VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 9

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: November 10, 2021

Please find attached Keyes & Fox's October 2021 Regulatory Memorandum dated November 4, 2021, an informational summary of the key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC).

Attachment: Keyes & Fox Regulatory Memorandum dated November 4, 2021.

KEYES&FOX LLP

Valley Clean Energy Alliance

Regulatory Monitoring Report

To:	Valley Clean Energy Alliance ("VCE") Board of Directors
From:	Sheridan Pauker, Partner, Keyes & Fox, LLP Tim Lindl, Partner, Keyes & Fox LLP Ben Inskeep, Principal Analyst, EQ Research, LLC
Subject:	Regulatory Update
Date:	November 4, 2021

Summary

Keyes & Fox LLP and EQ Research, LLC, are pleased to provide VCE's Board of Directors with this monthly informational memo describing key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC). A Glossary of Acronyms used is provided at the end of this memo.

In summary, this month's report includes regulatory updates on the following priority issues:

- **Ensuring Summer 2021 Reliability:** On October 29, 2021, the CPUC issued a Proposed Decision approving VCE's proposed agricultural irrigation pumping DR pilot, with some modifications.
- **New: Safety Culture Assessments**: The CPUC opened R.21-10-001 and issued a new Order Instituting Rulemaking for developing and adopting safety culture assessments under SB 901. Comments on the preliminary scope and schedule are due November 29, 2021.
- **PG&E's Phase 2 GRC:** On October 18, 2021, the ALJ issued a Proposed Decision in PG&E's Phase 2 GRC regarding revenue allocation and rate design issues.
- **PG&E's Phase 1 GRC:** The Assigned Commissioner issued a Scoping Memo and Ruling establishing a scope and procedural schedule, as well as ruling on various motions. On October 8, 2021, PG&E filed a motion requesting permission to file supplemental testimony, to which TURN replied on October 25, 2021.
- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** The ALJ issued a Proposed Decision that would adopt a Wildfire Fund NBC of $0.00652/kWh for January 1, 2022, through December 31, 2022.
- **New: RA Rulemaking (2023-2023):** On October 11, 2021, the CPUC issued an Order Instituting Rulemaking, opening this rulemaking as the successor rulemaking to the RA Rulemaking (2021-2022) to consider RA oversight and reforms applicable to LSEs for the 2023 and 2024 compliance years. Parties filed opening comments on the OIR on November 1, 2021.
- **RA Rulemaking (2021-2022):** Workshops were held to develop PG&E's Slice-of-Day proposal and related RA program structural reform. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on

October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the RA Rulemaking (2023-2024) closed this proceeding, except to resolve OhmConnect's Petition for Modification.

- **RPS Rulemaking:** Parties filed comments and reply comments on the Proposed Decision and Commissioner Rechtschaffen's Alternate Proposed Decision, both of which would significantly modify the RPS program confidentiality rules.
- **IRP Rulemaking:** Parties filed reply comments in response to party comments on the August 17, 2021 ALJ Ruling on a proposed Preferred System Plan. VCE and other LSEs made compliance filings by the October 15, 2021 deadline in response to a September 23, 2021, ALJ Ruling directing LSEs to formally file updated IRP information in the docket that had previously been informally provided to the Energy Division. Parties also filed comments and reply comments, in response to an October 13, 2021, Ruling that requested comments on natural gas issues. On October 26, 2021, California Community Power, of which VCE is a member, issued a Request for Offers for up to 200 MW of Firm Clean Resources (i.e., geothermal or biomass) with deliveries beginning no later than June 1, 2026.
- **PG&E 2022 ERRA Forecast:** PG&E filed rebuttal testimony, and parties filed opening and reply briefs.
- **PG&E's 2019 ERRA Compliance:** Energy Division hosted a workshop on the IOU proposed methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events.
- **PCIA Rulemaking:** Parties filed comments and reply comments on the September 17, 2021, Ruling requesting comments on ERRA and PCIA issues. PG&E also requested to delay implementation of the line-item presentation of the PCIA on bundled customer bills from December 31, 2021, until October 1, 2023.
- **PG&E's 2020 ERRA Compliance:** Parties filed a Settlement Agreement resolving disputed issues in this proceeding.
- **Provider of Last Resort Rulemaking:** Golden State Power Cooperative filed a Motion to remove the state's electric cooperatives as respondents to the proceeding. A workshop was held on October 29, 2021, to review the operation and expectation of POLR service, registration, and financial security requirements.
- **Investigation into PG&E's Organization, Culture and Governance:** CPUC President Batjer sent a letter to PG&E stating that its execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action.
- **PG&E Regionalization Plan**: No updates this month. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.
- **Direct Access Rulemaking**: No updates this month. In August, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.
- **RA Rulemaking (2019-2020):** No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.
- **Miscellaneous Updates:**
    - The CPUC, as part of its continued efforts to hold PG&E accountable for its safety performance, will hold a remote (virtual) public workshop on November 8, 2021, to discuss and obtain public feedback on the Corrective Action Plan PG&E submitted after the CPUC placed the company in an Enhanced Oversight and Enforcement Process.
    - The Performance Audit of PG&E Wildfire Mitigation Plan Expenditures Final Report was issued October 11, 2021. It found that PG&E only met one of three objectives. The audit

identified total PG&E questioned costs of $59.8 million (e.g., recommended that PG&E not be able to recover these costs in rates) and nearly $1.5 billion in future potential incrementality concerns for Energy Safety to consider.

  - CPUC President Marybel Batjer announced she would resign at the end of 2021. CPUC Deputy Executive Director for Energy and Climate Policy and head of the Energy Division, announced he was stepping down as well.

Ensuring Summer 2021 Reliability

On October 29, 2021, the CPUC issued a Proposed Decision that would approve VCE's proposed agricultural irrigation pumping DR pilot, with some modifications. The PD would also adopt numerous other supply- and demand-side changes to address near-term reliability concerns, although the 2,000-3,000 MW procurement mandate would apply specifically to the IOUs.

- **Background**: CAISO experienced rolling blackouts (Stage 3 Emergency) on August 14, 2020 and August 15, 2020 when a heatwave struck the Western U.S. and there was insufficient available supply to meet high demand. The OIR was issued to ensure reliable electric service in the event that an extreme heat storm occurs in the summer of 2021.

  D.21-03-056 instituted modifications to the planning reserve margin (PRM), effectively increasing the PRM beginning summer 2021 from 15% to 17.5%. For 2021, this results in a minimum target of incremental procurement of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E. The net costs associated with this incremental procurement would be shared by all customers (including CCA customers) in each IOU's service territory. It also authorized the IOUs to implement a Flex Alert paid media campaign program to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid and adopts modifications and expansions to the Critical Peak Pricing (CPP) program, to be in place for the summer of 2021. D.21-03-056 also established an ELRP to provide emergency load reduction and serve as an insurance policy against the need for future rotating outages. The initial duration of the ELRP pilot program is five years, 2021-2025. After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate ($1,000/MWh for up to an annual 60-hour limit) applied to incremental load reduction. For PG&E, the budget caps are $3.9 million for administration and $28.6 million for customer compensation.

  On August 10, 2021, the Assigned Commissioner issued an Amended Scoping Memo and Ruling addressing Gov. Newsom's emergency proclamation on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day by scoping the current phase of the proceeding to include changes that would increase supply and decrease demand to ensure reliability in the summer of 2022 and 2023.

