contract in the IOU's long term portfolio must have a remaining term of at least 10 years in order for the acquiring LSE to be able to claim the long-term attribute for the purchased RPS energy and RECs.

Shell Energy looks forward to further discussion regarding these and other Working Group 3 issues.

Respectfully submitted,

John W. Leslie

Attorneys for Shell Energy North America (US), L.P.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #4

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Matthew Freedman, Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

December 20, 2019

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #4

TURN offers the following comments on certain issues reviewed in the 4th workshop of Working Group 3 (WG 3) on December 11, regarding portfolio optimization and cost reduction, and allocation and auction. Citations refer to slides presented at the 4th workshop (Presentation).

<u>Allocations of long-term contract compliance attributes</u>

The Presentation proposes to allow any LSE to accept their entire allocation of RPS-eligible procurement within the IOU portfolio (subject to adjustments for IOU portfolio optimization activities). Assuming that there is at least one contract within the allocation with a remaining forward duration of at least 10 years, the working group proposes that the entire allocated portfolio quantity count towards the long-term contract compliance obligations established under Public Utilities Code §399.13(b).[1]

Based on a review of the proposal, TURN is concerned that some of the individual contracts within the portfolio will not have forward durations of at least 10 years at the time the LSE elects to receive the allocation. TURN requested data from each IOU on the prospective durations of RPS-eligible contracts that would be included in portfolio allocations. PG&E and SCE responded to this request just as these comments were due. TURN has not been able to adequately review or analyze this data. Without more opportunity to review comprehensive data from all IOUs, it is difficult to assess what portion of the portfolio would be comprised of contracts that have less than 10 years remaining if an LSE were to take its allocation beginning in 2021.

While TURN recognizes that each LSE would make a commitment of not less than 10 years its entire allocation, that allocation is comprised of a large number of individual contracts. Some of those contracts would not qualify as long-term if they were

[1] Presentation, page 12.

remarketed in a forward sale. This fact complicates any assessment as to whether the quantities should qualify as long-term when bundled within a package of deals that, taken together, runs more than 10 years in duration.

In 2014 the Commission declined to authorize cost recovery for "long-term" contracts proposed by PG&E that would have provided 90% of total deliveries in the first year and spread the remaining deliveries over the following nine years.[2] That rejection was based in large part on TURN's critique that PG&E attempted to circumvent the long-term contracting requirement by entering into a "10-year" contract that was functionally a short-term arrangement.[3] While the proposed PCIA portfolio allocation proposal would not result in the same unbalanced delivery schedule included in PG&E contracts rejected by the Commission, it does raise questions about the types of arrangements that would satisfy the RPS long-term contract requirement.

Due to the unique circumstances associated with the PCIA portfolio allocation, the Working Group should clarify that the requested treatment of long-term contract attributes under this proposal would only apply to PCIA portfolio allocation. To avoid the potential for abuse, the Commission must clarify that other market participants should not expect to receive RPS long-term contract credit for bilateral arrangements that include a mix of short and long-term commitments.

Any voluntary allocation of RPS or GHG-free resources must be structured as a forward sale of a bundled product

The proposed voluntary allocation of RPS and GHG-free resources would allow LSEs to accept an assignment of a share of the IOU portfolio. In prior comments, TURN identified the need for the WG3 proposal to conform to existing conventions relating to

[2] PG&E Advice Letters 4299-E, 4300-E, 4301-E; The Commission rejected Draft Resolution E-4649 that would have approved the contracts.
[3] TURN/CUE protest of PG&E AL 4299-E, 4300-E, 4301-E, October 30, 2013; TURN comments on Draft Resolution E-4649, March 27, 2014.

the forward sale of bundled products. The Presentation does not explicitly conform the allocation to the forward sale requirements.[4]

In prior comments, TURN expressed concern about any initiative to create a new class of unbundled GHG-free attributes that can be traded separately from the electricity generated by the associated units. Any such scheme would run afoul of both the Clean System Power methodology used in the Integrated Resource Planning (IRP) process and the California Energy Commission's Power Source Disclosure Program (PSDP). Neither program allows LSEs to acquire unbundled attributes that can be used to offset portfolio GHG emissions for reporting purposes. The final proposal should explicitly state that all allocated products would be conveyed on a forward basis and include attributes bundled with the associated electricity from the underlying generator to ensure that there is no conflict with the IRP and PSDP protocols.

TURN appreciates the opportunity to submit these comments.

Respectfully submitted,

MATTHEW FREEDMAN

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Matthew Freedman
Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: December 20, 2019

[4] Presentation slides 8, 11.

Appendix F

EXTERNAL ENGAGEMENT

External Engagement

The WG 3 Co-Chairs provided parties to R.17-06-026 with various means of involvement and engaged in a number of conversations. Below the Co-Chairs summarize the methods used to engage with and seek feedback from parties to the proceeding.

A. Workshops

As required by the Phase 2 Scoping Memo, the WG 3 Co-Chairs held four workshops to brief parties to the proceeding about the Co-Chairs' proposals for portfolio optimization, active management of utility portfolios, transition to new standards, and shareholder responsibility for portfolio mismanagement. Below the Co-Chairs summarize each of the workshops held by WG 3.

1. First Workshop – Strawman for Excess Sales

The First Workshop was held on April 29, 2019 from 1:30 – 3:30 PM at the Pacific Energy Center in San Francisco, CA. Approximately 47 parties attended in person and 39 parties participated remotely via WebEx. The First Workshop focused primarily on the straw proposal for identifying and offering for sale any "excess" RA and RPS resources in the IOUs' portfolios. Commercial Energy also discussed its concept for the VAAC. The First Workshop presentation is attached to the First Progress Report of WG 3.

Parties were asked to serve written comments in response to the topics presented at the First Workshop by May 10, 2019. Informal comments were received from 10 parties: Alliance for Retail Energy Markets ("AReM"), California Large Energy Consumers Association ("CLECA"), City of San Diego, NextEra Energy, PG&E, Protect Our Communities Foundation ("POC"), Public Advocates Office ("Cal PA"), San Jose Clean Energy ("SJCE"), Shell Energy ("Shell"), and The Utilities Consumers' Action Network ("UCAN"). The informal comments received in response to the First Workshop are attached to the First Progress Report of WG 3.

2. Second Workshop – System and Flex RA Excess Sales Proposal; Local RA Allocations; GHG-Free Allocations; and Voluntary Allocation and Auction Clearinghouse Proposal

The Co-Chairs held their Second Workshop at SCE's Energy Center in Irwindale, CA on July 25, 2019. The workshop was attended by approximately 27 people, with 22 participating via Skype. The Second Workshop began with a discussion of informal stakeholder feedback from the First Workshop and focused primarily on the following proposals: (1) Excess RA Sales Strawman for System and Flex RA, (2) Local RA Allocation Approach, (3) GHG-Free Allocation Approach, and (4) Commercial's VAAC Strawman. The Second Workshop presentation is attached to the Second Progress Report of WG 3.

The Co-Chairs invited informal comments following the Second Workshop, and six parties provided comments: AReM, Direct Access Customer Coalition ("DACC"), PG&E, POC, Cal PA, and UCAN. The informal comments are attached to the Second Progress Report of WG 3. The Co-Chairs elected to submit a response which is also attached to the Second Progress Report.

3. Third Workshop – RPS and System and Flex RA Voluntary Allocation & Market Offer Proposals

The Co-Chairs' Third Workshop was held on October 17, 2019 at the Commission's Auditorium in San Francisco, CA with approximately 35 people attending in-person, and another 15 via Skype. The Third Workshop began with a recap of the positions presented at the Second Workshop, along with several updates to refine the Local RA and GHG-free energy allocation proposals. The Co-Chair panel introduced the concept of the VAMO framework for System and Flex RA and RPS energy. Finally, the Co-Chairs presented two alternative frameworks for how ratemaking could be modified to accommodate the VAMO frameworks. The Third Workshop presentation is attached as Appendix A.

As with previous workshops, the Co-Chairs sought informal comments. Comments were received from eight parties: AReM, American Wind Energy Association of California ("AWEA") jointly with the Large-Scale Solar Association ("LSA"), DACC, PG&E, POC, San Diego Gas & Electric Company ("SDG&E"), SJCE, and TURN. The informal comments received in response to the Third Workshop are attached as Appendix B.

4. **Fourth Workshop – Refinement of Issue 1 Proposals; Issues 2-4**

The final, Fourth Workshop was held on December 11, 2019 at the Commission's Auditorium in San Francisco, CA. About 20 people attended in person and another 15 via Skype. The Fourth Workshop commenced with a brief recap of the previously articulated positions and provided updates to certain aspects of the RPS energy, GHG-free energy, and System and Flex RA proposals to simplify the proposals and accommodate stakeholder feedback. Following this discussion on the WG 3 Issue 1 topics, the Co-Chairs proceeded to discuss Issues 2 through 4.

Regarding Issue 2, the Co-Chairs presented on the existing framework for IOU portfolio optimization activities, with a consensus view that the IOUs should continue performing such activities. The Co-Chairs then presented a new proposal in which the IOUs would canvas their portfolios to gauge interest in doing a contract assignment with a third-party and/or terminations, which could include proposals to buyout contracts, with the intent of reducing the overall PCIA rate. For Issue 3, the Co-Chairs identified no major transition requirements that had not already been presented in other workshops. Finally, for Issue 4, the Co-Chairs proposed no changes to the existing shareholder responsibility framework, but CalCCA presented their proposal that additional reporting should be required in the ERRA Review of Operations application to report cost savings related to portfolio optimization activities and any material events of default, including whether any termination rights presented themselves and any actions taken with respect thereto. The Fourth Workshop presentation is attached as Appendix D.

The Co-Chairs requested informal comments by December 20, 2019. Comments were received from nine parties: AReM, Coalition of California Utility Employees ("CUE"), Cal PA, NextEra Energy, PG&E, POC, SDG&E, Shell, and TURN. The informal comments received in response to the Fourth Workshop are attached as Appendix E.

B. **Additional Engagement**

In addition to the Workshops, the Co-Chairs sought to provide information to and receive feedback from stakeholders through a variety of means. The Co-Chairs summarize their engagement with other parties below.

1. <u>Informal Comments</u>

Following each of the four workshops, the Co-Chairs sought the feedback and perspectives of stakeholders to the WG 3 process via informal comments submitted to the proceeding's service list. The informal comments proved valuable for the Co-Chairs, as it became evident where there was broad alignment for or against specific proposals put forth by the Co-Chairs, and where perspectives might differ among the third parties. The Co-Chairs sought to be responsive to parties' comments and used the feedback to inform their respective positions and achieve alignment where the Co-Chairs may have previously differed.

Following the Third Workshop, the Co-Chairs also sought feedback prospectively from the stakeholders to the proceeding. The Co-Chairs had identified that there would not be much time remaining to explore Issues 2 through 4 prior to the Fourth Workshop and had not identified any material topics to date. Thus, the Co-Chairs solicited input from the stakeholders at the Third Workshop to proactively submit any proposals they might have relating to Issues 2 through 4 for consideration by WG 3. The informal comments received on Issues 2 to 4 are attached as Appendix C.

2. <u>SharePoint Site</u>

In response to informal comments submitted following the Second Workshop, the Co-Chairs established a public SharePoint site to facilitate greater communication and transparency with the stakeholders participating in the WG 3 process. On September 5, 2019, SCE sent an email to the R.17-06-026 service list notifying parties of the publication of the WG 3 SharePoint site, which was hosted by SCE. A second email was distributed through SharePoint, granting access to members of the service list to the site. Materials on the SharePoint site include: (1) the Phase 2 Scoping Ruling, (2) the four WG 3 workshop presentations, (3) a video recording of the Second Workshop, (4) parties' informal comments to the four WG 3 workshops and the Co-

Chairs' request for proposals regarding Issues 2 through 4, (5) the two WG 3 progress reports, (6) the Procurement Process Reference Guide, (7) various WG 3 meeting agendas, and (8) a WG 3 draft project plan. The materials on the SharePoint site were updated as new materials became available, or as material changes unfolded with regards to the WG 3 project plan.

3. Direct Engagement with Stakeholders

In addition to the efforts the Co-Chairs undertook to prepare for and engage with stakeholders in the public workshops, the Co-Chairs also engaged in various discussions directly with key stakeholders in the WG 3 process. The Co-Chairs found this engagement to be very useful for soliciting feedback from third parties, exploring parties' concerns, and identifying alternative paths forward, as necessary.

a) Community Choice Aggregators

Acting simultaneously as one of the Co-Chairs and as a representative of the diverse group of CCA parties, CalCCA was intimately involved in seeking regular and frequent feedback from the many CCAs it represents. CalCCA held weekly meetings with representatives from the individual CCAs during which it presented the latest points of discussion among the Co-Chairs, sought feedback and proposals from its constituents, and sought consensus on positions to advocate for among the Co-Chairs. On a periodic basis, CalCCA briefed its board, composed of representatives of the cities and communities that its CCAs serve, to receive approval to accept certain positions on behalf of all of the members. Despite various differing points of view, CalCCA was able to identify consensus proposals amongst the various CCA parties, while representing their diverse interests.

b) Investor-Owned Utilities

SCE was designated the IOU Co-Chair within the Phase 2 Scoping Memo. The IOUs held calls at least twice a week throughout Phase 2 of the PCIA proceeding to discuss the proposals developed by the Co-Chairs and any cross-over issues with the ERRA, IRP, and the RA proceedings. Additionally, the IOUs' officers were briefed weekly on key updates and proposals requiring decisions by management to move forward. In addition to these multiple weekly calls, the IOUs also met several times in-person to conduct deep dives into the materials of each of the Working Groups. Typically, these sessions were held prior to workshops in order to ensure consistent understanding of the positions being advocated for, alignment on those positions, and to discuss next steps.

c) Other Load-Serving Entities

Commercial Energy generally represented its own interests in the PCIA case and WG 3, and it believes that those interests mirror the voice of its customers. However, in the interest of facilitating a broader discussion, Commercial held occasional calls and communicated by email with other LSEs, notably Direct Access ("DA") providers and suppliers, including Shell, AReM, and DACC, to discuss proposals and concepts developed by the Co-Chairs in WG 3. Commercial has not attempted to create a single consensus position among these LSEs out of concerns that a party (possibly the IOUs or the CCAs) might raise a claim of restraint of trade. Neither of those parties or their constituents face the same risk as ESPs and their customers. These calls were intended to increase parties' understanding of the specific issues other LSEs have raised and how WG 3 might address them. On more than one occasion, the other LSEs could not agree on specific features in the joint proposal(s) of the WG 3 Co-Chairs and have provided comments to that effect. Similarly, Commercial voiced the concerns raised by other LSEs, but was not always able to find a middle ground with SCE and/or CalCCA.

d) Protect Our Communities

In their informal comments regarding the Second Workshop, POC and UCAN identified concerns with the amount of transparency being provided by the Co-Chairs regarding the overall WG 3 process. POC sought to be included in the WG 3 Co-Chair weekly meetings but the Co-Chairs decided that given the substantial progress made to date and the detailed background needed to understand how consensus was achieved on each of the proposals, it would be unwieldy to add parties who have not been part of these detailed discussions. In an effort to be responsive to the concerns raised by POC regarding transparency, the Co-Chairs established a

SharePoint site to which the Co-Chairs published meeting agendas and a project plan laying out the proposed scope and timeline for the remainder of the WG 3 process.