  VCE's testimony and briefs requested that the CPUC approve VCE's proposal for an Agricultural Demand Flexibility Pilot and approve Polaris' proposal for Demand Flexibility Pilots in IOU territories. VCE's proposed pilot would be made available to 5 MW of customer load on irrigation pumping tariffs. The pilot would include automation of these loads to receive dynamic price signals and implementation of an experimental rate that incorporates dynamic energy and capacity charges in hourly prices. Customers who successfully respond to the price signals and shift load out of expensive hours—typically the ramp hours—will enjoy bill savings and the total cost to serve VCE customers would be reduced.

- **Details**: **VCE Pilot:** The PD would approve VCE's dynamic rate pilot for three years (2022-2024), and direct that it start no later than May 1, 2022. Customers participating in VCE's dynamic rate pilot will receive a "shadow bill." PG&E may bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the existing tariff. For the generation components of the service by VCE, (1) energy costs will be based on CAISO wholesale market prices, and (2) generation capacity and flexible capacity costs will be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit. For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges. Non-generation and non-delivery costs (e.g., transmission rates and non-bypassable charges) of the pilot will be recovered through existing rate structures. The pilot scale will be limited to 5 MW of peak load. The PD would direct PG&E to provide funds to or reimburse VCE for crediting any savings realized by the customers with respect to the delivery component of the VCE dynamic rate pilot in the customers' shadow bills. In response to PG&E's assertion that it is not appropriate to use AutoDR or Public Purpose Program funds for enrolling/integrating loads into the pilot program, the CPUC authorized new funding of $3.25 million for the administration and execution of the three-year pilot. VCE and/or PG&E may engage a service provider with a suitable IT platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps. The PD would require PG&E to conduct a mid-term and final evaluation of this pilot. The mid-term evaluation report is due December 31, 2023, and a final evaluation is due March 1, 2025.

Procurement Mandate for IOUs: The PD would create an additional procurement mandate of 2,000 MW-3,000 MW for 2023, allocated exclusively to the three large IOUs (900 MW-1,350 MW each for PG&E and SCE, and 200 MW-300 MW for SDG&E). The PD also would require all incremental resources procured as a result of this proceeding to be available during net peak.

Demand-Side Changes: The PD would adopt the following demand-side changes:

- Expands on the Emergency Load Reduction Program (ELRP) adopted in Phase 1 of this proceeding, including removing the eligibility requirement that Group A.1 participants in ELRP not take current service on a critical peak pricing or real-time pricing equivalent tariff. A.2 group is expanded to include non-Base Interruptible Program (non-BIP) aggregators of non-residential, non-BIP customers. Residential Net Energy Metering customers meeting the eligibility standards outlined for Group A.3 participants are eligible to participate in ELRP.
- Modifies the ELRP aimed to increase participation and provide clarity in guidance. Among these modifications, the compensation rate of ELRP is expanded to $2/kWh.
- Adds an ELRP program (ELRP Group A.6) that allows residential customers to opt-in to receive compensation for reductions in energy use during system emergencies, with special outreach to low-income customers and customers in Disadvantaged Communities. Customers may not simultaneously be enrolled in another supply side DR program offered by an IOU, third-party DR provider or CCA. Customers likewise may not be taking service on a critical peak pricing, SmartRate or similar dynamic rate tariff. Finally, a CCA may elect not to participate in the Residential ELRP pilot adopted here, in which case its customers would be ineligible to enroll. The CCA must make its election by January 31 of a new ELRP pilot year.
- Expands on electric vehicle potential by allowing aggregation of vehicle to grid managed charging and discharge to support the grid at net peak.
- Broadens the Flex Alert media campaign to focus on the new Residential ELRP program and continue existing activities into 2022 and 2023.
- Makes changes to existing Demand Response programs, both on a statewide basis and to individual programs that pertain to each major electric Investor-Owned Utility.
- Approves a large smart thermostat incentive program ($75/thermostat incentive) designed to reduce air conditioning a few degrees during emergencies, with special protection for low-income customers that qualify for the Energy Savings Assistance Program.

    - Adds pilots to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies. This includes the VCE pilot described above, and an SCE-supported pilot.

  Supply-Side Changes: The PD would adopt the following supply-side changes:

    - Allows energy storage projects that are not fully deliverable as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. IOUs can collect the costs of this procurement through distribution rates until the resource is fully deliverable to CAISO markets; after that, net capacity costs and benefits will be accounted for through the CAM mechanism.
    - Expands use of a centralized procurement entity as a means of procuring reliability resources located in local areas. Specifically, it would allow SCE and PG&E to negotiate bilateral contracts for the procurement mandated in the PD in their capacities as Central Procurement Entities.
    - Encourages accelerated on-line dates for procurement already ordered. The PD declines to develop a new incentive regime for LSEs or generators to bring IRP procurement on earlier than expected. The PD also declines to introduce penalties for delays to the IOU and LSE procurement ordered in D.19-11-016 and declines to increase penalties already adopted for failures in RA procurement.

- **Analysis**: If adopted, the PD would approve VCE's proposed agricultural pumping DR pilot and direct PG&E to work with VCE on implementation. The PD outlines specific requirements for the pilot, as well as requiring an advice letter compliance filing by VCE. The PD would make numerous other changes designed to increase supply and decrease demand during net peak periods, but it largely focuses on IOUs to achieve its aims, including expanding the Central Procurement Entity function of PG&E and SCE to allow for additional procurement. LSEs are encouraged to accelerate their procurement previously ordered in D.21-06-035, but are not required to do so, and the PD declines to adopt an incentive for LSEs to accelerate procurement.

- **Next Steps**: Comments and reply comments on the PD are due November 10, 2021, and November 16, 2021, respectively. The PD may be considered, at the earliest, at the CPUC's December 2, 2021, Business Meeting.

  If the PD is adopted, VCE (in coordination with PG&E) must submit a Tier 1 Advice Letter no later than 60 days after issuance of the CPUC's final decision that includes the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.

- **Additional Information**: Proposed Decision (October 29, 2021); Ruling taking notice of Revised Summer Stack Analysis (September 30, 2021); D.21-09-045 denying rehearing of D.21-03-056 (September 23, 2021); Ruling providing Staff Concepts Proposal (August 16, 2021); Ruling noticing CEC draft Preliminary 2022 Summer Supply Stack Analysis (August 12, 2021); Amended Scoping Memo and Ruling (August 10, 2021); D.21-06-027 (approved June 24, 2021); Order denying applications for rehearing (May 20, 2021); D.21-03-056 (March 25, 2021); D.21-02-028 directing IOUs to seek additional capacity for summer 2021 (February 17, 2021); Scoping Memo and Ruling (December 21, 2020); ALJ Ruling and Staff Proposal (December 18, 2020); Order Instituting Rulemaking (November 20, 2020); Docket No. R.20-11-003.

New: Safety Culture Assessments

On October 7, 2021, the CPUC opened R.21-10-001 and issued a new Order Instituting Rulemaking for developing and adopting safety culture assessments under SB 901.

- **Background**: IOU safety culture assessments are required as part of AB 1054 and SB 901. AB 1054 directed the CPUC's Wildfire Safety Division, now the Office of Energy Infrastructure Safety, to conduct annual safety culture assessments of each electrical corporation, the first of which will be published in fall 2021. The AB 1054 assessments are specific to wildfire safety efforts and include a workforce survey, organizational self-assessment, supporting documentation, and interviews. SB 901 directs the CPUC to establish a safety culture assessment for each electrical corporation, conducted by an independent third-party evaluator. SB 901 requires that the CPUC set a schedule for each assessment, including updates to the assessment, at least every five years, and prohibit the electrical corporations from seeking reimbursement for the costs of the safety culture assessments from ratepayers. This rulemaking implements SB 901.

- **Details**: This proceeding will implement the statutory requirements of SB 901 relating to the Commission's assessment of safety culture for regulated utilities. It will examine what methodologies should be employed in the safety culture assessments to ensure results are comparable across IOUs and can measure changes in IOU safety culture over time. It will also consider adopting the process and framework to oversee safety culture assessments of gas utilities and gas storage operators, in addition to electrical corporations as required by SB 901. It will consider requiring that IOUs implement specific safety management practices to improve safety culture through adoption of a Safety Management System standard, consider adopting a maturity model to use in safety culture assessments, and determine accountability metrics.
- **Analysis**: This rulemaking will assess the safety culture of PG&E and other IOUs in California. While its direct focus is on IOUs like PG&E, it could impact VCE and its customers to the extent it influences PG&E's safety culture and contributes to the safety of VCE customers, as well as the rates VCE customers pay to PG&E to mitigate or address safety issues (e.g., wildfires caused by PG&E transmission equipment; explosions from PG&E natural gas infrastructure, etc.).
- **Next Steps**: Comments on the preliminary scope and schedule are due November 29, 2021. Reply comments are due December 29, 2021.
- **Additional Information**: Order Instituting Rulemaking (October 7, 2021); Docket No. R.21-10-001.

PG&E's Phase 2 GRC

On October 18, 2021, the ALJ issued a Proposed Decision in PG&E's Phase 2 GRC regarding revenue allocation and rate design issues, which also adopts, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; EDR settlement; agricultural rate design; C&I rate design) and revenue allocation.

- **Background**: PG&E's 2020 Phase 2 General Rate Case (GRC) addresses marginal cost, revenue allocation and rate design issues covering the next three years. PG&E's pending Phase 1 GRC (filed in December 2018 via a separate proceeding) will set the revenue requirement that will carry through to the rates ultimately adopted in this proceeding.

  In this proceeding, PG&E seeks modifications to its rates for distribution, generation, and its public purpose program (PPP) non-bypassable charge. PG&E proposes to implement a plan to move all customer classes to their full cost of service over a six-year period (the first three years of which are covered by this GRC Phase 2) via incremental annual steps. PG&E proposes to use marginal costs for purposes of revenue allocation and to adjust distribution one-sixth of the way to full cost of service each year over a six-year transition period.

  Of note, PG&E is proposing changes to the DA/CCA event-based fees that were not updated in the 2017 Phase 2 GRC proceeding. In addition, PG&E proposes to remove the PCIA revenue from bundled generation revenue and allocate that cost separately to bundled customers, collecting the PCIA from bundled customers on a non-time differentiated, per-kWh basis (i.e., the same way it is collected from DA/CCA customers). PG&E will continue to display the PCIA with other generation charges on customer bills, but will unbundle the PCIA as part of unbundled charges in each rate schedule.

Five settlement agreements are pending. The **Revenue Allocation Supplemental Settlement Agreement** resolves all of the inter-class revenue allocation issues. Regarding bundled PCIA allocation, the parties agreed to remove PCIA at present rates before allocation and reallocate to the classes in proportion to the adopted generation allocation. The settling parties also agreed to keep in Distribution the revenues for DR programs and EV programs. The settling parties agreed to move Energy Efficiency Incentives revenues from Distribution to Public Purpose Programs and allocate them by the Equal Percentage of Total Revenue method.

The **Agricultural Rate Design Supplemental Settlement Agreement** resolves the agricultural rate design issues in this proceeding, except for the issue of a proposed bill credit for PSPS events. The settling parties agreed to the rate designs proposed by PG&E in its opening testimony, for default Schedules AG-A1, AG-A2, AG-B, and AG-C and opt-in Schedules AG-FA, AG-FB, and AG-FC, as well as the demand charge rate limiter for Schedule AG-C, the elimination of the monthly TOU meter charge, maintaining the status quo for the Optimal Billing Period Program, and Peak Day Pricing provisions. Additionally, settling parties agreed to create new optional rate Schedules AG-A3 and AG-B2 that reduce the summer off-peak energy charges below the electric bundled system average rate. The settling parties agreed that the following four issues should not be decided in this case: A new 10-year legacy TOU period, a springtime rate or balancing account adjustment, daily demand charges, and an account or demand aggregation program.

In the **Economic Development Rate (EDR) Supplemental Settlement Agreement** settling parties reached a settlement agreement to continue the EDR program with program-related rate reductions. PG&E’s EDR rate reduces both the transmission, distribution, and the generation portions of customer bills. The settlement would provide that the EDR discount should be set in a way that enables CCAs to offer comparable rates, and PG&E and Joint CCAs agreed to a collaborative process to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E’s EDR. The rate reductions for EDR will be separated between generation and distribution amounts, with the deduction to the generation portion specified in the settlement agreement being substantially less than under the current allocation.

The **Commercial and Industrial Rate Design Supplemental Agreement** resolves Commercial and Industrial rate design issues, apart from the issue of CPUC action on the design of PG&E’s transmission rates. The settling parties agreed that PG&E should set bundled PCIA initially equal to the most recent vintage PCIA, but use the adopted allocation for generation to set going forward PCIA rates. PG&E would set SOP rates to recover at least the PCIA. The tariff presentation of the PCIA for bundled generation rates would be modified as set forth in PG&E’s rebuttal testimony, which proposed alternative tariff language in response to Joint CCAs’ proposals.

The **Residential Rate Design Supplemental Settlement Agreement** resolves all residential rate design issues in the proceeding, including:

- The PCIA will be identified for bundled customers as a flat rate (not differentiated by season or TOU period).
- PG&E’s proposal for tiered rate levels for Schedule E-1 should be approved.
- PG&E’s proposal to keep the Schedule E-TOU-C (*i.e.,* default residential TOU rate) peak versus off-peak price differentials at their current levels until 12 months after the last cohort of PG&E’s customers are migrated to default TOU rates should be approved, and future changes over the following three years are specified in the Settlement Agreement.
- PG&E’s Schedule E-ELEC should be approved, with the fixed charge set at $15 per customer per month. Since this new E-ELEC rate requires structural changes to PG&E’s billing system, PG&E anticipates that it would take at least twelve months after a final decision is issued in this proceeding before it could be programmed, tested, and implemented.

  - PG&E will host two workshops to discuss the collection of key information regarding customers who engage in electrification efforts, and the data collected will be provided to interested stakeholders and the Commission as part of a formal Measurement and Evaluation (M&E) study.

- **Details**: The PD largely adopts PG&E's proposed marginal costs and methodologies for deriving them but adopts marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association. It also adopts, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; EDR settlement; agricultural rate design; C&I rate design) and revenue allocation.

  With respect to CCA issues, the EDR settlement that would be adopted by the PD notes that PG&E and the Joint CCAs agreed to create a collaborative process "to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR." The PD would also approve the agricultural rate design settlement that proposed that the unbundling of the PCIA from the generation component of bundled rates be designed as a flat PCIA rate, not differentiated by season or TOU period, consistent with the PCIA rate design for DA and CCA customers. The PCIA rate for bundled customers would use the most recent vintage of the PCIA rate. Finally, the PD would approve the revenue allocation settlement, including its proposal that before allocating generation revenue, instead of including the PCIA revenue in the overall generation revenue requirement, PCIA revenue will be removed from each customer class's revenue at present rates based on the most recent vintage PCIA rates. Then, PG&E will use the adopted allocation for generation to allocate the PCIA revenue requirement to customer classes.