Following the Third Workshop, POC provided informal comments proposing (1) a sunset of the PCIA within 5 years of each customer vintage's departure, (2) the prioritization of full resource removal from IOUs' portfolios, and (3) that the IOUs should be subject to automatic penalties for failing to adhere to the established timelines and requirements in administering the final PCIA WG 3 process, as ruled upon by the Commission. POC explained its proposals in more detail to the Co-Chairs during an hour-long phone call on November 19, 2019. The Co-Chairs jointly provided feedback as to the challenges and impacts associated with the proposals.

POC also spoke to its proposals at the Fourth Workshop and expressed interest in extending the time for the WG 3 process to continue discussions around appropriate shareholder responsibility within the PCIA process.

e) The Utility Reform Network

In its informal comments to the Third Workshop, TURN expressed concerns over SCE's proposed treatment of long-term RPS attributes, and urged the conveyance of RPS and GHG-free energy on a forward basis to comply with existing statutory requirements. The Co-Chairs held a conference call with TURN on November 15, 2019 to discuss the proposed mechanics related to an allocation and sale of RPS and preserving the long-term attributes. TURN expressed concern over short-term allocation decisions conveying long-term benefits. The conversation with TURN was beneficial for the Co-Chairs to understand concerns related to preservation of long-term attributes. Accordingly, the Co-Chairs presented a consensus, modified proposal for the treatment of long-term RPS attributes at the Fourth Workshop, based in part upon the feedback received from TURN.

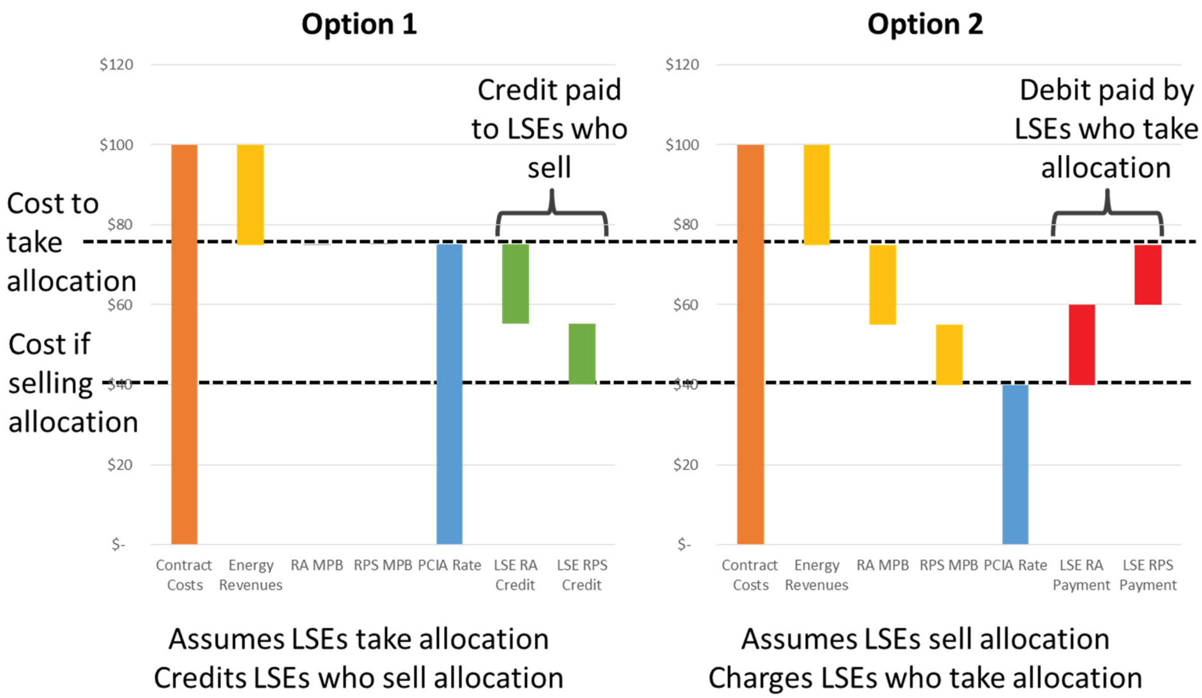
f) California Public Utilities Commission's Energy Division

Following the Third Workshop, the assigned ED staffers (Dina Mackin and Sasha Cole) reached out to the Co-Chairs to inquire whether a meeting might be possible to walk them through the proposals put forth within WG 3. On November 18, 2019, the Co-Chairs met in person with Dina Mackin and Sasha Cole at SCE's offices in San Francisco, CA. The Co-Chairs walked them through the Second and Third Workshop presentations, addressing questions, providing additional background, and receiving feedback on the process and proposals.

Appendix G

COMPARISON OF RATEMAKING APPROACHES

COMPARISON OF RATEMAKING APPROACHES



Appendix H

END-TO-END WG 3 ALLOCATION AND MARKET OFFER EXAMPLE

End-to-End WG 3 Allocation and Market Offer Example

This Appendix provides an end-to-end example of an illustrative IOU's PCIA-eligible portfolio that is made available for allocation among the IOU and four other PCIA-eligible LSEs. This example illustrates how each of the WG 3 proposals for Local RA, System and Flex RA, RPS energy, and GHG-free energy work, including the determination of vintaged peak- (MW) and annual- (MWh) load shares, allocations, re-allocations, ability to count attributes towards IRP, availability of attributes for the Market Offer, selection of offers, Market Offer revenue allocation, impact upon rates, and LSEs' total cost responsibility. The following narrative serves as a guide to understand what takes place within each calculation and to provide additional context around how the results in each table are to be interpreted.

This Excel workbook demonstrates only the mechanism for determining the impact of the first year's allocation elections for each product type. This workbook does not account for changes to allocation positions that would occur in the real world due to variations in resource's NQC or EFC values, portfolio optimization activities undertaken by the IOUs, contract management activities, resource production variability, changes in LSEs' load shares from year to year, regulatory changes, etc. Further, this workbook has several simplifications embedded for easier understanding. For example, the Flex RA product is not modeled, as it would follow the same process as System RA. The spring System RA Market Offer process is not modeled as it would follow the same methodology as the fall Market Offer process, and since there are no changes in position, there would not be much added value in modeling a second Market Offer process. Forecasted coincident peak loads are identified only as the annual peak load, rather than each month's coincident peak load. No true-up of the volumes and product MPBs is performed at year end to account for the actual payments LSEs taking allocations would need to make. These simplifications are called out throughout the following narrative to illustrate where additional complexity would otherwise arise.

For reference, in the Excel workbook, blue text represents hard-coded values, green text represents values inserted from another table within the workbook, and black text represent calculated values. Certain cells are shaded in green or in red to indicate that the calculations are working correctly or incorrectly, respectively, to check that the workbook has been properly programmed.

Table 1. <u>LSE Assumptions</u>

Table 1 presents the assumptions for each of the LSEs within the model IOU's service territory. Column B identifies the vintage corresponding to the LSEs' customers' departure dates. If an LSE were to have more than one vintage of customer departure, each vintage that the LSE serves could be viewed as an independent LSE for purposes of this example. Column C lists the illustrative annual load assumption for each LSE in GWh/yr. Column D lists the illustrative peak load assumption for each LSE in MW. Columns E through I reflect the illustrative elections that these modeled LSEs make with regard to each product type, with 100% reflecting an election to take 100% of the eligible allocation share, and 0% reflecting an election to decline all of the eligible allocation share. The RPS energy and System RA (and Flex RA – although this product is not modeled, as it would follow the same process as System RA) products permit LSEs to elect any 10% increment between 0% and 100%. Additionally, within the RPS elections, LSEs may elect to take a short-term allocation, a long-term allocation, or decline their election. Column E reflects how much of their eligible RPS allocation each LSE elects to accept as a long-term allocation. Column F reflects the LSEs' short-term allocation elections. The difference between 100% and the sum of the short-term and long-term allocation elections reflects the amount each LSE elects to decline from their RPS allocation.

Table 2. <u>LSEs' Vintaged Annual Load Shares</u>

Table 2 illustrates the methodology used for determining an LSE's vintaged annual (MWh) load share. Each row corresponds to a specific LSE and each column corresponds to a specific PCIA vintage. Within the table, each LSE's annual load is listed for each contract vintage in which it is eligible to participate, based upon its customers' departure date from the

IOU. For example, LSE A's customers departed in 2009, so LSE A is eligible to participate in the CTC-Eligible and 2004-2009 vintages only. LSE B's customers departed in 2014, so it is eligible for all PCIA vintages prior to 2014. The LSEs' loads for each vintage are summed in Row 11 and provide the basis for calculating each LSE's share of the total vintage load.

Table 3. <u>LSEs' Vintaged Annual Load Share Percentages</u>

Table 3 translates Table 2 into percentages of annual vintage load. Each LSE's load for each vintage is divided by the total eligible LSE load within that vintage (from Row 11) to calculate the LSE's vintaged annual load share. These LSE-specific vintaged annual load shares will be used to allocate the RPS and GHG-free energy.

Table 4. <u>LSEs' Vintaged Coincident Peak Load Shares</u>

Table 4 is similar to Table 2, but is used to calculate LSEs' vintaged coincident peak-(MW) load shares. As with Table 2, the LSEs' peak loads are mapped to each contract vintage in which the LSE is eligible to participate, based upon its customers' departure date. Row 11 calculates the total coincident peak load of all the LSEs eligible for the vintage. For the allocations of System and Flex RA, the forecasted, vintaged, monthly, coincident peak-load shares will be used, as per the existing RA and CAM processes. However, in this example, for simplification purposes, only the forecasted, vintaged, *annual*, coincident peak-load shares are modeled. For allocations of Local RA, the forecasted, vintaged, annual, coincident peak-load shares would be used for the CPUC showing, but for CAISO the forecasted, vintaged, monthly, coincident peak-load shares would be used.

Table 5. <u>LSEs' Vintaged Coincident Peak Load Share Percentages</u>

Table 5 is similar to Table 3, as it translates Table 4 into percentages of coincident peak load. Each LSE's peak-load for each vintage is divided by the total eligible LSE peak-load within that vintage (from Row 11) to calculate each LSE's vintaged, coincident peak-load share. These LSE-specific vintaged, coincident peak-load shares will be used to allocate the PCIA-eligible Local, System, and Flexible RA attributes.

Table 6. Model IOU Portfolio

Table 6 presents an illustrative IOU portfolio of PCIA-eligible resources. These portfolio resources will be used throughout this end-to-end example to illustrate how the resources' attributes are allocated among the PCIA-eligible LSEs. Column A provides an identifier for each contract, which will be used throughout the example to reference back to specific contracts or UOG resources. Column B identifies the vintage corresponding to each contract or UOG resource. Column C identifies whether the contract or resource is "Bundled" or "RA-only." "Bundled" contracts are contracts in which the IOU receives energy and capacity benefits, in addition to any other resource attributes, whereas "RA-only" contracts provide the IOU with only RA capacity. Columns D through H identify the specific attributes that the IOU receives under each contract, with "Yes" meaning the IOU receives that column's attribute and "No" meaning the IOU does not receive the attribute. In column H, for GHG-free energy, the type of resource is identified as either "Large Hydro[electric]" or "Nuclear." RPS resources provide GHG-free energy benefits, but those benefits are allocated through the RPS VAMO process, rather than the GHG-free energy voluntary allocation process, and are thus identified as "No" in the GHG-free energy column. Columns I and J identify the price paid by the IOU for the contract or UOG resource according to either a bundled PPA price (in $/MWh) (in Column I) or an RA price (in $/kW-month) (in Column J). Column K corresponds to the contracts' or UOG resources' online dates. Note that the online dates may be several years after the date indicated by the vintage, as new generation resources may take a few years to come online after contract execution. Contract execution date is the milestone used for determining the contract's vintage. Column L indicates the term of the contract or expected life of the UOG resource, in years. Column M is calculated by adding the term of the contract or life of UOG resource to the online date to determine the expected contract end date or decommissioning date for UOG resources. Column N indicates the technology of the generating resource, which is used to determine whether the resource is considered RPS-eligible or falls into the Large Hydro or Nuclear GHG-free energy pools. Column O indicates the resources' installed AC capacity (in MW), which is used to determine the expected annual energy production (in GWh) in Column P and the amount of RA capacity available from the resource in Table 33, based upon the technology of the resource in Column N and the resources' Effective Load Carrying Capacity ("ELCC") in Table 32.

Table 7. **<u>GHG-Free, Large Hydro Position by Contract</u>**

Table 7 shows the first step for how the GHG-free energy allocations work. Each large hydroelectric resource that is identified from Column H on Table 6 has its PCIA vintage identified from Column B on Table 6. The expected annual energy production from Column P on Table 6 is mapped to the delivery years identified in Row 4 based upon the Online Date in Column K and Termination Date in Column M, both on Table 6. For simplification purposes, each contract is assumed to last for the full delivery year. Row 24 calculates the total energy production from GHG-free energy resources in each delivery year.

Table 8. **<u>GHG-Free, Large Hydro Position by Vintage</u>**

Table 8 sums the GHG-free energy production from each delivery year for each contract vintage identified in Column B of Table 7. This identifies the vintage-specific GHG-free energy attributes available for allocation to each LSE on the basis of their customers' departure vintages.

Table 9. **<u>GHG-Free, Large Hydro Allocation Eligibility</u>**

Table 9 demonstrates the portion of the IOU's PCIA-eligible GHG-free energy portfolio that each LSE would be eligible to receive in each delivery year based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. This can also be seen as the amount of GHG-free energy procurement credit that each LSE would be able to count towards its IRP Clean Net Short procurement targets, however in implementation the IRP may elect to distinguish LSEs' forecasted annual load shares for each year, rather than applying just the prompt year's forecast as in this simplified example.

The calculation of each LSE's eligible share is performed by multiplying the IOU's portfolio generation in each vintage in each delivery year from Table 8 by each LSE's forecasted vintaged annual load share from Table 3, and then summing across all vintages to determine each

LSE's total share of the GHG-free energy product. In the Excel file, this calculation is simplified by using a SUMPRODUCT function.

For reference, the SUMPRODUCT function works by multiplying the individual components of each array that correspond to the same position in the array and then summing all of the products together. For example, Cell B5 (i.e., the IOU's 2023 GHG-free energy allocation share of the PCIA-eligible portfolio) is calculated according to the following formula:

*= [Vintaged portfolio generation] * [LSE vintaged* annual *load share]*

*= [920, 0, 0, …, 0] * [66%, 66%, 76%, …, 100%]*

= 920 x 66% + 0 x 66% + 0 x 76% + … + 0 x 100%

= 605 GWh

Table 10. **Large Hydro Allocations Accepted**

Table 10 evaluates the actual deliveries of GHG-free energy that each LSE elects for the prompt year (*i.e.,* 2023). The allocation election that each LSE makes, from Table 1, is multiplied by the share of the GHG-free energy production that the LSE is eligible for in 2023, from Table 9. In the example, LSE B elected to decline its allocation, and thus there is an amount of unallocated large hydroelectric energy identified in Row 22.