- **Analysis**: The PD, if adopted, would affect the allocation of PG&E's revenue requirements among VCE's different rate classes and the rate design of PG&E's customers. It will also affect distribution and PPP charges paid by VCE customers to PG&E. PG&E's proposed CCA fee revisions were unopposed, and would increase the cost VCE pays to PG&E for various services, to the extent VCE uses these services.

- **Next Steps**: Comments on the PD are due November 8, 2021, and replies are due November 15, 2021. An evidentiary hearing on RTP issues is scheduled for January 24-26, 2021, followed by opening briefs in February 2022, reply briefs in March 2022, a proposed decision in June 2022, and a decision in July 2022.

- **Additional Information**: Amended Scoping Memo and Ruling (August 25, 2021); Ruling directing PG&E to provide marginal cost scenarios (June 16, 2021); Motion to adopt Commercial and Industrial Rate Design Supplemental Agreement (April 13, 2021); Motion to adopt Revenue Allocation Supplemental Settlement Agreement (April 8, 2021); Motion to adopt Agricultural Rate Design Supplemental Settlement Agreement (April 8, 2021); Motion to adopt Economic Development Rate (EDR) Supplemental Settlement Agreement (April 8, 2021); Motion to adopt residential rate design settlement (March 29, 2021); Notice of Virtual Evidentiary Hearing (March 25, 2021); Scoping Memo and Ruling (February 16, 2021); Ruling bifurcating RTP issues into separate track (February 2, 2021); PG&E Status Report (December 18, 2020); D.20-09-021 on EUS budget (September 28, 2020); Ruling extending procedural schedule (July 13, 2020); Exhibit (PG&E-5) (May 15, 2020); Scoping Memo and Ruling (February 10, 2020); Application, Exhibit (PG&E-1): Overview and Policy, Exhibit (PG&E-2): Cost of Service, Exhibit (PG&E-3): Revenue Allocation, Rate Design and Rate Programs, and Exhibit (PG&E-4): Appendices (November 22, 2019); Docket No. A.19-11-019.

PG&E Phase 1 GRC

The Assigned Commissioner issued a Scoping Memo and Ruling on October 1, 2021. On October 8, 2021, PG&E filed a motion requesting permission to file supplemental testimony, to which TURN replied on October 25, 2021.

- **Background**: Phase 1 GRC applications cover the revenue requirement, including the functionalization of costs into categories such as electric distribution or generation, which impact which customers (bundled, unbundled, or both) pay for the costs through rates. Phase 2 GRC applications cover cost allocation (i.e., assigning costs to customer classes, such as Residential) and rate design issues. PG&E proposes to have a second and third track of this Phase 1 GRC to request reasonableness review of certain memorandum and balancing account costs to be recorded in 2021 and 2022. PG&E will file its next Phase 2 GRC application by September 30, 2021.

  On August 25, 2021, the CPUC Executive Director granted PG&E's request to delay filing its next Phase 2 GRC application until September 30, 2024.

  In their protest of PG&E's application, the Joint CCA parties identified the following list of preliminary issues they plan to examine or address in this proceeding:

  - **Compliance with the Commission's Cost Allocation Directives in D.20-12-005** (PG&E's most recently decided Phase 1 GRC decision), including PG&E's cost functionalization methodology, wildfire costs, and allocation of Customer Care costs.
  - **Reinvestments in and Recovery of Legacy Owned Generation Costs**, including solar contract renewals or the decommissioning of legacy owned assets, which impact Joint CCAs' customers through the PCIA and related vintaging of costs.
  - **Other Issues that May Require Further Investigation and Analysis**, including how costs related to PSPS Events should be tracked and allocated; whether and how any funds that PG&E receives as credits (such as Department of Energy settlement funds) should be allocated to departing load customers; and how PG&E's regionalization proposal impacts its relationship and dealings with CCAs and their customers.

  In August, TURN also filed a Motion requesting a Ruling requiring PG&E to supplement its proposal with an alternative spending plan that limits the growth in proposed spending by the rate of inflation.

- **Details**: The Scoping Memo and Ruling divides the proceeding into two tracks. Track 1 will address the majority of matters, including PG&E's requested revenue requirement together with safety and environmental and social justice issues. Track 2 will address the narrower matters of the reasonableness of the 2019-2021 actual costs recorded in the named memorandum accounts and balancing accounts and, to the extent relevant, also address safety and environmental and social justice.

  In addition to establishing the scope and schedule of the proceeding, the Scoping Memo and Ruling directed PG&E to serve testimony to seek approval for any revisions to the forecasted expenditures for its 10,000-mile undergrounding proposal that fall within the timeframe covered by this proceeding. In addition, in an effort to further explore the available affordability metrics based on a motion by TURN, the Scoping Memo and Ruling directed PG&E to work with Energy Division to prepare an analysis, due one month before intervenor testimony is due. However, TURN's motion requesting a Ruling requiring PG&E to supplement its proposal with an alternative spending plan that limits the growth in proposed spending by the rate of inflation was denied.

  PG&E's supplemental testimony addresses two proposals. The first is PG&E's proposal for a mechanism to allow substantial capital accounting policy changes within the 2023 GRC cycle that would provide rate reductions to customers. The goal of the mechanism would be to return to customers the annual expense revenue requirement for newly capitalized programs exceeding $10 million annually, net of any capital revenue requirement associated with the programs' adopted funding. The second is PG&E's proposal to revise the Transportation Electrification Balancing Account (TEBA) to establish two new two-way subaccounts to record and recover costs of electric distribution capacity additions and new interconnection requests to account for the potential rapid growth in EV adoption and the resulting need for electric infrastructure to support EV charging.

- **Analysis**: This proceeding will set the revenue requirement, and thereby ultimately impact PG&E's rates, for 2023-2026. It will establish how the revenue requirement components will be functionalized, which impact whether the ultimately approved costs will be borne by PG&E bundled customers, unbundled customers like VCE customers, or both. It will also address numerous other issues raised in PG&E's application that could impact rates, policies, and programs implemented by PG&E.
- **Next Steps**: The next steps in Track 1 are public participation hearings in January/February 2022, a PG&E status report in February 2022 regarding changes to its cost forecast for wildfire programs, a PG&E affordability metrics report at least one month before intervenor testimony, PG&E testimony on its 2021 recorded expenditures by March 22, 2022, and intervenor testimony on April 29, 2022. Proposed and final decisions are anticipated in Q2 2023.

  In Track 2, public participation hearings are scheduled for November 2022, and intervenor testimony is due November 14, 2022. A proposed decision is anticipated in Q2 2023, and a final decision is anticipated in Q3 2023.
- **Additional Information**: Motion of PG&E to submit supplemental testimony (October 15, 2021); Scoping Memo and Ruling (October 1, 2021); PG&E Application (June 30, 2021); Docket No. A.21-06-021.

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

On October 29, 2021, the ALJ issued a Proposed Decision that would adopt a Wildfire Fund NBC of $0.00652/kWh for January 1, 2022, through December 31, 2022.

- **Background**: This rulemaking continues to implement AB 1054, which extended a non-bypassable charge on ratepayers to fund the Wildfire Fund. The CPUC issued D.20-12-024 in December 2020 that continues the Wildfire Non-Bypassable Charge (NBC) amount of $0.00580/kWh for January 1, 2021, through December 31, 2021. The NBC amount of 2022 and 2023 will be established in this proceeding.
- **Details**: The proposed 2022 Wildfire Fund Non-Bypassable Charge is $0.00652/kWh, up from $0.0058/kWh in 2021. The reason for this proposed increase is that the Department of Water Resources demonstrated a collection shortfall of $13.0 million for 2021 and $85.0 million for 2020 (due largely to a lag in initiating and remitting IOU collections for the Wildfire Fund NBC to DWR at the outset of the Wildfire Fund NBC's existence). Therefore, because of this total $98.0 million under-collection in 2020 and 2021, the 2022 Wildfire Fund NBC is obliged to collect both this 2020-2021 shortfall and the 2022's necessary revenue requirement of $902.4 million.
- **Analysis**: VCE customers will pay the 2022 and 2023 Wildfire Fund Non-Bypassable Charge amounts established in this proceeding. The proposed charge for 2022 is increasing due to an under-collection of the revenue requirement in 2021 that has been added to the revenue requirement for 2022.
- **Next Steps**: Comments and reply comments, respectively, are due November 18, 2021, and November 23, 2021. A Decision is expected to be issued in December. (The same timeline used in 2021 to determine the 2022 Wildfire Fund NBC will also apply in 2022 to establish the 2023 Wildfire Fund NBC amount.)
- **Additional Information**: Proposed Decision on Wildfire NBC for 2022 (October 29, 2021); Ruling requesting comments on 2022 Wildfire Fund NBC (September 8, 20210: Scoping Memo and Ruling (June 8, 2021); Order Instituting Rulemaking (March 10, 2021); Docket No. R.21-03-001.

KEYES&FOX LLP

New: RA Rulemaking (2023-2024)

On October 11, 2021, the CPUC issued an Order Instituting Rulemaking (OIR), opening this rulemaking as the successor rulemaking to R.19-11-009 to consider RA oversight and reforms applicable to LSEs for the 2023 and 2024 compliance years. Parties filed opening comments on the OIR on November 1, 2021.

- **Background**: In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops. The PG&E Slice of Day Framework will establish RA requirements based on a "slice-of-day" framework, which seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours. The proposal also attempted to ensure there is sufficient energy on the system to charge energy storage resources. The proposed framework would establish RA requirements for multiple slices-of-day across seasons and would establish a counting methodology to reflect an individual resource's ability to produce energy during each respective slice (e.g., six four-hour periods of the day).
- **Details**: The OIR establishes two tracks to this rulemaking. First, the ongoing major RA structural reforms being considered through a workshop process based on PG&E's "slice-of-day" proposal (previously referred to as "Track 3B.2" in the R.19-11-009 RA rulemaking), is now the "Reform Track" in this rulemaking. All other issues relating to RA procurement obligations and program implementation details will be separated into an "Implementation Track." The Implementation Track will address Local RA requirements for 2023-2026, Flexible RA requirements for 2023-2024, potential modifications to the Central Procurement Entity structure and process, potential modifications to the Planning Reserve Margin, potential modifications to Qualifying Capacity Counting Conventions and Effective Load Carrying Capability (i.e., how different types of resources are counted and credited for RA compliance), and refinements to the RA program.
- **Analysis**: This proceeding will determine VCE's RA obligations and applicable RA rules for the 2023-2024 compliance periods. It will also be the forum for determining major RA structural reforms, such as those being discussed related to PG&E's "slice-of-day" proposal. The workshop process on PG&E's Slice of Day proposal could result in major changes to the RA program structure beginning in the 2024 RA compliance year. The new structure would seek to ensure load (including energy storage charging) will be met in all hours of the day, not just during gross peak demand hours and would move RA from a monthly compliance obligation to a seasonal obligation. The details of the framework would be further fleshed out through the workshop process and need to be approved by the CPUC in 2022.
- **Next Steps**: Reply comments on the OIR are due November 10, 2021, and a prehearing conference is scheduled for November 16, 2021. A scoping memo and ruling is anticipated to be issued in December 2021.

  <u>Implementation Track</u>

  - January 2022: party proposals
  - January/February 2022: Workshop(s)
  - February 2022: Comments on proposals
  - February/March 2022: Reply comments
  - April 2022: CAISO publishes draft LCR and FCR Report
  - May 2022: CAISO publishes final LCR and FCR Report
  - May 2022: Proposed Decision
  - June 2022: Final Decision

Reform Track

- September 2021-January 2022: Workshops. The workshops all to run from 10 a.m. to 3 p.m. and are scheduled for November 3, 2021, November 17, 2021, December 1, 2021, December 15, 2021, January 5, 2022, and January 19, 2022.
- February 2022: Workshop Report
- February/March 2022: Comments/reply comments
- Proposed Decision: Summer 2022

- **Additional Information**: Order Instituting Rulemaking (October 11, 2021); Docket No. R.21-10-002.

RA Rulemaking (2021-2022)

On October 6, 2021, and October 20, 2021, workshops were held to develop PG&E's Slice-of-Day proposal and related RA program structural reform. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the successor RA rulemaking, R.21-10-002, closed this proceeding, except to resolve OhmConnect's Petition for Modification.

- **Background**: This proceeding is divided into 4 tracks, with the focus in 2021 being on Tracks 3 and 4, described in more detail below. Going forward, a workshop process will be used to generate an RA restructuring proposal in Q1 2022, with the goal of implementing more substantial program changes in 2023 for the 2024 RA compliance year.

  Track 3A (completed): D.20-12-006, issued December 2020, addressed the issues of the financial credit mechanism and competitive neutrality rules for the CPEs. It approved CalCCA's proposed "Option 2," with modifications, which allows the CPE to evaluate the shown resource alongside bid resources to assess the effectiveness of the portfolio. The financial credit mechanism will apply only to new preferred or energy storage resources (i.e., non-fossil-based resources) with a contract executed on or after June 17, 2020. It also adopted PG&E's competitive neutrality proposal for PG&E's service territory. Finally, D.20-12-006 found that the Local Capacity Requirements Working Group should continue to discuss recommendations and develop solutions for consideration in CAISO's 2022 LCR process.

  Track 3B.1 and Track 4 (completed): D.21-06-029, issued June 2021, adopted local capacity requirements for 2022-2024, flexible capacity requirements for 2022, and refinements to the RA program. It adopted a series of changes to the Maximum Cumulative Capacity (MCC) buckets, which function as limits on the amount of RA that may be procured from resources with different characteristics. It required resources in all MCC buckets to have availability on Saturday for the 2022 RA compliance year. This had the effect of modifying the DR and Categories 1 and 2 buckets to add Saturday. DR contracts with an execution date prior to the effective date of D.21-06-029 will be grandfathered and not subject to the new Saturday availability requirement. It also revised the Category 1 availability criteria (4 consecutive hours of availability from 4-9 p.m. from May-September) to increase the monthly minimum availability from 40 hours to 100 hours (and 96 hours for February) and to require year-round availability. D.21-06-029 requested that the CEC launch a stakeholder working group process as part of the 2021 IEPR and make recommendations on several topics intended to support a comprehensive and consistent DR measurement and verification strategy, to be considered for implementation during the 2023 RA compliance year. Finally, D.21-06-029 added a new RA deficiencies penalty structure to the current penalty structure, layering on a penalty multiplier for repeat RA deficiencies based on a point system beginning in the 2022 RA compliance year.