Table 11. **Large Hydro Re-Allocation**

Table 11 determines how to re-allocate the unallocated GHG-free energy that was declined by LSE B. Column F calculates the re-allocation percentage, which is equal to the volumes of large hydroelectric energy that each LSE elected to accept divided by the total volume of allocated large hydroelectric energy. This is an equivalent percentage to the LSE's forecasted, vintaged annual load relative to the forecasted, vintaged annual load of all other LSEs that elected to take their allocations. Column G calculates how much large hydroelectric energy should be allocated to each LSE by multiplying the volume of unallocated large hydroelectric energy by each LSE's re-allocation percentage.

Table 12. <u>Total Large Hydro Allocations</u>

Table 12 summarizes how much large hydroelectric energy each LSE would be expected to receive based upon the forecasted generation and their forecasted annual load shares. It sums the initially allocated volumes with the re-allocated volumes to determine the total volume of GHG-free, large hydroelectric energy for each LSE.

Table 13. <u>GHG-Free, Nuclear Position by Contract</u>

Table 13 commences the assessment of how much GHG-free, nuclear energy each LSE will be forecasted to receive based upon their allocation elections. Table 13 functions in a similar manner to Table 7 by identifying the expected annual energy production from all nuclear resources in the IOU's portfolio by contract for the term of the contract or life of the UOG asset. The resource's vintage is identified to facilitate aggregation by vintage in Table 14. As with Table 7, the example is simplified to assume that the resource is available for the entire delivery year.

Table 14. <u>GHG-Free, Nuclear Position by Vintage</u>

Table 14 sums all of the nuclear energy production in each year by vintage. This table functions in the same fashion as Table 8.

Table 15. <u>GHG-Free, Nuclear Allocation Eligibility</u>

Table 15 calculates each LSE's eligible share of the nuclear energy production based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. As with Table 9, these eligible delivery amounts would be equivalent to the amount of GHG-free, nuclear energy production that each LSE may claim in IRP for CNS purposes. The calculation functions in the same way as in Table 9.

Table 16. <u>Nuclear Allocations Accepted</u>

Table 16 determines the initial nuclear energy allocation volumes that each LSE would receive based upon their allocation elections, as identified in Table 1. The nuclear allocation election is multiplied by the forecasted nuclear generation for 2023 in Table 15. In this example, LSEs B, C, and D elected to decline their nuclear allocations, so there is unallocated nuclear energy.

Table 17. Nuclear Re-Allocations

Table 17 calculates how the unallocated nuclear energy is to be re-allocated among the LSEs choosing to take their allocation of nuclear energy. As with Table 11, each LSE's allocated volume of nuclear energy is divided by the total allocated volume of nuclear energy to determine the re-allocation percentage. This re-allocation percentage for each LSE is multiplied by the total unallocated nuclear energy volume to determine how much nuclear energy is re-allocated to each LSE.

Table 18. Total Nuclear Allocation

Table 18 summarizes how much GHG-free, nuclear energy each LSE would be forecasted to receive based upon its allocation elections and the decisions of other LSEs around their allocation elections. The initial allocation volumes are summed with the re-allocated volumes for each LSE to determine each LSE's forecasted total nuclear energy allocation.

Table 19. RPS Energy Position by Contract

Like Tables 7 and 13, Table 19 calculates how much RPS energy is available in each delivery year from each contract, and identifies the contracts' vintages so that the forecasted RPS generation can be summed by vintage in Table 20. Again, the example is simplified to assume that the resource is available for the entire delivery year.

Table 20. RPS Energy Position by Vintage

Like Tables 8 and 14, Table 20 sums the RPS energy available in each delivery year by contract vintage. This will be used in Table 21 to determine each LSE's eligible share of the PCIA-eligible RPS portfolio on the basis of their customers' departure date.

Table 21. RPS Energy Allocation Eligibility

Like Tables 9 and 15, Table 21 determines the eligible share of the IOU's PCIA-eligible RPS energy position that each LSE would be forecasted to receive based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. The calculations function the same in Table 21 as in Tables 9 and 15.

These forecasted, eligible allocations of RPS energy would not necessarily be the volumes that each LSE would be able to count in IRP, however. RPS is a bit different from other products for IRP treatment, as the results of the Market Offer must be evaluated to determine how much IRP credit each LSE may receive, as long-term sales may remove PCIA-eligible RPS energy from the portfolio for allocation to the LSEs that had declined a portion of their eligible allocation shares.

Table 22. <u>RPS Energy Long-Term Allocations Accepted</u>

Table 22 evaluates the forecasted volumes of RPS energy that each LSE has elected to accept as a long-term allocation. As Table 21 has determined each LSE's total eligibility for allocations, Table 22 simply multiplies each LSE's eligible RPS energy allocation volume in each delivery year by that LSE's long-term allocation election percentage from Table 1.

Table 23. <u>RPS Energy Short-Term Allocations Accepted</u>

Table 23 evaluates the forecasted volumes of RPS energy that each LSE has elected to accept as a short-term allocation, i.e., just for the prompt year, 2023. Table 23 multiplies each LSE's total eligible RPS energy allocation volumes from Table 21 by that LSE's short-term RPS allocation election percentage from Table 1 to determine the volumes that LSE would be expected to receive as a short-term allocation in 2023.

Table 24. <u>Total RPS Energy Allocations Accepted</u>

Table 24 determines the total RPS energy volumes that each LSE would be expected to receive at the RPS MPB in each delivery year by summing the long-term and short-term allocation volumes from Tables 22 and 23, respectively, for each LSE.

Table 25. <u>RPS Allocation Payments</u>

Table 25 calculates the estimated allocation payments that each LSE would owe for its purchase of the allocated RPS energy volumes in 2023. Table 25 multiplies the 2023 forecasted RPS energy allocation volumes from Table 24 by the forecasted RPS MPB from Table 53 to calculate the forecasted allocation payments. It is important to note that the LSEs' payments would be subject to the actual RPS energy deliveries realized throughout the delivery year, and would be trued up according to the actual MPB near the end of the delivery year.

Table 26. <u>Distribution of RPS Allocation Payments Across Vintages</u>

Table 26 determines how the revenues realized from LSEs' RPS energy allocation purchases in 2023 are to be distributed to the PABA vintaged sub-accounts. The total RPS energy expected to be produced in 2023 within each vintage is multiplied by the percentage of each vintage that is to be allocated and is further multiplied by the forecasted RPS MPB for 2023 to determine the forecasted total RPS allocation payments within each vintage for 2023. The percentage of each vintage to be allocated is determined by multiplying each LSE's total allocation election percentage (i.e., the sum of short- and long-term allocation election percentages) by each LSE's forecasted annual load share, and summing the resulting LSE-specific percentage for each vintage to determine the total (i.e., across all LSEs) percentage of the RPS energy generation to be allocated within each vintage. These steps for determining the percentage of each vintage to be allocated are simplified in the Excel workbook through the use of the SUMPRODUCT function described in the write-up for Table 9.

Table 27. <u>RPS Allocations Declined</u>

To determine the volumes to be offered in the RPS Market Offer process, Table 27 first determines the forecasted total unallocated RPS energy volumes for 2023, based upon LSEs' elections. To calculate this amount, each LSE's total RPS allocation for 2023, from Table 24, is subtracted from each LSE's eligible RPS allocation volume for 2023, from Table 21. The total volume of RPS energy that is declined across all LSEs, in Row 10, will be the amount of RPS energy that is available for sale in the Market Offer for delivery in 2023.

Table 28. <u>RPS Energy Available for Long Term Market Offer</u>

Table 28 calculates how much RPS energy is available for sale in the Market Offer under long-term (i.e., 10 or more years) contracts. Within each Market Offer, the IOU will offer for sale up to 35% of each LSE's declined allocation, up to a maximum of 35% of each LSE's eligible allocation share. To calculate this, Table 28 calculates the lesser of (i) the volumes declined by each LSE in 2023, in Table 27, and (ii) each LSE's eligible allocation share for each delivery year, in Table 21. This value is then multiplied by the 35% long-term sales cap to calculate the maximum RPS energy volume (attributable to each LSE) that may be sold in each delivery year under a long-term sale. The volumes that may be sold long-term that are attributable to each LSE are then summed to determine the maximum volume that may be offered for sale long-term for each delivery year within the Market Offer, as demonstrated in Row 23. The maximum volumes that may be offered for sale short-term are identified in Row 24, for the prompt year (2023) only. Note that the long-term volumes may be sold as short-term, so the long-term volume is a subset of the short-term volume, and the two volume numbers should not be added together.

Table 29. **RPS Market Offer Bids and Selections**

Table 29 demonstrates the bids received in a mock RPS Market Offer process and demonstrates which bids would have been selected, and what the resulting revenues would be. Each bid is numbered in Column A. Each bid is assigned a mock volume (expressed as a percentage of the RPS energy production available for sale), price (in $/MWh), and term (expressed in years, which may be one year or 10 or more years in length). The bids are ordered from highest to lowest price in order to facilitate the bid selection.

To commence the bid selection process, Column E translates each bid's volume from Column B into a GWh volume based upon whether the bid is short-term (i.e. 1 year in length) or long-term (i.e., 10 or more years in length) and multiplying the bid's volume percentage by the total generation that is available for sale in the short-term (Row 24) or long-term (Row 23) from Table 28. Column F next identifies the volumes that are desired to be purchased within each long-term bid, which are then summed in sequential order from highest to lowest price in Column G to calculate the cumulative long-term bid volumes, up to the maximum long-term volumes available for sale in 2023 from Table 28, Row 23. Similarly, Column H calculates the total cumulative volume bid, in sequential order from highest to lowest offer, including both the long- and short-term contracts, up to the maximum volume available for short-term sale as identified in Table 28, Row 24. Both Columns G and H are needed to ensure that the maximum volume that is available for sale as either long-term or short-term is not exceeded in offer selection.

Column I next calculates whether each bid is "Selected," "Partially Selected," or "Not Selected." A bid is selected if the difference in the total cumulative volume (in Column H) between the current bid and the previous, higher-priced, bid is equal to the current bid's volume. A bid is not selected if the difference in the Total Cumulative Volume in Column H does not increase, indicating that all volumes available for sale in the Market Offer have been sold. A bid is partially selected, meaning only a portion of the bid volumes are selected, based upon the maximum volume remaining available in the Market Offer. Bids that are partially selected are identified by having the incremental increase in the Total Cumulative Volume (Column H) from the previous bid not be equal to the volume desired in the bid. Column J calculates the volume of RPS energy sold under each bid and ensures that the total does not exceed the volumes available within the Market Offer. Column K translates the volumes sold back into percentages, which would be used for contracting purposes under slice-of-generation contracts, which would be identified as short- or long-term pursuant to Column L. The forecasted revenues from each bid that is selected or partially selected are calculated in Column M by multiplying the bid price by the selected volumes. All of the bids' forecasted revenues are summed to determine the total expected revenues from the Market Offer process, which is divided by the volume offered for sale to determine the weighted average price realized in the Market Offer from accepted bids. If unsold volumes existed, those unsold volumes would be factored in to determine the weighted average price realized for revenue allocation purposes in Table 30. Additionally, those unsold volumes of RPS energy would need to be re-allocated among all PCIA-eligible LSEs at $0/MWh on the basis of the LSEs' forecasted, vintaged, annual-load shares. As there are no unsold RPS volumes in this example, and for simplicity purposes, this step is not demonstrated in this example, but the process would follow the example set forth in Tables 48 through 50 for System and Flex RA.

Table 30. RPS Market Offer Revenue Allocation by Vintage

Table 30 calculates how the revenues realized in the RPS Market Offer process are to be allocated across the PABA sub-accounts corresponding to each vintage. In Column B, the declined RPS energy volumes sourced from each vintage are calculated by multiplying each vintage's total expected PCIA-eligible RPS generation by the percentage of each vintage that is declined. The percentage of each vintage that is declined is calculated by first subtracting each LSE's allocation election percentage from 100%, to calculate each LSE's declined allocation election percentage. Second, this value is multiplied by the LSE's annual load share percentage for each vintage to determine the percentage of each vintage declined by each LSE. Third, these values are all summed to calculate the total percentage of each vintage that is declined. Within the Excel model, these three steps are combined into the SUMPRODUCT function, which functions as described in the description for Table 9, above.

The revenues ascribed to each vintage are calculated in Column C and are calculated by multiplying the declined volumes sourced from each vintage (in Column B) by the weighted average price realized in the RPS Market Offer (including unsold volumes) from Table 29.

Table 31. RPS Market Offer Revenue by LSE

While only relevant in the context of Ratemaking Option 1, which was considered but not pursued by the Co-Chairs and is shown for illustrative purposes in Tables 56 to 58, Table 31 calculates the RPS Market Offer revenues attributable to each LSE on the basis of their RPS energy allocation elections. Each LSE's declined RPS energy volumes are identified in Column B. In Column C, each LSE's declined RPS energy volumes from Column B are divided by the total declined RPS energy volumes and then multiplied by the total RPS energy revenues to determine each LSE's pro rata share of the RPS Market Offer revenues.

Table 32. <u>Source of Long-Term RPS Sales</u>

Table 32 identifies from which LSEs' eligible RPS energy allocation shares the long-term RPS energy sales are to be sourced from. The percentage of long-term sales sold in the Market Offer from Cell K17 on Table 29 is multiplied by the portion of each LSE's eligible allocation that is available for long-term sale in the Market Offer, based upon Table 28. The amount of long-term RPS energy sourced from each LSE is important as it informs how much IRP credit that LSE may receive and for ensuring that in future Market Offers that no more than 35% of that LSE's eligible allocation share is offered for sale through long-term contracts.

Table 33. <u>RPS Energy Available for IRP CNS Credit</u>

Table 33 identifies the amount of RPS energy that each LSE may count for IRP Clean Net Short credit. Each LSE's short-term and long-term sales are deducted from the eligible RPS energy allocation volumes to determine the credit that LSE may receive in IRP. Short-term sales will only impact the prompt year (2023 in this example), once they have been executed. Long-term sales will have a lasting impact to reduce the credit the LSE may receive in IRP, as the buyer of the long-term RPS energy in the Market Offer may count the RPS energy towards its IRP requirements.

Table 34. <u>Monthly Effective Load Carrying Capacity</u>

Table 34 demonstrates each technology's Effective Load Carrying Capacity ("ELCC") as identified by the CAISO for each calendar month in 2020. The technology-specific ELCC factors will be used to determine each bundled contract's NQC in Table 35.

Table 35. <u>Monthly Contract NQC Value</u>

Table 35 identifies the available NQC for each contract by month. The installed AC capacity for each contract, from Table 6, is multiplied by the relevant ELCC factor for that contract's technology for the relevant month from Table 34 to determine the NQC. The portfolio's NQC is determined in Row 25 by summing all of the contracts' NQC values in each month.

Table 36. <u>Local RA Position by Contract</u>

Table 36 calculates the monthly PCIA-eligible Local RA position by contract for the multi-year Local RA compliance period (*i.e.*, three years). Each contract that provides Local RA is identified by vintage in Column B, and has its NQC for each calendar month identified for the each month that the contract is active within the IOU's portfolio. The total PCIA-eligible Local RA position for each month is calculated in the bottom row of the table.

Table 37. <u>Local RA Position by Vintage</u>

Table 37 illustrates the PCIA-eligible Local RA position by vintage for the multi-year compliance period. Each month's Local RA position is summed by the contracts' PCIA vintages identified in Column B of Table 36.