  Track 3B.2 (Ongoing): D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops. The PG&E Slice of Day Framework will establish RA requirements based on a "slice-of-day" framework, which seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours. The proposal also attempted to ensure there is sufficient energy on the system to charge energy storage resources. The proposed framework would establish RA requirements for multiple slices-of-day across seasons and would establish a counting methodology to reflect an individual resource's ability to produce energy during each respective slice (e.g., six four-hour periods of the day).

- **Details**: OhmConnect's Petition for Modification of D.20-06-031 requested that the CPUC raise the demand response Maximum Cumulative Capacity limit of 8.3% to 11.3%. OhmConnect says that the change is needed to create the room for growth envisioned in D.20-06-031 and meet the requirements of the Governor's Emergency Proclamation ordering state energy agencies to expedite and expand DR programs to reduce the likelihood of future rotating power outages.

  A group of CCAs (RCEA, San Diego Community Power, and San José Clean Energy) and EBCE filed responses in support of OhmConnect's Petition for Modification. The group of CCAs said a higher cap would enable more flexibility for them in meeting their RA requirements, and help California meet system reliability needs. EBCE's reasons for supporting the petition were provided in a confidential attachment to its response.

- **Analysis**: If OhmConnect's Petition for Modification is granted, it would allow LSEs like VCE to procure a higher percentage of demand response resources to meet its RA obligations than it is currently allowed under the RA compliance rules.

- **Next Steps**: This proceeding is now closed, except to resolve OhmConnect's Petition for Modification.

- **Additional Information**: OhmConnect's Petition for Modification (September 9, 2021); D.21-07-014 on restructuring the RA program with PG&E Slice of Day proposal (July 16, 2021); D.21-06-029 adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the RA program (approved June 24, 2021); 2019 Resource Adequacy Report (March 19, 2021); Scoping Memo and Ruling for Track 3B and Track 4 (December 11, 2020); D.20-12-006 on Track 3.A issues (December 4, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

RPS Rulemaking

On October 6, 2021, and October 11, 2021, parties filed comments and reply comments, respectively, on the Proposed Decision (PD) and Commissioner Rechtschaffen's Alternate Proposed Decision (APD), both of which would significantly modify the RPS program confidentiality rules.

- **Background**: This proceeding addresses ongoing RPS issues. VCE submitted its Final 2021 RPS Procurement Plan on February 19, 2021, its Draft 2021 RPS Procurement Plan on July 1, 2021, and its 2020 RPS Compliance Report on August 2, 2021.

  On September 18, 2020, the ALJ issued a Ruling attaching Staff's Proposed Framework for integrating RPS Procurement Plan requirements into the IRP proceeding uses a two-phased approach that makes a relatively minor change to RPS reporting in the current IRP cycle, while fully integrating all elements of RPS Procurement Plans into the next IRP cycle, proposed to commence in the 2023 calendar year (instead of 2022, under the current two-year cycle, although the issue of a two-year versus three-year cycle is not discussed). It is currently unclear when the CPUC will address this proposal.

- **Details**: Current rules allow LSEs to keep procurement prices confidential for the earlier of 3 years *after* the commercial operation date (COD) or 1 year following the expiration of a contract.

Both the PD and APD find that this current window, which typically results in data being held confidential for 5-10 years from the date of contract execution, should be modified.

- **Contracts Not Requiring CPUC Approval (e.g., VCE's contracts):** The PD would order that contract prices and terms become public **30 days** after *the earlier of* the COD or start of delivery date or 3 years after the contract execution date. The APD makes this information public *6 months after contract execution*.
- **REC-Only Contracts***.* The PD would require contract prices and terms for REC-only contracts to be made public 30 days after contract execution for existing facilities, and 30 days after the COD for new facilities. The APD makes this information public for both new and existing facilities 6 months after CPUC approval, or 6 months after the contract execution date where CPUC approval is not required.
- **Competitive Solicitation Information.** The PD first authorizes the release of information on bids that do not result in RPS contracts and RPS bids that are not shortlisted in aggregated form after the final contracts are submitted for CPUC approval where there are at least 3 bidders in a resource category. Additionally, the PD provides a 3-year confidentiality period for individual bidder information after the close of the solicitation. The APD differs from the PD in that it requires individual bidder information to be made public 1 year after final contracts are submitted for CPUC approval or the close of the solicitation (if no contracts are executed).
- **Claims of Confidentiality for RPS Compliance Reports***.* The PDs apply the same rules for all retail sellers, in a continuation of guidance adopted in D.06-06-066. Essentially, securing confidential status will require a retail seller to demonstrate evidence about the type of data and the harm caused by its release to obtain special confidentiality status where a request falls outside the standard confidentiality matrix.
- **Load Forecast & Renewable Net Short.** Currently, per D.06-06-066 retail sellers may utilize a 4-year confidentiality window composed of 3 future years and 1 past year, where the past year refers to the year in which the compliance report is filed. The PDs would shorten the window to 3 years, composed of 2 future years and 1 past year. Thus for the 2022 RPS filings, this information will be confidential for 2022-2024 but the 2025 data would be public. Further, as data becomes 1 year old, it will also become public, such that for the 2022 forecast, the data for 2023 will become public in 2024 when it is 1 year old (and so forth for 2024 data in 2025).
- **Effective Date & Transition Provisions.** Both PDs specify that the rules will become effective immediately upon their adoption for new contracts executed after the date of a Decision. For contracts approved before the effective date, the existing rules are maintained with the exception of expired contracts, which can be made public immediately. RPS compliance reports and any compliance documents submitted on or after January 1, 2022 must follow the revised confidentiality rules.

CalCCA filed comments in support of the PD, arguing that it ensures expanded public access to RPS procurement information while sufficiently protecting market-sensitive information and not disadvantaging any one market participant over another. CalCCA recommended the CPUC reject the APD because the six-month confidentiality protection for contract pricing beginning from the date of contract execution or approval fails to protect market-sensitive information and disadvantages CCAs as compared to IOUs. Finally, CalCCA recommended the CPUC modify Ordering Paragraph 3 of the PD/APD to clarify that a contract amendment does not reduce the otherwise applicable confidentiality window for contract price information.

- **Analysis**: The PD and APD would significantly reduce the period of time for which VCE and other LSEs could keep RPS data confidential, as detailed above.
- **Next Steps**: The PD/APD are scheduled to be considered at the CPUC's November 4, 2021, meeting.
- **Additional Information**: Ruling allowing R.05-06-040 parties to file comments (September 30, 2021); Proposed Decision and Alternate Proposed Decision on RPS confidentiality (September 16, 2021); Ruling aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26,

2021); Ruling extending deadline for draft 2021 RPS Procurement Plan (May 7, 2021); Ruling establishing issues and schedule for 2021 RPS Procurement Plans (March 30, 2021); D.21-01-005 directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); Ruling on Staff proposal aligning RPS/IRP filings (September 18, 2020); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

IRP Rulemaking

On October 11, 2021, parties filed reply comments in response to party comments on the August 17, 2021 ALJ Ruling on a proposed Preferred System Plan. VCE and other LSEs made compliance filings by the October 15, 2021 deadline in response to the September 23, 2021, ALJ Ruling directing LSEs to formally file updated IRP information in the docket that had previously been informally provided to the Energy Division. On October 21, 2021, and October 28, 2021, parties filed comments and reply comments, respectively, in response to an October 13, 2021, Ruling that requested comments on natural gas issues. On October 26, 2021, California Community Power, of which VCE is a member, issued a Request for Offers for up to 200 MW of Firm Clean Resources (i.e., geothermal or biomass) with deliveries beginning no later than June 1, 2026.

- **Background**: On September 1, 2020, LSEs including VCE filed their 2020 IRPs, which included updates on each LSE's progress towards completing additional system RA procurement ordered for the 2021-2023 years under D.19-11-016.

  The September 24, 2020 Scoping Memo and Ruling clarified that the issues planned to be resolved in this proceeding are organized into the following tracks:

  - General IRP oversight issues: This track will consider moving from a two-year to a three-year IRP cycle, IRP filing requirements, and interagency work implementing SB 100.
  - Procurement track: D.21-06-035 establishing the 11,500 MW by 2026 procurement mandate resolved many of the procurement track issues. However, the CPUC will conduct additional quantitative and qualitative analysis in the next few months to help inform the preferred system portfolio (PSP) decision, expected by the end of 2021, where it may consider additional capacity procurement requirements, including the possibility of additional fossil fuel procurement.
  - Preferred System Portfolio Development: The CPUC has aggregated LSE portfolios, analyzed the aggregate portfolio, and proposed a PSP. The next step after party comments and reply comments will be the issuance of a proposed decision and final decision adopting a PSP.
  - TPP: *Completed*. D.21-02-028 transmitted portfolios to the CAISO for use in its TPP analysis.
  - Reference System Portfolio Development: To the extent that a new round of RSP analysis is conducted for the next IRP cycle, this proceeding will be the venue for developing and vetting the resource assumptions associated with that analysis in preparation for the next IRP cycle.

  D.20-12-044 established a backstop procurement process that would apply to LSEs that did not opt-out of self-procuring their capacity obligations under D.19-11-016. It requires LSEs to file bi-annual (due February 1 and August 1) updates on their procurement progress relative to the contractual and procurement milestones defined in the decision. After review of the compliance filings, CPUC Staff will bring a Resolution before the Commission specifying the amount of backstop procurement required for a particular IOU on behalf of each LSE for each procurement tranche (2021, 2022, and 2023).

  D.21-06-035 established a new procurement mandate of 11,500 MW of additional zero-emitting or RPS-eligible net qualifying capacity to be procured by 2026 by LSEs through long-term (10 or more years) contracts. It ordered that the resources from Diablo Canyon be replaced with at least

2,500 MW of zero-emitting resources. In addition, it specifies that 2,000 MW of the procurement mandate required for 2026 must be "long-lead-time" (LLT) resources, with half coming from long-duration storage and the other half from zero-emitting resources with an 80% or greater capacity factor, with the Decision pointing to geothermal and biomass as the resources best-suited to meet this category. VCE is permitted to use resources that were not online or in-development and contracted and approved by its Board as of June 30, 2020 to count towards its procurement requirements (i.e., contracts approved by the VCE Board and executed after June 30, 2020, can count towards VCE's procurement mandates). LSEs will ***not*** be given the option to opt out up front from providing their proportional share of the capacity required by D.21-06-035. The February 1, 2023 compliance filing will be the first check on the status of LLT resource procurement. VCE's new obligations and a description of the specific resource requirements for each subcategory of procurement are detailed in the following table.

Table: VCE New & Additional Procurement Obligations Under D.21-06-035

				2026 (Long-Lead Time Resources)		Diablo Replacement	
	2023	2024	2025	Long-Duration Storage	Zero-Emitting Generation Resources	Minimum zero-emitting capacity by 2025 *(subset of 2023, 2024, and 2025 columns)*	Total
VCE Obligation (September NQC MW)	8	23	6	4	4	10	44
Resource Requirements	Zero-emitting or RPS eligible	Zero-emitting or RPS eligible	Zero-emitting or RPS eligible	Must be able to discharge at maximum capacity over at least an eight-hour period from a single resource.	Zero-emitting resources or those that otherwise qualify as eligible under the RPS program and have at least an 80% capacity factor. Must be a generating resource, not storage, able to generate when needed, for as long as needed. Must not be use limited or weather dependent. May not have any on-site emissions, except if the resource otherwise qualifies under the RPS.	(1) Be from a generation resource, a generation resource paired with storage (physically or contractually), or a demand response resource; (2) Be available every day from 5 p.m. to 10 p.m. (the beginning of hour ending 1800 through the end of hour ending 2200), Pacific Time, at a minimum; and (3) Be able to deliver at least 5 megawatt-hours of energy during each of these daily periods for every megawatt of incremental capacity claimed.	

An August 17, 2021 Ruling provided a summary of analysis conducted by CPUC Staff to recommend key elements of the preferred system plan (PSP), including a preferred resource portfolio. The Ruling describes how and why LSEs' IRPs submitted in September 2020 are expected to fall short of meeting GHG and reliability targets, due to a collective insufficiency of planned new capacity. However, when incorporating the expected impacts of the procurement mandates in D.21-06-035 on mid-term reliability, the Ruling states that reliability and GHG goals are likely to be achieved. The Ruling recommends that the 38 MMT Core Portfolio be adopted by the CPUC as the PSP. This would be a more aggressive GHG target than the 46 MMT by 2030 target previously adopted.

- **Details**: The October 13, 2021 Ruling requested comments and recommendations in response to the CEC's Mid-Term Reliability Analysis Staff Report and a CPUC staff paper titled "Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning." The analyses could be used to support a CPUC decision allowing or requiring natural gas plant upgrades to meet reliability needs in the mid-term. The CEC Mid-Term Reliability Analysis covered reliability modeling for the years 2023 – 2026, questions associated with the growth of battery energy storage on the grid and the implications for reliability, and options for additional thermal resources. Actions the CPUC could take in response include procurement actions this year as part of consideration a Preferred System Plan (PSP), such as whether gas capacity upgrades at existing sites should be considered as eligible resources for the procurement requirements of D.21-06-035 (i.e., the decision creating a procurement mandate for 11,500 MW of new capacity). The CPUC staff paper found that allowing gas upgrades lowers CAISO system costs in all scenarios and concluded that gas upgrades appeared cost-effective for reliability needs starting in 2024, and in the near-term to meet a higher PRM in 2022 or 2023.

The October 26, 2021 RFO issued by CC Power could result in resource procurement that would allow VCE to meet its compliance obligation for additional clean firm resources under D.21-06-035.