Table 38. <u>Local RA Allocations</u>

Table 38 shows the Local RA volumes that each LSE will receive through its allocation, and that each LSE may use for IRP credit. Each LSE's forecasted, vintaged, coincident peak-load share for the prompt year, from Table 5, is multiplied by the monthly, vintaged Local RA positions identified on Table 37, and is summed across the vintages to determine the total Local RA volume that each LSE will receive in the allocation. This is performed in the Excel file through the use of the SUMPRODUCT function.

Note that while Table 38 shows the Local RA that would be shown for allocation in the 2022 RA compliance filing year for 2023-25, the Co-Chairs propose that in the first year of implementation in the 2022 RA compliance filing, LSEs would only have 2024 and 2025 Local RA positions allocated. In the 2023 RA compliance filing, LSEs would receive a full three year allocation for 2024 to 2026 showing years.

Additionally, in IRP, LSEs would receive credit for their forecasted share of their forecasted eligible Local RA share through the end of the term of the PCIA vintage, rather than just for the three year period shown in Table 38.

Table 39. System RA Position by Contract

Table 39 summarizes the System RA volumes provided by each contract that provides System RA, but not Local RA. Like Table 36, each contract that provides System RA is identified by vintage in Column B, and has its NQC for each calendar month identified for the each month that the contract is active within the IOU's portfolio over the next three years. The total PCIA-eligible System RA position for each month is calculated in the bottom row of the table. The Flexible RA position would similarly be identified for each contract that provides Flexible RA, but neither Local RA nor System RA.

Table 40. System RA Position by Vintage

Table 40 illustrates the PCIA-eligible System RA position by vintage for the next three years. Each month's System RA position is summed by the contracts' PCIA vintages identified in Column B of Table 39. Flexible RA would similarly be summed across the various contracts' vintages to identify each vintage's Flexible RA position for allocation.

Table 41. System RA Allocation Eligibility

Table 41 identifies the amount of System RA that each LSE would be eligible to receive as an allocation. Each LSE's forecasted, coincident peak-load share for each vintage is multiplied by the relevant vintage's System RA position for each month to determine the volume of System RA capacity that the LSE will receive from that vintage within that month. The LSE's shares of each vintage are all summed together for each month to determine the total position that each LSE would be eligible to receive in each month. This is modeled in Excel using the SUMPRODUCT function.

Again, while Table 41 only shows the three years of forward positions, LSEs would be able to claim their eligible allocation share of the PCIA-eligible System or Flexible RA through the end of their PCIA vintage's term.

Table 42. System RA Allocations Accepted

Table 42 identifies the System RA allocation volumes actually accepted for allocation by each LSE, based upon their allocation elections identified in Table 1. Each LSE's eligible

System RA volumes for each month in the prompt year are multiplied by the LSE's allocation election. LSEs may not make different percentage elections for each month. Only the prompt year (2023) is modeled, as LSEs only make elections and receive allocations for the prompt year. Row 11 calculates the difference between the total System RA position that was available for allocation and the sum of the LSE's allocated System RA volumes to determine how much System RA is available for sale in the Market Offer.

As this end-to-end example does not alter the positions within the IOU's portfolio throughout the course of the year, the example is being simplified to omit the spring Market Offer that System and Flex RA would be subject to in the Co-Chairs proposal. The process for determining the volumes to be sold in the spring Market Offer would be the same as shown in Table 42, but the LSEs' option to decline an allocation would be capped at 50% in the spring, to ensure that any changes to any LSE's vintaged, coincident peak-load share, change in System or Flex RA position due to portfolio optimization, or NQC or EFC updates, etc. would not inhibit the ability to fulfill any LSE's election for an allocation by selling too much System or Flex RA capacity in the spring Market Offer.

Table 43. <u>Allocation Payments by LSE</u>

Table 43 calculates the forecasted payment that each LSE accepting an allocation would need to pay for each month of the compliance year. The System RA volume allocated in each month to each LSE is multiplied by the forecasted System RA MPB to determine the expected payment for each month by each LSE. The amounts owed in each month are summed to determine the total owed by each LSE for the compliance year, subject to the true-up of the MPB at the end of the year.

Table 44. <u>Distribution of System RA Allocation Payments Across Vintages</u>

Table 44 determines how the revenues realized from LSEs' System RA allocation purchases in 2023 are to be distributed to the PABA vintaged sub-accounts. The total System RA available in each month within each vintage is multiplied by the percentage of each vintage that is to be allocated and is further multiplied by the forecasted System RA MPB for 2023 to determine the forecasted total System RA allocation payments for each month within each vintage for 2023. The percentage of each vintage to be allocated is determined by multiplying each LSE's System RA allocation election percentage by each LSE's forecasted coincident peak-load share of each vintage, and summing the resulting LSE-specific percentage for each vintage to determine the total (*i.e.,* across all LSEs) percentage of the System RA capacity to be allocated within each vintage for each month.

Table 45. <u>Declined System RA</u>

Table 45 identifies the System RA volumes declined by each LSE within each month, which will be pooled and made available for sale within the System RA Market Offer process.

Table 46. <u>System RA Market Offer Bids</u>

Table 46 illustrates the bids received within a mock Market Offer. The bids are assigned a bid number in Column A and each bid is provided an illustrative price (in $/kW-month) and term (identified according to the months marked with a 1). The revenue expected from each bid is calculated in Column P, and is equal to the product of the volume, the price, the number of months purchased, and whether the offer is selected or not (1 or 0, respectively, in Column Q).

To perform the Market Offer selections, Excel's Solver add-in is utilized to maximize the total revenues realized in the Market Offer process, identified in Cell P16. In Solver, Cells Q6:Q15 are to be changed to identify the maximum revenue. Table 47 is used in the calculation to ensure that the total System RA volumes sold in each month do not exceed the volumes available for sale, so Cells C35:N35 are constrained to be less than or equal to Cells C11:N11 in Table 45[1]. Finally, as the selections are binary in nature (either selected or not), an additional constraint is added that makes Cells Q6:Q15 equal a binary outcome (*i.e.*, 0 or 1). Solver is then run, potentially a few times, until the result stabilizes at a maximum revenue amount. The resulting bid selection set is reflected in Column Q, with a 1 indicating the bid was selected and a 0 reflecting that the bid was rejected.

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1 Note this must be manually updated each time Solver runs, since Solver does not save that the reference is on a different tab.

Table 47. <u>System RA Volumes Sold in Market Offer</u>

Table 47 is used within the Solver calculation for Table 44, and demonstrates the results of the Market Offer. Each bid within Table 46 has its volume multiplied by the 1 or 0 corresponding to whether the month is or is not included in the term and the 1 or 0 corresponding to whether the bid was selected or not in Column Q of Table 46. Row 35 sums the volumes sold from each month across all of the selected bids to determine how much capacity was sold in each month.

Table 48. <u>Unsold System RA</u>

Table 48 calculates the amount of System RA that remains unsold following the System RA Market Offer process. The total volume of System RA that is sold in in each month in the Market Offer from Table 47 is subtracted from the total declined volume of System RA in each month from Table 45 to calculate the unsold System RA in each month.

Table 49. <u>Unsold System RA by Vintage</u>

Table 49 distributes the unsold System RA across the PCIA vintages on the basis of the vintages from which the capacity was originally sourced. The monthly, vintaged RA position from Table 40 is multiplied by (i) the percentage of System RA that is declined within each vintage and (ii) the ratio of unsold System RA to declined System RA (*i.e.,* offered for sale) in each month.

Table 50. <u>Unsold System RA Re-Allocation</u>

Table 50 identifies how much of the unsold System RA is re-allocated to each of the PCIA-eligible LSEs. The unsold System RA is re-allocated across all PCIA-eligible LSEs on the basis of their forecasted, vintaged, peak-load share. Accordingly, each LSE's peak-load share is multiplied by the unsold System RA volume within each vintage, from Table 49, and is then summed across the vintages to determine that LSE's total re-allocation of System RA.

Table 51. <u>Total System RA Allocations</u>

Table 51 identifies the total amount of System RA that each LSE receives as an allocation, which is equal to the sum of the LSE's elected allocation share plus the unsold RA that is re-allocated to the LSEs.

Table 52. <u>Market Offer Revenue Allocation across Vintages</u>

Table 52 demonstrates the distribution of the System RA Market Offer revenues across the PABA vintaged sub-accounts. The monthly, vintaged RA position from Table 40 is multiplied by the percentage of System RA that is declined within each vintage and the weighted average price of all RA offered for sale (*i.e.*, the sold and unsold System RA volumes) to determine the revenues attributable to each vintage and each month.

Table 53. <u>Market Offer Revenue Allocation by LSE</u>

As with Table 31, Table 53 is only relevant in the context of Ratemaking Option 1, which was considered but not pursued by the Co-Chairs and is shown for illustrative purposes in Tables 56 to 58. Table 53 identifies the revenues from the System RA Market Offer that are attributable to each LSE based upon their elections to decline their allocations. The total volumes across all of the months in the compliance year are summed for each LSE and multiplied by the average price realized across all System RA offered for sale in the Market Offer process (*i.e.*, the sold and unsold volumes).

Table 54. <u>Market Price Benchmark Assumptions</u>

Table 54 identifies the forecasted Market Price Benchmarks for each product, which would be published in the IOU's ERRA Forecast Application for the prompt year. Each of these MPBs would be trued-up in the next year's IOU ERRA Forecast Application. In the case of System RA and RPS energy this true-up of the respective MPBs will require a true-up payment from the LSEs purchasing allocations. In the case of energy and ancillary services, the actual revenues realized will continue to require a true-up to be realized through PCIA rates.

Table 55. Costs and Energy Revenues by Contract

Table 55 demonstrates the expected annual contract cost, energy revenue, and net above market costs associated with each contract, which is to be used in Table 56 to calculate the costs and energy revenues associated with each vintage.

Table 56. Net Above Market Costs to be Recovered in PCIA Rates by Vintage

Table 56 illustrates the difference in cost recovery through PCIA rates paid by customers between the two ratemaking options considered by the Co-Chairs. Each vintage has its total contract and UOG costs identified in Column B and the total energy revenue reflected in Column C. The net above market cost for each vintage is reflected in Column D, and reflects the above market cost that would be recovered through PCIA rates under Ratemaking Option 1, wherein no value would be attributed to any of the resource attribute MPBs. The revenues realized from System and Flex RA allocations (Column E) and System and Flex RA Market Offer sales (Column F) and from RPS energy allocations (Column G) and RPS energy Market Offer sales (Column H) are identified for each vintage and are subtracted from the net above market costs for Ratemaking Option 1 to reflect the net above market costs to be recovered in PCIA rates under Ratemaking Option 2.

Table 57. Illustrative PCIA Rate Calculations

Table 57 demonstrates how the PCIA rates would be calculated for each vintage based upon the two different ratemaking options considered by the Co-Chairs. Each of the net above market costs corresponding to each of the ratemaking options is identified in Columns B and C, from Table 56. Additionally, the total vintaged load across all of the eligible LSEs in each vintage is identified in Column D. The incremental rate relating to each vintage is calculated for Ratemaking Option 1 in Column E and for Ratemaking Option 2 in Column F by dividing the net above market costs for each ratemaking option by the total vintaged load in Column D. The actual rate that would be charged to the customers under each of the ratemaking options is calculated in Columns G and H by summing each incremental rate sequentially.

Table 58. Total Cost Responsibility – Ratemaking Option 1

Table 58 demonstrates the net costs paid by customers and LSEs after accounting for the LSEs' share of revenues credited against the PCIA rates paid by their customers under Ratemaking Option 1. The revenues to be distributed from the IOU to each LSE for the sale of declined RA allocations in the Market Offer is identified from Table 53, and the revenues to be distributed to each LSE for the sale of declined RPS allocations is identified from Table 31. These revenues serve as credits to the LSE to reduce their customers' net payments for PCIA above market costs, as indicated in Column G.

Table 59. Total Cost Responsibility – Ratemaking Option 2

Table 59 demonstrates the total costs paid both by LSEs for the purchase of allocations and their customers for their payment of PCIA rates. The costs to be paid by each LSE for their RA allocations are identified from Table 43 and the costs for RPS energy allocations are identified from Table 25. These allocation payments are added to the LSEs' customers' PCIA rate payments to determine the net costs paid by each LSE and its customers.

Regardless of whether Ratemaking Option 1 or Option 2 is implemented, the net costs borne by customers is the same, as demonstrated by comparing the Net PCIA Cost Responsibility in Column G between Tables 58 and 59.

Table 1

LSE Assumptions

LSE	Vintage	Annual Load (GWh)	Peak Load (MW)	Allocation Elections (1 - Accept, 0 - Decline)				
				RPS Energy (Long-Term)	RPS Energy (Short-Term)	Nuclear Energy	GHG-Free Energy	System RA
IOU	2020	50,000	13,000	100%	0%	100%	100%	100%
A	2004-2009	10,000	2,500	0%	0%	100%	100%	0%
B	2014	3,000	800	0%	0%	0%	0%	50%
C	2018	1,000	300	70%	30%	0%	100%	0%
D	2018	12,000	3,500	50%	0%	0%	100%	80%

Table 2

LSE's Vintaged Annual Load Shares

		Annual Vintaged Loads (GWh)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
A	2004-2009	10,000	10,000	-	-	-	-	-	-	-	-	-	-	-
B	2014	3,000	3,000	3,000	3,000	3,000	3,000	3,000	-	-	-	-	-	-
C	2018	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-	-
D	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	-	-
Total		76,000	76,000	66,000	66,000	66,000	66,000	66,000	63,000	63,000	63,000	63,000	50,000	50,000

Table 3

LSE's Vintaged Annual Load Share Percentages

		Annual Vintaged Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	66%	66%	76%	76%	76%	76%	76%	79%	79%	79%	79%	100%	100%
A	2004-2009	13%	13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2014	4%	4%	5%	5%	5%	5%	5%	0%	0%	0%	0%	0%	0%
C	2018	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%
D	2018	16%	16%	18%	18%	18%	18%	18%	19%	19%	19%	19%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 4

LSE's Vintaged Coincident Peak Load Shares

		Annual Vintaged Peak Loads (MW)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
A	2004-2009	2,500	2,500	-	-	-	-	-	-	-	-	-	-	-
B	2014	800	800	800	800	800	800	800	-	-	-	-	-	-
C	2018	300	300	300	300	300	300	300	300	300	300	300	-	-
D	2018	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	-	-
Total		20,100	20,100	17,600	17,600	17,600	17,600	17,600	16,800	16,800	16,800	16,800	13,000	13,000

Table 5

LSE's Vintaged Coincident Peak Load Share Percentages

		Annual Vintaged Peak Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	65%	65%	74%	74%	74%	74%	74%	77%	77%	77%	77%	100%	100%
A	2004-2009	12%	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2014	4%	4%	5%	5%	5%	5%	5%	0%	0%	0%	0%	0%	0%
C	2018	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%
D	2018	17%	17%	20%	20%	20%	20%	20%	21%	21%	21%	21%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 6
Model IOU Portfolio

Contract #	Vintage	Contract Type	Local RA	System RA	Flex RA	RPS Energy	GHG-Free Energy	PPA Price ($/MWh)	RA Price ($/kW-mo)	Online Date	Term (Years)	Termination Date	Technology	Installed AC Capacity (MW)	Expected Annual Energy Production (GWh)
1	CTC-Eligible	Bundled	Yes	Yes	Yes	No	Large Hydro	$20		1/1/1910	130	1/1/2040	Large Hydro	200	736
2	CTC-Eligible	Bundled	No	Yes	Yes	No	Large Hydro	$25		1/1/1935	100	1/1/2035	Large Hydro	50	184
3	CTC-Eligible	Bundled	Yes	Yes	Yes	No	Nuclear	$32		1/1/1965	70	1/1/2035	Nuclear	1000	8059
4	CTC-Eligible	Bundled	Yes	Yes	Yes	No	No	$35		1/1/1990	40	1/1/2030	Gas CCGT	800	3854
5	2004-2009	Bundled	Yes	Yes	Yes	No	No	$45		1/1/2010	40	1/1/2050	Gas Peaker	50	53
6	2004-2009	Bundled	No	Yes	No	Yes	No	$250		1/1/2011	20	1/1/2031	Wind	90	205
7	2004-2009	Bundled	No	Yes	No	Yes	No	$120		7/1/2011	20	7/1/2031	Geothermal	100	666
8	2010	Bundled	No	Yes	No	Yes	No	$200		1/1/2012	20	1/1/2032	Wind	50	114
9	2011	Bundled	No	Yes	No	Yes	No	$250		1/1/2014	20	1/1/2034	Solar	300	736
10	2014	Bundled	No	Yes	No	Yes	No	$180		1/1/2018	20	1/1/2038	Solar	150	368
11	2015	Bundled	No	Yes	No	Yes	No	$140		1/1/2018	15	1/1/2033	Wind	100	228
12	2016	Bundled	No	Yes	No	Yes	No	$50		1/1/2020	15	1/1/2035	Solar	150	368
13	2017	Bundled	No	Yes	No	Yes	No	$45		1/1/2020	20	1/1/2040	Solar	100	245
14	2017	Bundled	No	Yes	No	Yes	No	$42		1/1/2019	10	1/1/2029	Wind	60	137
15	2017	RA-only	Yes	Yes	No	No	No		$4.50	1/1/2022	2	1/1/2024	Gas Peaker	50	0
16	2018	RA-only	Yes	Yes	Yes	No	No		$5.00	7/1/2022	2	7/1/2024	Gas CCGT	800	0
17	2020	RA-only	Yes	Yes	No	No	No		$3.40	1/1/2023	1	1/1/2024	Gas CCGT	500	0
18	2020	RA-only	No	Yes	Yes	No	No		$5.50	7/1/2023	0.25	10/1/2023	Gas CCGT	300	0
19	2020	RA-only	No	Yes	No	No	No		$3.00	3/1/2023	0.5	8/31/2023	Gas Peaker	100	0

Table 7

GHG-Free, Large Hydro Position by Contract

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	736	736	736	736	736	736	736	736	736	736	736	736	736	736
2	CTC-Eligible	184	184	184	184	184	184	184	184	184	184	184	184	-	-
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 8
GHG-Free, Large Hydro Position by Vintage

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	920	920	920	920	920	920	920	920	920	920	920	920	736	736
2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 9

GHG-Free, Large Hydro Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	605	605	605	605	605	605	605	605	605	605	605	605	484	484
A	121	121	121	121	121	121	121	121	121	121	121	121	97	97
B	36	36	36	36	36	36	36	36	36	36	36	36	29	29
C	12	12	12	12	12	12	12	12	12	12	12	12	10	10
D	145	145	145	145	145	145	145	145	145	145	145	145	116	116
Total	920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 10

Large Hydro Allocations Accepted

LSE	Allocation Election	2023 Large Hydro Allocation (GWh)
IOU	100%	605
A	100%	121
B	0%	-
C	100%	12
D	100%	145
Total		883
Unallocated		36

Table 11

Large Hydro Re-Allocations

LSE	Re-Allocation Percentage	2023 Large Hydro Re-Allocation (GWh)
IOU	68%	25
A	14%	5
B	0%	-
C	1%	0
D	16%	6
Total		36

Table 12

Total Large Hydro Allocations

LSE	2023 Large Hydro Allocation (GWh)
IOU	630
A	126
B	-
C	13
D	151
Total	920

Table 13
GHG-Free, Nuclear Position by Contract (GWh)

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 14

GHG-Free, Nuclear Position by Vintage (GWh)

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-
2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 15

GHG-Free, Nuclear Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	-	-
A	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	-	-
B	318	318	318	318	318	318	318	318	318	318	318	318	-	-
C	106	106	106	106	106	106	106	106	106	106	106	106	-	-
D	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	-	-
Total	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 16

Nuclear Allocations Accepted

LSE	Allocation Election	2023 Nuclear Energy Allocation (GWh)
IOU	100%	5,302
A	100%	1,060
B	0%	-
C	0%	-
D	0%	-
Total		6,363
Unallocated		1,697

Table 17

Nuclear Re-Allocations

LSE	Re-Allocation Percentage	2023 Nuclear Energy Re-Allocation (GWh)
IOU	83%	1,414
A	17%	283
B	0%	-
C	0%	-
D	0%	-
Total		1,697

Table 18

Total Nuclear Allocation

LSE	2023 Nuclear Energy Allocation (GWh)
IOU	6,716
A	1,343
B	-
C	-
D	-
Total	8,059

Table 19

RPS Energy Position by Contract (GWh)

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	205	205	205	205	205	205	205	205	-	-	-	-	-	-
7	2004-2009	666	666	666	666	666	666	666	666	-	-	-	-	-	-
8	2010	114	114	114	114	114	114	114	114	114	-	-	-	-	-
9	2011	736	736	736	736	736	736	736	736	736	736	736	-	-	-
10	2014	368	368	368	368	368	368	368	368	368	368	368	368	368	368
11	2015	228	228	228	228	228	228	228	228	228	228	-	-	-	-
12	2016	368	368	368	368	368	368	368	368	368	368	368	368	-	-
13	2017	245	245	245	245	245	245	245	245	245	245	245	245	245	245
14	2017	137	137	137	137	137	137	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 20
RPS Energy Position by Vintage (GWh)

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2004-2009	871	871	871	871	871	871	871	871	-	-	-	-	-	-
2010	114	114	114	114	114	114	114	114	114	-	-	-	-	-
2011	736	736	736	736	736	736	736	736	736	736	736	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	368	368	368	368	368	368	368	368	368	368	368	368	368	368
2015	228	228	228	228	228	228	228	228	228	228	-	-	-	-
2016	368	368	368	368	368	368	368	368	368	368	368	368	-	-
2017	382	382	382	382	382	382	245	245	245	245	245	245	245	245
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 21

RPS Energy Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	115	115	115	115	115	115	115	115	-	-	-	-	-	-
B	90	90	90	90	90	90	90	90	55	50	50	17	17	17
C	45	45	45	45	45	45	43	43	32	30	26	15	9	9
D	545	545	545	545	545	545	519	519	382	361	317	184	114	114
Total	3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 22
RPS Energy Long-Term Allocations Accepted (GWh)

LSE	Allocation Election (Long-Term)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	100%	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C	70%	32	32	32	32	32	32	30	30	22	21	19	11	7	7
D	50%	273	273	273	273	273	273	260	260	191	180	159	92	57	57
Total		2,576	2,576	2,576	2,576	2,576	2,576	2,453	2,453	1,803	1,705	1,500	868	537	537

Table 23
RPS Energy Short-Term Allocations Accepted (GWh)

LSE	Allocation Election (Short-Term)	2023
IOU	0%	-
A	0%	-
B	0%	-
C	30%	14
D	0%	-
Total		14

Table 24
Total RPS Energy Allocations Accepted (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C	45	32	32	32	32	32	30	30	22	21	19	11	7	7
D	273	273	273	273	273	273	260	260	191	180	159	92	57	57
Total	2,589	2,576	2,576	2,576	2,576	2,576	2,453	2,453	1,803	1,705	1,500	868	537	537

Table 25
2023 RPS Allocation Payments

LSE	2023 RPS Allocation Payment ($)
IOU	$ 40,881,567
A	$ -
B	$ -
C	$ 817,631
D	$ 4,905,788
Total	$ 46,604,986

Table 26
Distribution of 2023 RPS Allocation Payments Across Vintages ($)

Vintage	2023 RPS Allocation Payment ($)
CTC-Eligible	$ -
2004-2009	$ 11,755,044.00
2010	$ 1,770,316.36
2011	$ 11,438,967.27
2012	$ -
2013	$ -
2014	$ 5,719,483.64
2015	$ 3,709,234.29
2016	$ 5,991,840.00
2017	$ 6,220,100.57
2018	$ -
2019	$ -
2020	$ -
Total	$ 46,604,986

Table 27

RPS Allocations Declined (GWh)

LSE	2023
IOU	-
A	115
B	90
C	-
D	273
Total	477

Table 28

RPS Energy Available for Long-Term Market Offer (GWh)

Long-Term RPS Sales Cap	35%

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A	40	40	40	40	40	40	40	40	-	-	-	-	-	-
B	31	31	31	31	31	31	31	31	19	18	18	6	6	6
C	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	95	95	95	95	95	95	95	95	95	95	95	64	40	40
Max Long-Term for Market Offer	167	167	167	167	167	167	167	167	115	113	113	70	46	46
Total for Market Offer	477													

Table 29
2023 RPS Market Offer Bids and Selections

Bid #	% of Generation	Price ($/MWh)	Term (Years)	Volume (GWh)	Long-Term Volume (GWh)	Cumulative Long-Term Volume (GWh)	Total Cumulative Volume (GWh)	Bid Selection	Volume Sold (GWh)	% Sold	Term	2023 Revenues ($)
1	20%	$22	1	95	0	0	95	Selected	95	20%	Short-Term	$2,098,070
2	30%	$17	1	143	0	0	238	Selected	143	30%	Short-Term	$2,431,854
3	20%	$16	10	33	33	33	272	Selected	33	20%	Long-Term	$534,054
4	10%	$15	1	48	0	33	319	Selected	48	10%	Short-Term	$715,251
5	25%	$14	1	119	0	33	439	Selected	119	25%	Short-Term	$1,668,919
6	5%	$12	12	8	8	42	447	Partially Selected	8	5%	Long-Term	$100,135
7	40%	$9	1	191	0	42	477	Partially Selected	30	6%	Short-Term	$268,219
8	20%	$8	10	33	33	75	477	Not Selected	0	0%	Long-Term	$0
9	100%	$2	14	167	167	167	477	Not Selected	0	0%	Long-Term	$0
10	100%	$1	1	477	0	167	477	Not Selected	0	0%	Short-Term	$0
Total								Total GWh	477		Total Revenues	$7,816,503
								Short-Term	435	91%	Weighted Avg Price	$16.39
								Long-Term	42	25%		

Table 30

2023 RPS Market Offer Revenue Allocation by Vintage

Vintage	2023 Declined RPS Volumes (GWh)	2023 Revenues ($)
CTC-Eligible	0	$0
2004-2009	218	$3,568,418
2010	16	$254,561
2011	100	$1,644,853
2012	0	$0
2013	0	$0
2014	50	$822,427
2015	22	$355,577
2016	35	$574,393
2017	36	$596,275
2018	0	$0
2019	0	$0
2020	0	$0
Total	477	$7,816,503

Table 31

2023 RPS Market Offer Revenue Allocation by LSE

LSE	2023 Declined RPS Volumes (GWh)	2023 Revenues ($)
IOU	0	$ -
A	115	$ 1,878,115
B	90	$ 1,470,715
C	0	$ -
D	273	$ 4,467,674
Total	477	$ 7,816,503

Table 32

Source of Long-Term RPS Sales (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A	10	10	10	10	10	10	10	10	-	-	-	-	-	-
B	8	8	8	8	8	8	8	8	5	4	4	1	1	1
C	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	24	24	24	24	24	24	24	24	24	24	24	16	10	10
Total	42	42	42	42	42	42	42	42	29	28	28	18	11	11

Table 33

RPS Energy Available for IRP CNS Credit (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	-	105	105	105	105	105	105	105	-	-	-	-	-	-
B	-	82	82	82	82	82	82	82	51	46	46	15	15	15
C	45	45	45	45	45	45	43	43	32	30	26	15	9	9
D	273	521	521	521	521	521	495	495	358	337	294	168	104	104
Total	2,589	3,024	3,024	3,024	3,024	3,024	2,888	2,888	2,030	1,916	1,689	964	602	602

Table 34

Monthly Effective Load Carrying Capacity (ELCC)

	Month											
Technology	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Solar	4%	3%	18%	15%	16%	31%	39%	27%	14%	2%	2%	0%
Wind	14%	12%	28%	25%	25%	33%	23%	21%	15%	8%	12%	13%
Geothermal	95%	92%	88%	76%	74%	70%	84%	82%	83%	86%	93%	95%
Biomass	82%	86%	84%	76%	83%	89%	87%	90%	90%	81%	85%	86%
Small Hydro	60%	70%	73%	72%	69%	74%	73%	72%	71%	64%	56%	64%
Large Hydro	60%	70%	73%	72%	69%	74%	73%	72%	71%	64%	56%	64%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Gas CCGT	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Gas Peaker	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 35
Monthly Contract NQC Value (MW)

		Month											
Contract #	**Technology**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	Large Hydro	120	140	146	144	138	148	146	144	142	128	112	128
2	Large Hydro	30	35	37	36	35	37	37	36	36	32	28	32
3	Nuclear	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	Gas CCGT	800	800	800	800	800	800	800	800	800	800	800	800
5	Gas Peaker	50	50	50	50	50	50	50	50	50	50	50	50
6	Wind	13	11	25	23	23	30	21	19	14	7	11	12
7	Geothermal	95	92	88	76	74	70	84	82	83	86	93	95
8	Wind	7	6	14	13	13	17	12	11	8	4	6	7
9	Solar	12	9	54	45	48	93	117	81	42	6	6	-
10	Solar	6	5	27	23	24	47	59	41	21	3	3	-
11	Wind	14	12	28	25	25	33	23	21	15	8	12	13
12	Solar	6	5	27	23	24	47	59	41	21	3	3	-
13	Solar	4	3	18	15	16	31	39	27	14	2	2	-
14	Wind	8	7	17	15	15	20	14	13	9	5	7	8
15	Gas Peaker	50	50	50	50	50	50	50	50	50	50	50	50
16	Gas CCGT	800	800	800	800	800	800	800	800	800	800	800	800
17	Gas CCGT	500	500	500	500	500	500	500	500	500	500	500	500
18	Gas CCGT	300	300	300	300	300	300	300	300	300	300	300	300
19	Gas Peaker	100	100	100	100	100	100	100	100	100	100	100	100
	Total	3,915	3,924	4,081	4,036	4,034	4,171	4,209	4,114	4,004	3,884	3,883	3,894

Table 36

Local RA Position by Contract (MW)

		Month											
Contract	**Vintage**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	50	50	50	50	50	50	50	50	50	50	50	50
16	2018	800	800	800	800	800	800	800	800	800	800	800	800
17	2020	500	500	500	500	500	500	500	500	500	500	500	500
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

		Month (continued)											
Contract	**Vintage**	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	800	800	800	800	800	800	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

		Month (continued)											
Contract	**Vintage**	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 37

Local RA Position by Vintage (MW)

Vintage	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	50	50	50	50	50	50	50	50	50	50	50	50
2018	800	800	800	800	800	800	800	800	800	800	800	800
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	500	500	500	500	500	500	500	500	500	500	500	500
Total	3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

Month (continued)

Vintage	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	800	800	800	800	800	800	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

Month (continued)

Vintage	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 38
Local RA Allocations (MW)

	Month											
LSE	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
IOU	2,432	2,445	2,449	2,447	2,444	2,450	2,449	2,447	2,446	2,437	2,427	2,437
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	45	45	45	45	45	45	45	45	45	45	44	45
D	520	524	525	524	523	525	525	524	524	522	519	522
Total	3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

	Month (continued)											
LSE	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
IOU	1,893	1,906	1,910	1,909	1,905	1,911	1,291	1,290	1,288	1,279	1,269	1,279
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	44	44	44	44	44	44	30	30	30	30	29	30
D	510	513	514	514	513	515	348	347	347	344	342	344
Total	2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

	Month (continued)											
LSE	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
IOU	1,274	1,287	1,291	1,290	1,286	1,292	1,291	1,290	1,288	1,279	1,269	1,279
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	29	30	30	30	30	30	30	30	30	30	29	30
D	343	347	348	347	346	348	348	347	347	344	342	344
Total	1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 39
System RA Position by Contract (MW)

		Month											
Contract	**Vintage**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	300	300	300	300	-	-
19	2020	-	-	100	100	100	100	100	100	-	-	-	-
Total		195	184	435	392	396	523	863	770	562	456	171	166

		Month (continued)											
Contract	**Vintage**	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		195	184	335	292	296	423	463	370	262	156	171	166

		Month (continued)											
Contract	**Vintage**	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		195	184	335	292	296	423	463	370	262	156	171	166

Table 40
System RA Position by Vintage (MW)

	Month											
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	100	100	100	100	400	400	300	300	-	-
Total	195	184	435	392	396	523	863	770	562	456	171	166

	Month (continued)											
Vintage	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	195	184	335	292	296	423	463	370	262	156	171	166

	Month (continued)											
Vintage	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	195	184	335	292	296	423	463	370	262	156	171	166

Table 41

System RA Allocation Eligibility (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	133	124	336	306	309	404	733	664	483	404	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	435	392	396	523	863	770	562	456	171	166

	Month (continued)											
LSE	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
IOU	133	124	236	206	209	304	333	264	183	104	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	335	292	296	423	463	370	262	156	171	166

	Month (continued)											
LSE	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
IOU	133	124	236	206	209	304	333	264	183	104	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	335	292	296	423	463	370	262	156	171	166

Table 42

2023 System RA Allocations Accepted (MW)

		Month											
LSE	**Allocation Election %**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	100%	133	124	336	306	309	404	733	664	483	404	115	111
A	0%	-	-	-	-	-	-	-	-	-	-	-	-
B	50%	3	3	5	4	5	6	7	6	4	3	3	3
C	0%	-	-	-	-	-	-	-	-	-	-	-	-
D	80%	29	27	51	44	45	66	72	57	39	22	25	24
Available for Market Offer (MW)		31	30	42	37	37	47	50	43	35	26	28	29
Total (MW)		195	184	435	392	396	523	863	770	562	456	171	166

Table 43

2023 System RA Allocation Payments by LSE ($)

	Month												
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
IOU	$596,396	$558,848	$1,514,158	$1,377,230	$1,390,707	$1,820,104	$3,300,170	$2,989,235	$2,173,958	$1,819,580	$ 517,723	$ 497,713	$18,555,821
A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
B	$ 14,879	$ 14,335	$ 23,122	$ 20,227	$ 20,373	$ 28,196	$ 31,770	$ 25,760	$ 19,031	$ 12,541	$ 13,337	$ 13,086	$ 236,657
C	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
D	$128,454	$120,367	$ 229,203	$ 199,711	$ 202,614	$ 295,099	$ 323,113	$ 256,143	$ 177,468	$ 101,140	$ 111,510	$ 107,200	$ 2,252,023
Total	$739,729	$693,550	$1,766,483	$1,597,168	$1,613,694	$2,143,400	$3,655,053	$3,271,138	$2,370,457	$1,933,262	$ 642,569	$ 617,998	$21,044,501

Table 44

Distribution of 2023 System RA Allocation Payments Across Vintages ($)

	Month												
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
CTC-Eligible	$108,806	$126,940	$ 132,381	$ 130,567	$ 125,127	$ 134,194	$ 132,381	$ 130,567	$ 128,754	$ 116,060	$ 101,552	$ 116,060	$ 1,483,388
2004-2009	$390,251	$372,842	$ 410,561	$ 357,246	$ 349,993	$ 361,599	$ 379,733	$ 365,951	$ 349,993	$ 338,024	$ 376,469	$ 386,987	$ 4,439,646
2010	$ 28,994	$ 24,852	$ 57,989	$ 51,776	$ 51,776	$ 68,344	$ 47,634	$ 43,491	$ 31,065	$ 16,568	$ 24,852	$ 26,923	$ 474,264
2011	$ 49,705	$ 37,278	$ 223,670	$ 186,392	$ 198,818	$ 385,210	$ 484,619	$ 335,506	$ 173,966	$ 24,852	$ 24,852	$ -	$ 2,124,869
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 24,852	$ 18,639	$ 111,835	$ 93,196	$ 99,409	$ 192,605	$ 242,310	$ 167,753	$ 86,983	$ 12,426	$ 12,426	$ -	$ 1,062,435
2015	$ 59,250	$ 50,786	$ 118,500	$ 105,804	$ 105,804	$ 139,661	$ 97,339	$ 88,875	$ 63,482	$ 33,857	$ 50,786	$ 55,018	$ 969,161
2016	$ 25,393	$ 19,045	$ 114,268	$ 95,223	$ 101,571	$ 196,795	$ 247,580	$ 171,402	$ 88,875	$ 12,696	$ 12,696	$ -	$ 1,085,545
2017	$ 52,479	$ 43,168	$ 147,279	$ 126,964	$ 131,196	$ 214,993	$ 223,457	$ 167,593	$ 97,339	$ 28,779	$ 38,936	$ 33,011	$ 1,305,193
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$1,800,000	$1,800,000	$1,350,000	$1,350,000	$ -	$ -	$ 8,100,000
Total	$739,729	$693,550	$1,766,483	$1,597,168	$1,613,694	$2,143,400	$3,655,053	$3,271,138	$2,370,457	$1,933,262	$ 642,569	$ 617,998	$21,044,501

Table 45

2023 Declined System RA (MW)

		Month												
LSE	**Allocation Election %**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
IOU	100%	-	-	-	-	-	-	-	-	-	-	-	-	-
A	0%	17	17	19	17	16	17	18	17	16	16	16	17	203
B	50%	3	3	5	4	5	6	7	6	4	3	3	3	53
C	0%	3	3	5	5	5	7	8	6	4	2	3	3	54
D	80%	7	7	13	11	11	16	18	14	10	6	6	6	125
Total		31	30	42	37	37	47	50	43	35	26	28	29	434

Table 46
2023 System RA Market Offer Bids

			Offer Term													
Bid #	**Volume (MW)**	**Price ($/kW-mo)**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Revenue ($)**	**Selected**
1	5	$6.00	0	0	0	0	0	0	0	0	1	0	0	0	$0	0
2	10	$5.50	0	0	0	0	0	1	1	1	0	0	0	0	$165,000	1
3	49	$1.50	1	1	1	1	1	1	1	1	1	1	1	1	$0	0
4	20	$2.50	1	1	1	1	1	1	1	1	1	1	1	1	$0	0
5	25	$4.25	0	0	0	1	1	1	1	1	1	0	0	0	$0	0
6	10	$5.25	0	0	0	0	0	0	1	1	1	0	0	0	$157,500	1
7	2	$5.75	0	0	0	1	1	1	1	1	1	0	0	0	$69,000	1
8	5	$3.50	0	0	0	1	1	1	1	1	1	1	1	1	$157,500	1
9	30	$4.00	0	0	0	0	0	0	1	1	0	0	0	0	$0	0
10	15	$2.75	1	1	1	1	1	1	1	1	1	1	1	1	$495,000	1
														Total Revenues ($)	$1,044,000	
														Weighted Average Sales Price ($/kW-mo)	$3.52	
														Weighted Average Price (Sold & Unsold) ($/kW-mo)	$2.40	

Table 47
2023 System RA Volumes Sold in Market Offer (MW)

	Monthly Volumes Selected												
Offer #	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	10	10	10	0	0	0	0	30
3	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	10	10	10	0	0	0	30
7	0	0	0	2	2	2	2	2	2	0	0	0	12
8	0	0	0	5	5	5	5	5	5	5	5	5	45
9	0	0	0	0	0	0	0	0	0	0	0	0	0
10	15	15	15	15	15	15	15	15	15	15	15	15	180
Total	15	15	15	22	22	32	42	42	32	20	20	20	297

Table 48

2023 Unsold System RA (MW)

	Month												
	1/1/2023	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
Unsold System RA (MW)	16	15	27	15	15	15	8	1	3	6	8	9	137
												Total RA (Sold and Unsold)	434

Table 49

2023 Unsold System RA by Vintage (MW)

	Month											
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
CTC-Eligible	3.0	3.4	4.5	2.8	2.7	2.3	1.2	0.2	0.5	1.5	1.6	1.9
2004-2009	10.6	9.9	14.1	7.8	7.6	6.1	3.3	0.5	1.5	4.4	5.9	6.3
2010	0.3	0.2	0.7	0.4	0.4	0.4	0.2	0.0	0.0	0.1	0.1	0.2
2011	0.5	0.4	2.8	1.5	1.5	2.3	1.5	0.2	0.3	0.1	0.1	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	0.2	0.2	1.4	0.7	0.8	1.2	0.8	0.1	0.1	0.1	0.1	-
2015	0.4	0.4	1.1	0.6	0.6	0.6	0.2	0.0	0.1	0.1	0.2	0.2
2016	0.2	0.1	1.0	0.5	0.6	0.9	0.6	0.1	0.1	0.0	0.1	-
2017	0.4	0.3	1.3	0.7	0.7	1.0	0.5	0.1	0.1	0.1	0.2	0.1
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	16	15	27	15	15	15	8	1	3	6	8	9

Table 50

2023 Unsold System RA Re-Allocations (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	10.3	9.8	18.3	10.2	10.1	10.2	5.7	0.7	1.8	4.2	5.4	5.7
A	1.7	1.7	2.3	1.3	1.3	1.0	0.6	0.1	0.3	0.7	0.9	1.0
B	0.6	0.6	1.0	0.5	0.5	0.5	0.3	0.0	0.1	0.2	0.3	0.3
C	0.2	0.2	0.4	0.2	0.2	0.2	0.1	0.0	0.0	0.1	0.1	0.1
D	2.8	2.6	4.9	2.8	2.7	2.7	1.5	0.2	0.5	1.1	1.5	1.5
Total	16	15	27	15	15	15	8	1	3	6	8	9

Table 51

2023 Total System RA Allocations (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	143	134	355	316	319	415	739	665	485	409	120	116
A	2	2	2	1	1	1	1	0	0	1	1	1
B	4	4	6	5	5	7	7	6	4	3	3	3
C	0	0	0	0	0	0	0	0	0	0	0	0
D	31	29	56	47	48	68	73	57	40	24	26	25
Total Allocated	180	169	420	370	374	491	821	728	530	436	151	146
Total Sold	15	15	15	22	22	32	42	42	32	20	20	20
Total RA	195	184	435	392	396	523	863	770	562	456	171	166

Table 52

2023 Market Offer Revenue Allocation across Vintages ($)

	Month												
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
CTC-Eligible	$ 13,988	$ 16,319	$ 17,019	$ 16,786	$ 16,086	$ 17,252	$ 17,019	$ 16,786	$ 16,552	$ 14,921	$ 13,055	$ 14,921	$ 190,703
2004-2009	$ 50,170	$ 47,932	$ 52,781	$ 45,927	$ 44,995	$ 46,487	$ 48,818	$ 47,046	$ 44,995	$ 43,456	$ 48,399	$ 49,751	$ 570,758
2010	$ 1,338	$ 1,147	$ 2,676	$ 2,389	$ 2,389	$ 3,154	$ 2,198	$ 2,007	$ 1,434	$ 765	$ 1,147	$ 1,242	$ 21,887
2011	$ 2,294	$ 1,720	$ 10,322	$ 8,602	$ 9,175	$ 17,777	$ 22,365	$ 15,483	$ 8,028	$ 1,147	$ 1,147	$ -	$ 98,062
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 1,147	$ 860	$ 5,161	$ 4,301	$ 4,588	$ 8,889	$ 11,182	$ 7,742	$ 4,014	$ 573	$ 573	$ -	$ 49,031
2015	$ 2,003	$ 1,716	$ 4,005	$ 3,576	$ 3,576	$ 4,720	$ 3,290	$ 3,004	$ 2,146	$ 1,144	$ 1,716	$ 1,860	$ 32,756
2016	$ 858	$ 644	$ 3,862	$ 3,218	$ 3,433	$ 6,651	$ 8,368	$ 5,793	$ 3,004	$ 429	$ 429	$ -	$ 36,690
2017	$ 1,774	$ 1,459	$ 4,978	$ 4,291	$ 4,434	$ 7,266	$ 7,553	$ 5,664	$ 3,290	$ 973	$ 1,316	$ 1,116	$ 44,113
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 73,572	$ 71,798	$100,805	$ 89,091	$ 88,677	$112,197	$120,793	$103,526	$ 83,463	$ 63,408	$ 67,783	$ 68,889	$1,044,000

Table 53

2023 Market Offer Revenue Allocation by LSE

LSE	**Declined System RA Volumes (MW)**	**2022 Revenues**
IOU	0	$ -
A	203	$ 488,116
B	53	$ 126,378
C	54	$ 128,852
D	125	$ 300,654
Total	434	$ 1,044,000

Table 54

2023 Market Price Benchmark Assumptions

MPBs	Local RA	System RA	Flex RA	RPS	Energy
2023	$5.50	$4.50	$3.50	$18.00	$22.00

Table 55

2023 Costs and Energy Revenues by Contract

Contract	Vintage	Contract Cost	Energy Value	Net Above Market Cost
1	CTC-Eligible	$ 14,716,800	$ (16,188,480)	$ (1,471,680)
2	CTC-Eligible	$ 4,599,000	$ (4,047,120)	$ 551,880
3	CTC-Eligible	$257,894,400	$(177,302,400)	$ 80,592,000
4	CTC-Eligible	$134,904,000	$ (84,796,800)	$ 50,107,200
5	2004-2009	$ 2,365,200	$ (1,156,320)	$ 1,208,880
6	2004-2009	$ 51,246,000	$ (4,509,648)	$ 46,736,352
7	2004-2009	$ 79,891,200	$ (14,646,720)	$ 65,244,480
8	2010	$ 22,776,000	$ (2,505,360)	$ 20,270,640
9	2011	$183,960,000	$ (16,188,480)	$167,771,520
10	2014	$ 66,225,600	$ (8,094,240)	$ 58,131,360
11	2015	$ 31,886,400	$ (5,010,720)	$ 26,875,680
12	2016	$ 18,396,000	$ (8,094,240)	$ 10,301,760
13	2017	$ 11,037,600	$ (5,396,160)	$ 5,641,440
14	2017	$ 5,739,552	$ (3,006,432)	$ 2,733,120
15	2017	$ 2,700,000	$ -	$ 2,700,000
16	2018	$ 48,000,000	$ -	$ 48,000,000
17	2020	$ 20,400,000	$ -	$ 20,400,000
18	2020	$ 4,950,000	$ -	$ 4,950,000
19	2020	$ 1,800,000	$ -	$ 1,800,000
Total		$963,487,752	$(350,943,120)	$612,544,632

Table 56

2023 Net Above Market Costs to be Recovered in PCIA Rates by Vintage ($)

Vintage	Contract Cost	Energy Value	Net Above Market Cost (Ratemaking Option 1)	RA Allocation Revenue	RA Market Offer Revenue	RPS Allocation Revenue	RPS Market Offer Revenue	Net Above Market Cost (Ratemaking Option 2)
CTC-Eligible	$ 412,114,200	$ (282,334,800)	$ 129,779,400	$ (1,483,388)	$ (190,703)	$ -	$ -	$ 128,105,309
2004-2009	$ 133,502,400	$ (20,312,688)	$ 113,189,712	$ (4,439,646)	$ (570,758)	$ (11,755,044)	$ (3,568,418)	$ 92,855,846
2010	$ 22,776,000	$ (2,505,360)	$ 20,270,640	$ (474,264)	$ (21,887)	$ (1,770,316)	$ (254,561)	$ 17,749,612
2011	$ 183,960,000	$ (16,188,480)	$ 167,771,520	$ (2,124,869)	$ (98,062)	$ (11,438,967)	$ (1,644,853)	$ 152,464,769
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2014	$ 66,225,600	$ (8,094,240)	$ 58,131,360	$ (1,062,435)	$ (49,031)	$ (5,719,484)	$ (822,427)	$ 50,477,984
2015	$ 31,886,400	$ (5,010,720)	$ 26,875,680	$ (969,161)	$ (32,756)	$ (3,709,234)	$ (355,577)	$ 21,808,952
2016	$ 18,396,000	$ (8,094,240)	$ 10,301,760	$ (1,085,545)	$ (36,690)	$ (5,991,840)	$ (574,393)	$ 2,613,292
2017	$ 19,477,152	$ (8,402,592)	$ 11,074,560	$ (1,305,193)	$ (44,113)	$ (6,220,101)	$ (596,275)	$ 2,908,878
2018	$ 48,000,000	$ -	$ 48,000,000	$ -	$ -	$ -	$ -	$ 48,000,000
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2020	$ 27,150,000	$ -	$ 27,150,000	$ (8,100,000)	$ -	$ -	$ -	$ 19,050,000
Total	$ 963,487,752	$ (350,943,120)	$ 612,544,632	$ (21,044,501)	$ (1,044,000)	$ (46,604,986)	$ (7,816,503)	$ 536,034,642

Table 57

2023 Illustrative PCIA Rate Calculations

Vintage	Net Above Market Cost (Ratemaking Option 1)	Net Above Market Cost (Ratemaking Option 2	Load (GWh)	Incremental Rate ($/kWh) (Ratemaking Option 1)	Incremental Rate ($/kWh) (Ratemaking Option 2)	Rate ($/kWh) (Ratemaking Option 1)	Rate ($/kWh) (Ratemaking Option 2)
CTC-Eligible	$ 129,779,400	$ 128,105,309	76,000	$ 0.001708	$ 0.001686	$ 0.001708	$ 0.001686
2004-2009	$ 113,189,712	$ 92,855,846	76,000	$ 0.001489	$ 0.001222	$ 0.003197	$ 0.002907
2010	$ 20,270,640	$ 17,749,612	66,000	$ 0.000307	$ 0.000269	$ 0.003504	$ 0.003176
2011	$ 167,771,520	$ 152,464,769	66,000	$ 0.002542	$ 0.002310	$ 0.006046	$ 0.005486
2012	$ -	$ -	66,000	$ -	$ -	$ 0.006046	$ 0.005486
2013	$ -	$ -	66,000	$ -	$ -	$ 0.006046	$ 0.005486
2014	$ 58,131,360	$ 50,477,984	66,000	$ 0.000881	$ 0.000765	$ 0.006927	$ 0.006251
2015	$ 26,875,680	$ 21,808,952	63,000	$ 0.000427	$ 0.000346	$ 0.007353	$ 0.006597
2016	$ 10,301,760	$ 2,613,292	63,000	$ 0.000164	$ 0.000041	$ 0.007517	$ 0.006639
2017	$ 11,074,560	$ 2,908,878	63,000	$ 0.000176	$ 0.000046	$ 0.007693	$ 0.006685
2018	$ 48,000,000	$ 48,000,000	63,000	$ 0.000762	$ 0.000762	$ 0.008455	$ 0.007447
2019	$ -	$ -	50,000	$ -	$ -	$ 0.008455	$ 0.007447
2020	$ 27,150,000	$ 19,050,000	50,000	$ 0.000543	$ 0.000381	$ 0.008998	$ 0.007828
Total	$ 612,544,632	$ 536,034,642					

Table 58

2023 Total Cost Responsibility - Ratemaking Option 1

LSE	Vintage	Annual Load (GWh)	Customer PCIA Rate Payments (Ratemaking Option 1)	IOU RA Revenue Payment to LSE	IOU RPS Revenue Payment to LSE	Net LSE & LSE Customer PCIA Cost Responsibility
IOU	2020	50,000	$ 449,883,667	$ -	$ -	$ 449,883,667
A	2004-2009	10,000	$ 31,969,620	$ (488,116)	$ (1,878,115)	$ 29,603,389
B	2014	3,000	$ 20,780,591	$ (126,378)	$ (1,470,715)	$ 19,183,498
C	2018	1,000	$ 8,454,673	$ (128,852)	$ -	$ 8,325,822
D	2018	12,000	$ 101,456,080	$ (300,654)	$ (4,467,674)	$ 96,687,752
			$ 612,544,632	$ (1,044,000)	$ (7,816,503)	$ 603,684,129

Table 59

2023 Total Cost Responsibility - Ratemaking Option 2

LSE	Vintage	Annual Load (GWh)	Customer PCIA Rate Payments (Ratemaking Option 2)	LSE RA Allocation Payment to IOU	LSE RPS Allocation Payment to IOU	Net LSE & LSE Customer PCIA Cost Responsibility
IOU	2020	50,000	$ 391,396,971	$ 18,555,821	$ 40,881,567	$ 450,834,359
A	2004-2009	10,000	$ 29,073,836	$ -	$ -	$ 29,073,836
B	2014	3,000	$ 18,753,622	$ 236,657	$ -	$ 18,990,279
C	2018	1,000	$ 7,446,939	$ -	$ 817,631	$ 8,264,571
D	2018	12,000	$ 89,363,273	$ 2,252,023	$ 4,905,788	$ 96,521,084
			$ 536,034,642	$ 21,044,501	$ 46,604,986	$ 603,684,129

Appendix I

RPS LONG-TERM ALLOCATION EXAMPLES

Example of Long-Term vs. Short-Term RPS Allocation Treatment

This Appendix provides a more detailed example regarding the treatment of long-term RPS energy attributes from an illustrative IOU's PCIA-eligible portfolio. This example leverages most of the same assumptions as the end-to-end example in Appendix H, but makes some minor modifications to demonstrate key aspects of long-term RPS treatment in the Co-Chairs' proposed RPS energy VAMO process. The following narrative serves as a guide to understand what takes place within each table or calculation and to provide additional context around how the results in each table are to be interpreted.

Table 1. LSE Assumptions

As with Table 1 of the end-to-end example, Table 1 in this Appendix presents the assumptions for each LSE. As this example only focuses upon the potential to accept long-term RPS allocations, only the annual load and LSE vintage is required for this example.

Table 2. LSEs' Vintaged Annual Load Shares

As in the end-to-end example, Table 2 calculates each LSE's vintaged annual (MWh) load share for this example.

Table 3. LSEs' Vintaged Annual Load Share Percentages

As in the end-to-end example, Table 3 translates Table 2 into percentages of annual vintage load.

Table 4. Model IOU RPS Portfolio

Table 4 presents this example's illustrative IOU portfolio of PCIA-eligible resources. In this example, only the RPS resources are identified. Most of the same contracts exist, but to distinguish the treatment of long-term RPS contract attribute preservation from short-term RPS contract credit, two additional short-term RPS contracts (*i.e.*, with less than 10 years in their original contract term) have been added. These contracts are identified as Contracts 6 and 9. Additionally, some of the term start dates have been updated.

Table 5. <u>Contract-Specific Long-Term RPS Energy Production Forecast</u>

The Co-Chairs propose that for an LSE to receive long-term RPS credit through an allocation, the underlying IOU contracts must have originally been long-term contracts. Thus, Table 5 calculates how much RPS energy is available in each delivery year only for the contracts that qualify as long-term contracts. Thus, Contracts 6 and 9 have no long-term RPS energy production in this table. The contracts' vintages are identified so that the forecasted long-term RPS generation can be summed by vintage in Table 6.

Table 6. <u>Vintage-Specific Long-Term RPS Energy Production</u>

Table 6 sums the long-term RPS energy available in each delivery year by vintage. This will be used in Table 7 to determine each LSE's eligible share of the PCIA-eligible RPS portfolio on the basis of their customers' departure date.

By reviewing this illustrative data for the 2004-2009 vintage, it can be seen that LSEs in that vintage would not be able to receive RPS allocations for a full 10 years, as the longest dated contract (Contract 2 from Tables 4 and 5) would cease deliveries in 2031 (the 9th year of allocations from a January 1, 2023 implementation date). Similarly, if a 2010-vintaged LSE wished to take an allocation, their allocation would not fulfill a complete 10 years, as the longest dated contract (Contract 3) would expire on February 29, 2032, resulting in an allocation term of 9 years and 2 months. Ultimately, however, it is most complete to review the actual volumes that each LSE would be eligible to receive from the long-term PCIA-eligible RPS energy portfolio, as demonstrated in Table 7.

Table 7. <u>Long-Term RPS Energy Allocation Eligibility</u>

Table 7 illustrates the allocation volumes that each of the illustrative LSEs would be eligible to receive of the IOU's PCIA-eligible, long-term RPS energy. This table is calculated in the same manner as Table 21 in the end-to-end example from Appendix H.

It is helpful to review this table to determine the ability of an LSE to get long-term RPS credit, rather than Table 6, as later-vintaged LSEs will be eligible to receive allocations sourced from earlier-vintaged contracts. Here it is again clear that a 2004-2009 vintaged LSE (LSE A in this example) would not be eligible for an allocation that spans 10 years in length. Similarly, a 2010-vintaged LSE (LSE B) would not get a full 10 year allocation term. LSEs may find themselves in this situation as a result of the date upon which the RPS VAMO proposal is implemented. These LSEs still pay the same PCIA rates associated with the vintages they are eligible to take as an allocation as later-vintaged LSEs, but would not be able to claim long-term RPS credit by taking a long-term allocation.

Thus, the Co-Chairs have proposed that in the first RPS allocation election opportunity, LSEs that would not be able to take a 10-year allocation should be grandfathered into the long-term treatment of the IOU's underlying contracts. This would allow LSE A and B in this example to receive all of the forecasted energy production identified in Table 7 as long-term RPS energy, rather than solely as short-term RPS energy.

Outside of the single grandfathering opportunity, LSEs may only receive long-term credit if they elect their long-term allocation when the remaining term of the longest dated, non-evergreen and non-UOG, contract has at least 10 or more years remaining in its contract term. Thus, LSE C may, in each annual election opportunity, elect to accept a short-term allocation or to decline its allocations, in each case electing to not receive long-term RPS procurement credit for such delivery years, but still preserve its ability to enter into a long-term allocation as long as it makes a long-term election by the 2026 elections for 2027-2037 delivery term for LSE C. For clarity, in this case, LSE C would only receive long-term RPS credit for 2027-2037 and would have foregone long-term credit prior to such delivery years. LSE D would be in a similar situation and could make a long-term election as late as 2028 for the 2029-2039 delivery years to receive long-term credit for that specific allocation term.

Table 1

LSE Assumptions

LSE	Vintage	Annual Load (GWh)
IOU	2020	50,000
A	2004-2009	10,000
B	2010	3,000
C	2014	1,000
D	2018	12,000

Table 2

LSE's Vintaged Annual Load Shares

		Annual Vintaged Loads (GWh)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
A	2004-2009	10,000	10,000	-	-	-	-	-	-	-	-	-	-	-
B	2010	3,000	3,000	3,000	-	-	-	-	-	-	-	-	-	-
C	2014	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-	-	-	-	-	-
D	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	-	-
Total		76,000	76,000	66,000	63,000	63,000	63,000	63,000	62,000	62,000	62,000	62,000	50,000	50,000

Table 3

LSE's Vintaged Annual Load Share Percentages

		Annual Vintaged Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	66%	66%	76%	79%	79%	79%	79%	81%	81%	81%	81%	100%	100%
A	2004-2009	13%	13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2010	4%	4%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
C	2014	1%	1%	2%	2%	2%	2%	2%	0%	0%	0%	0%	0%	0%
D	2018	16%	16%	18%	19%	19%	19%	19%	19%	19%	19%	19%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 4
Model IOU RPS Portfolio

Contract #	Vintage	Online Date	Term (Years)	Termination Date	Technology	Installed AC Capacity (MW)	Expected Annual Energy Production (GWh)
1	2004-2009	1/1/2011	20	12/31/2030	Wind	90	205
2	2004-2009	7/1/2011	20	6/30/2031	Geothermal	100	666
3	2010	3/1/2012	20	2/29/2032	Wind	50	114
4	2011	1/1/2014	20	12/31/2033	Solar	300	736
5	2014	1/1/2018	20	12/31/2037	Solar	150	368
6	2014	3/1/2019	5	2/28/2024	Wind	120	273
7	2015	7/1/2018	15	6/30/2033	Wind	100	228
8	2016	1/1/2020	15	12/31/2034	Solar	150	368
9	2016	9/1/2018	8	8/31/2026	Solar	90	221
10	2017	1/1/2020	20	12/31/2039	Solar	100	245
11	2017	1/1/2019	10	12/31/2028	Wind	60	137

Table 5

Contract-Specific Long-Term RPS Energy Production Forecast (GWh)

Contract #	Vintage	Term (Years)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	2004-2009	20	205	205	205	205	205	205	205	205	0	0	0	0	0	0	0	0	0	0
2	2004-2009	20	666	666	666	666	666	666	666	666	333	0	0	0	0	0	0	0	0	0
3	2010	20	114	114	114	114	114	114	114	114	114	19	0	0	0	0	0	0	0	0
4	2011	20	736	736	736	736	736	736	736	736	736	736	736	0	0	0	0	0	0	0
5	2014	20	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0
6	2014	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	2015	15	228	228	228	228	228	228	228	228	228	228	114	0	0	0	0	0	0	0
8	2016	15	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0	0	0	0
9	2016	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2017	20	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	0
11	2017	10	137	137	137	137	137	137	0	0	0	0	0	0	0	0	0	0	0	0
Total			3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Table 6

Vintage-Specific Long-Term RPS Energy Production (GWh)

Vintage	Allocation Year / Delivery Year	1 2023	2 2024	3 2025	4 2026	5 2027	6 2028	7 2029	8 2030	9 2031	10 2032	11 2033	12 2034	13 2035	14 2036	15 2037	16 2038	17 2039	18 2040
CTC-Eligible		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-2009		871	871	871	871	871	871	871	871	333	0	0	0	0	0	0	0	0	0
2010		114	114	114	114	114	114	114	114	114	19	0	0	0	0	0	0	0	0
2011		736	736	736	736	736	736	736	736	736	736	736	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014		368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0
2015		228	228	228	228	228	228	228	228	228	228	114	0	0	0	0	0	0	0
2016		368	368	368	368	368	368	368	368	368	368	368	368	0	0	0	0	0	0
2017		382	382	382	382	382	382	245	245	245	245	245	245	245	245	245	245	245	0
2018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Table 7

Long-Term RPS Energy Allocation Eligibility (GWh)

	Allocation Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
LSE	**Vintage**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
IOU	2020	2,324	2,324	2,324	2,324	2,324	2,324	2,213	2,213	1,859	1,568	1,462	787	490	490	490	198	198	-
A	2004-2009	115	115	115	115	115	115	115	115	44	-	-	-	-	-	-	-	-	-
B	2010	40	40	40	40	40	40	40	40	18	1	-	-	-	-	-	-	-	-
C	2014	31	31	31	31	31	31	31	31	24	18	18	6	6	6	6	-	-	-
D	2018	558	558	558	558	558	558	531	531	446	376	351	189	118	118	118	47	47	-
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Appendix J

PROPOSED IMPLEMENTATION TIMELINES

Legend
BPP
ERRA
GHG-Free Term Sheet & Advice Letter
IOU Procurement / Sales Activity
IRP
PCIA OIR
RA OIR
RA Process
RPS OIR

Indicative GHG-Free Energy Voluntary Allocation Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Delivery Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
GHG-Free Term Sheet & Advice Letter	SCE to file Interim GHG-Free Allocation Term Sheet & Advice Letter for Approval	Within 30 days of filing Final Report	3/22/2020	2020-2022	Request approval for interim GHG-free energy voluntary allocation approach on basis of actual load shares
PCIA OIR	Reply Comments		3/27/2020	All	
GHG-Free Term Sheet & Advice Letter	Receive Approval for GHG-free energy voluntary allocations	3 months after filing Advice Letter	6/20/2020	2020-2022	Enable interim GHG-free energy voluntary allocation approach
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections, pending approval of Advice Letter	Approval of Advice Letter + 30 days	8/19/2020	2020	LSEs submit allocation elections, to permit rapid implementation of allocations
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2020	Next month after LSEs submit elections	9/1/2020	2020	Commence scheduling energy for allocations
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections for 2021	November 2020	11/15/2020	2021	LSEs submit allocation elections for 2021
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2023	Introduce discussion of vintaged annual load forecasting methodologies into RA OIR Scoping Memo
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2023	Request approval to conduct WG 3's proposed voluntary allocations
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2021	January 1, 2021	1/1/2021	2021	Commence scheduling energy for allocations
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2023	Receive approval to conduct WG 3's proposed voluntary allocations
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2022	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2023	Rule upon vintaged annual load forecasting methodologies
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections for 2022	November 2021	11/15/2021	2022	LSEs submit allocation elections for 2022
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2022	Publish forecasted volumes and vintaged annual loads for 2022.
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2022	January 1, 2022	1/1/2022	2022	Commence scheduling energy for allocations

IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, annual load shares for allocation of Clean Net Short credit
IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, annual load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast annual load shares for 2023 allocations
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations for 2023
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares
IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine allocation elections
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocation shares for 2023
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish forecasted volumes and vintaged annual loads for 2023.
IOU Procurement / Sales Activity	Commence full RPS and GHG-free energy allocations and energy scheduling for 2023	January 1, 2023	1/1/2023	2023	Commence scheduling energy for allocations
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2024	Publish forecasted volumes and vintaged annual loads for 2023.
IOU Procurement / Sales Activity	IOUs report volumes and resources sourced for RPS and GHG-free energy deliveries for Power Content Label reporting	By Q2 following delivery year	4/1/2024	2023	Facilitate Power Content Label reporting
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative RPS Energy VAMO Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Delivery Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	Approval of WG 3 Decision
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	All	Introduce discussion of advancing RA process timelines and vintaged annual load forecasting methodologies into RA OIR Scoping Memo
RPS OIR	RPS Procurement Ruling/Scoping	March/April	4/1/2021	All	Opening of OIR to update RPS Procurement Plan for VAMO implementation
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2023	Publish forecasted PCIA-eligible RPS volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	All	Rule upon updated timelines for RA process and vintaged annual load forecasting methodologies
RPS OIR	File RPS Procurement Plan	June/July	6/15/2021	All	Incorporate mechanisms and processes for VAMO for RPS energy
RPS OIR	File updates to RPS Procurement Plan	August/September	8/15/2021	All	File updates to request for approval of VAMO processes
RPS OIR	RPS Procurement Plan PD	Mid- to Late-November	11/15/2021	All	PD ruling upon proposed methodology for VAMO implementation
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2023	Publish forecasted PCIA-eligible RPS volumes
RPS OIR	Final Decision on RPS Procurement Plan	PD on RPS Procurement Plan + 30 days	12/15/2021	All	Final Decision ruling upon proposed VAMO implementation
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, annual load shares for allocation of Clean Net Short credit

IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, annual load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast annual load shares for 2023 allocations
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible RPS volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares
IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine allocation elections
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocation shares for 2023
IOU Procurement / Sales Activity	IOUs launch RPS Market Offer	Within 1 week of publication of final, forecasted, vintaged annual load shares	9/27/2022	2023	Publish RFO instructions and inform the market of estimates of RPS energy volumes for sale
IOU Procurement / Sales Activity	CAM Review of RPS Selections	Coincident with Completion of RPS Market Offer	10/18/2022	2023	Review proposed RPS Market Offer sales with CAM group
IOU Procurement / Sales Activity	Complete RPS Market Offer	3 weeks start to finish	10/18/2022	2023	Select offers and sign contracts
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish forecasted volumes, vintaged annual loads, and forecast MPB for 2023.
IOU Procurement / Sales Activity	Commence full RPS and GHG-free energy allocations and energy scheduling for 2023	January 1, 2023	1/1/2023	2023	

IOU Procurement / Sales Activity	Payment owed for allocations and sales	~20 days following close of compliance month	2/20/2023	2023	LSES accepting allocations or sales to pay for delivered RPS energy
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible RPS volumes
IOU Procurement / Sales Activity	Transfer RECs for each flow month	Within 120 days after flow month	5/31/2023	2023	Transfer RECs to parties accepting allocations or purchasing in Market Offer
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2023-24	Publish actual volumes and true-up MPB for 2023. Publish forecasted volumes, vintaged annual loads, and forecast MPB for 2024.
IOU Procurement / Sales Activity	True-Up Payment Owed for Allocations	December 2023	12/15/2023	2023	LSEs accepting allocations to pay true-up payment relating to difference between forecast and actual MPB
IOU Procurement / Sales Activity	IOUs report volumes and resources sourced for RPS and GHG-free energy deliveries for Power Content Label reporting	By Q2 following delivery year	4/1/2024	2023	Facilitate Power Content Label reporting
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative System and Flex RA VAMO Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Compliance Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2023	Introduce discussion of advancing RA process timelines; vintaged peak load forecasting methodologies; and PCIA Showing implementation
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2023	Request approval to conduct voluntary allocations and Market Offer sales
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2023	Receive approval to conduct voluntary allocations and Market Offer sales
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2023	Rule upon updated timelines for RA process; vintaged coincident peak-load forecasting methodologies; and PCIA Showing
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, coincident, peak-load shares for allocation of RA credit

IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, coincident peak-load shares
IOU Procurement / Sales Activity	LSEs submit spring RA allocation elections to IOUs	April 2022	4/1/2022	2023	Determine System/Flex RA volumes to be sold in spring Market Offer
IOU Procurement / Sales Activity	IOUs launch spring RA Market Offer process	April 2022	4/19/2022	2023	Inform market of System/Flex RA volumes to be offered
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast peak-loads for 2023
IOU Procurement / Sales Activity	CAM review of selections	Coincident with completion of Market Offer	5/3/2022	2023	Review offer selections with CAM
IOU Procurement / Sales Activity	IOUs complete spring RA Market Offer process	2 weeks after launch	5/3/2022	2023	Execute System/Flex RA sales agreements
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	IOUs submit CAM and PCIA Showing RA volumes to ED	July 2022	7/12/2022	2023	Volumes to be allocated in PCIA Showing for 2023 compliance year are frozen, subject to NQC/EFC adjustment
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares

IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine LSE elections and rough allocation volumes
RA Process	CAISO updates NQC/EFC	September 2021	9/6/2022	2023	Finalize total PCIA-eligible System/Flex RA volumes available for allocation
IOU Procurement / Sales Activity	IOUs launch fall RA Market Offer process	September 2022 1 week after CAISO NQC/EFC Updates	9/13/2022	2023	Inform market of System/Flex RA volumes to be offered
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocations for 2023
IOU Procurement / Sales Activity	CAM review of System/Flex RA selections	Coincident with completion of System/Flex RA Market Offer	10/4/2022	2023	Review offer selections with CAM
IOU Procurement / Sales Activity	IOUs complete fall RA Market Offer process	October 2022 2 weeks after Year-Ahead updates	10/4/2022	2023	Sell unallocated System/Flex RA volumes and re-allocate unsold volumes
RA Process	Year-Ahead RA filing due to ED & CAISO	October 31, 2021	10/31/2022	2023	Allocations are shown for LSEs accepting allocations or buying sold PCIA Showing RA capacity
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish shown System/Flex RA volumes, vintaged coincident peak-loads, and forecast MPBs for 2023.
IOU Procurement / Sales Activity	Payment owed for allocations and sales	~20 days following close of compliance month	2/20/2023	2023	LSES accepting allocations or sales to pay for shown System/Flex RA
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible System/Flex RA volumes
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2023-24	Publish true-up MPB for 2023. Publish shown System/Flex RA volumes, vintaged coincident peak-loads, and forecast MPBs for 2024.
IOU Procurement / Sales Activity	True-Up Payment Owed for Allocations	December 2023	12/15/2023	2023	LSEs accepting allocations to pay true-up payment relating to difference between forecast and actual MPB
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative Local RA Allocation Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Compliance Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2024-25	Introduce discussion of vintaged peak load forecasting methodologies and PCIA Showing implementation
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2024-25	Request approval to conduct allocations
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2024-25	Receive approval to conduct allocations
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2024-25	Publish forecasted PCIA-eligible Local RA volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2024-25	Rule upon vintaged coincident peak-load forecasting methodologies and PCIA Showing
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2024-25	Publish forecasted PCIA-eligible Local RA volumes
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.

IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, coincident, peak-load shares for allocation of RA credit
IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2024-25	Commence process of determining vintaged, coincident peak-load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2024-25	Forecast peak-loads for 2023, which will be applied to 2024-25
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2024-25	Publish forecasted PCIA-eligible Local RA volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	IOUs submit CAM and PCIA Showing RA volumes to ED	July 2022	7/12/2022	2024-25	Volumes to be allocated for 2022 filing year in PCIA Showing are frozen, subject to NQC adjustment
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2024-25	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2024-25	Update assumptions for calculating allocation shares
RA Process	CAISO updates NQC/EFC	September 2021	9/6/2022	2024-25	Finalize total PCIA-eligible Local RA volumes available for allocation
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2024-25	Establish final allocations for 2024-25

RA Process	Year-Ahead RA filing due to ED & CAISO	October 31, 2021	10/31/2022	2024-25	Allocations are shown for LSEs accepting allocations or buying PCIA Showing Local RA capacity sold in secondary market
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2024-25	Publish shown Local RA volumes and vintaged coincident peak-loads for 2024-25.
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024-26	Publish forecasted PCIA-eligible Local RA volumes
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2024-26	Publish shown Local RA volumes and forecasted, vintaged coincident peak-loads for 2024-26.

Appendix K

LIST OF ACRONYMS

List of Acronyms

AB – Assembly Bill

ALJ – Administrative Law Judge

AReM – Alliance for Retail Energy Markets

AWEA – American Wind Energy Association of California

BPP – Bundled Procurement Plan

CAISO – California Independent System Operator

Cal PA – Public Advocates Office

CalCCA – California Association of Community Choice Aggregators

CAM – Cost Allocation Mechanism

CCA – Community Choice Aggregator

CEC – California Energy Commission

CLECA – California Large Energy Consumers Association

Commercial – Commercial Energy

CNS – Clean Net Short

CPE – Central Procurement Entity

CPM – Capacity Procurement Mechanism

CPUC or Commission – California Public Utilities Commission

CTC – Competition Transition Charge

CUE – Coalition of California Utility Employees

D. – Decision

DA – Direct Access

DACC – Direct Access Customer Coalition

DR – Demand Response

ED – CPUC's Energy Division

EFC – Effective Flexible Capacity

ERRA – Energy Resource Recovery Account

ESP – Energy Service Provider

FERC – Federal Energy Regulatory Commission

FPP – Fuel & Purchased Power

GHG – Greenhouse Gas

GRC – General Rate Case

Guide – Procurement Process Reference Guide

IE – Independent Evaluator

IOU – Investor Owned Utility

IRP – Integrated Resources Plan

kW – kilowatt

kWh – kilowatt-hour

LSA – Large-Scale Solar Association

LSE – Load Serving Entity

mo – month

MPB – Market Price Benchmark

MW – megawatt

MWh – megawatt-hour

NDA – Non-Disclosure Agreement

NQC – Net Qualifying Capacity

O&M – Operations and Maintenance

OIR – Order Instituting Rulemaking

PABA – Portfolio Allocation Balancing Account

PAM – Portfolio Allocation Mechanism

PCC – Portfolio Content Category

PCIA – Power Charge Indifference Amount, including the CTC

PCL – Power Content Label

PG&E – Pacific Gas & Electric

POC – Protect Our Communities Foundation

PPA – Power Purchase Agreement

PRG – Peer Review Group

PSDP – CEC's Power Source Disclosure Program

Q – Quarter (*i.e.,* 3 months of a calendar year)

QCR – Quarterly Compliance Review

NDA – Non-Disclosure Agreement

NQC – Net Qualifying Capacity

R. – Rulemaking

RA – Resource Adequacy

RAAIM – Resource Adequacy Availability Incentive Mechanism

REC – Renewable Energy Credit

RFI – Request for Interest

RPS – Renewables Portfolio Standard

RSP – Reference System Plan in IRP

SCE – Southern California Edison

SDG&E – San Diego Gas & Electric

Shell – Shell Energy

SJCE – San Jose Clean Energy

TAC – Transmission Access Charge

UCAN – The Utilities Consumers' Action Network

UCAP – Unforced Capacity Availability Protocol

UOG – Utility-Owned Generation

VAAC – Voluntary Allocation and Auction Clearinghouse

VAMO – Voluntary Allocation and Market Offer

WG – Working Group in Phase 2 of R.17-06-026

WREGIS – Western Renewable Generation Information System