- **Analysis**: The August 17, 2021 Ruling proposing a PSP would accelerate the build-out of clean energy resources by adopting a more aggressive GHG reduction target for the electricity sector over the coming decade. It also posed numerous questions that suggest the CPUC is considering other major changes to procurement mandates that could either result in additional or accelerated procurement requirements for VCE or the imposition of a non-bypassable charge, including on VCE customers, to recover the costs of additional procurement needed for reliability or policy reasons. The October 13, 2021 Ruling on natural gas issues suggests a future CPUC decision could could modify the 11,500 MW procurement mandate under D.21-06-035 to allow certain natural gas capacity upgrades at existing sites to be eligible.
- **Next Steps**: The schedule is as follows:
  - Procurement track: Potential changes to natural gas eligibility under D.21-06-035, and associated procurement actions by the CPUC, apparently will be considered as part of the PSP track (below). It is unclear at this time if other procurement-related issues will be addressed via the PSP decision or through separate CPUC decisions.
  - General IRP oversight issues: A Proposed Decision on the IRP cycle (e.g., possibly moving from every 2 years to a 3-year cycle) is anticipated to be issued soon.
  - Preferred System Portfolio Development: The issuance of a proposed decision, followed by opportunities for comments and reply comments, and the issuance of a final decision are anticipated next.
- **Additional Information**: Ruling requesting comments on natural gas issues (October 13, 2021); Ruling granting IRP confidentiality motions (September 23, 2021); Ruling proposing a PSP (August 17, 2021); Ruling extending procurement compliance filing deadline (July 10, 2021); D.21-06-035 establishing a 11,500 MW by 2026 procurement mandate (June 24, 2021); Ruling Setting August 1, 2021 Procurement Compliance Deadline (April 9, 2021); D.21-02-028 recommending portfolios for CAISO's 2021-2022 TPP (February 17, 2021); D.20-12-044 establishing a backstop procurement process (December 22, 2020); Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Ruling on IRP cycle and schedule (June 15, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

PG&E 2022 ERRA Forecast

On October 6, 2021, PG&E filed rebuttal testimony. On October 22, 2021, and November 1, 2021, respectively, parties filed opening and reply briefs.

- **Background**: Energy Resource and Recovery Account (ERRA) forecast proceedings establish the amount of the PCIA and other non-bypassable charges for the following year, as well as fuel and purchased power costs associated with serving bundled customers that utilities may recover in rates.

  On June 1, 2021, PG&E filed its 2022 ERRA Forecast application, requesting a 2022 ERRA forecast revenue requirement for ratesetting purposes of $4.736 billion. After accounting for $2.479 billion of Utility Owned Generation (UOG)-Related Costs and amounts related to capped 2020 departing load PCIA rates addressed in D.20-12-038, PG&E is requesting a revenue requirement request in this application of $2.263 billion.

PG&E preliminarily forecasts that in 2022 the system average bundled service customer rate will increase by 2.4%, the system average DA and CCA rate will decrease by 9.6%, and the departing load rate will increase by 1.7%. VCE's customers' PCIA rates will decrease, on average, by $0.01872/kWh (2017 PCIA Vintage). Consistent with D.21-05-030, PG&E has removed the capping and triggering mechanisms for PCIA rates in this 2022 ERRA Forecast Application. PCIA rates for the 2009 though 2022 customer vintages include PCIA base rates, formerly referred to as uncapped PCIA rates in the 2021 ERRA Forecast Application, plus PUBA rate adders for each vintage. Proposed 2022 PCIA rates, inclusive of the PUBA adder, are shown in the table below.

TABLE 20-4
PROPOSED POWER CHARGE INDIFFERENCE ADJUSTMENT RATES BY CLASS AND VINTAGE APPLICABLE TO POWER CHARGE INDIFFERENCE ADJUSTMENT -ELIGIBLE DEPARTING LOAD CUSTOMERS (WITH DWR FRANCHISE FEE)
($/KWH)

Line No.	Customer Class	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage
1	Residential	$0.01962	$0.02508	$0.02641	$0.02901	$0.02812	$0.02825	$0.02810	$0.02845	$0.02817	$0.02858	$0.02810	$0.02484	$0.03364	$0.03364
2	Small L&P	$0.01875	$0.02397	$0.02523	$0.02772	$0.02687	$0.02700	$0.02685	$0.02719	$0.02692	$0.02731	$0.02685	$0.02374	$0.03214	$0.03214
3	Medium L&P	$0.02022	$0.02585	$0.02721	$0.02990	$0.02897	$0.02912	$0.02896	$0.02932	$0.02903	$0.02945	$0.02896	$0.02560	$0.03467	$0.03467
4	B19/E19	$0.01880	$0.02403	$0.02530	$0.02780	$0.02694	$0.02707	$0.02692	$0.02727	$0.02699	$0.02739	$0.02693	$0.02380	$0.03224	$0.03224
5	Streetlights	$0.01563	$0.01998	$0.02103	$0.02311	$0.02240	$0.02250	$0.02238	$0.02266	$0.02244	$0.02276	$0.02238	$0.01979	$0.02679	$0.02679
6	Standby	$0.01409	$0.01801	$0.01896	$0.02083	$0.02019	$0.02028	$0.02017	$0.02043	$0.02022	$0.02052	$0.02018	$0.01784	$0.02415	$0.02415
7	Agriculture	$0.01777	$0.02271	$0.02391	$0.02627	$0.02546	$0.02558	$0.02544	$0.02576	$0.02550	$0.02587	$0.02544	$0.02249	$0.03046	$0.03046
8	B20/E20 T (Excluding Fl	$0.01607	$0.02053	$0.02162	$0.02375	$0.02302	$0.02313	$0.02300	$0.02329	$0.02306	$0.02340	$0.02301	$0.02034	$0.02754	$0.02754
9	B20/E20 P (Excluding F	$0.01721	$0.02200	$0.02316	$0.02545	$0.02466	$0.02478	$0.02464	$0.02496	$0.02471	$0.02507	$0.02465	$0.02179	$0.02950	$0.02950
10	B20/E20 S (Excluding Fl	$0.01794	$0.02294	$0.02415	$0.02653	$0.02571	$0.02584	$0.02569	$0.02602	$0.02576	$0.02613	$0.02570	$0.02272	$0.03076	$0.03076
11	BEV1	$0.01597	$0.02042	$0.02150	$0.02362	$0.02289	$0.02300	$0.02287	$0.02316	$0.02293	$0.02326	$0.02288	$0.02022	$0.02738	$0.02738
12	BEV2	$0.01865	$0.02384	$0.02510	$0.02758	$0.02673	$0.02686	$0.02671	$0.02705	$0.02677	$0.02717	$0.02671	$0.02361	$0.03198	$0.03198
13	System Average PCIA Rate by Vintage	$0.01886	$0.02411	$0.02539	$0.02789	$0.02704	$0.02717	$0.02702	$0.02736	$0.02709	$0.02748	$0.02703	$0.02391	$0.03231	$0.03231

- **Details**: Testimony of the Joint CCAs recommends, among other provisions:
    - PG&E should correct the allocation of the gain on sale of its San Francisco headquarters across the ERRA and PCIA vintages to be consistent with the allocation of other common costs included in the PCIA.
    - The 2022 Indifference Amount and 2021 year-end PABA balance should be reduced to remove the above-market cost of solar resources used to supply PG&E's GTSR and DAC-GT programs.
    - PG&E should be required to provide Reviewing Representatives access to confidential data used in prior ERRA Forecasts as part of the existing Master Data Request.
    - PG&E's proposed transfer of the 2021 year-end ERRA balancing account balance to the latest PABA vintage should again be approved as an interim measure until this issue is resolved in the PCIA rulemaking proceeding.
    - PG&E should correct a miscalculation of the RA Charge included in its GTSR and Enhanced Community Renewables rates.
    - PG&E should be required to identify in future ERRA proceedings transactions executed by PG&E as the Central Procurement Entity 22 for Local RA and the effect of CPE procurement on the Cost Allocation Mechanism and PCIA.
- **Analysis**: PG&E has agreed with the Joint CCAs on the SF headquarters allocation. It continues to fight against transparency in its rates, but then caved on providing the prior year's workpapers to the CCAs in each case in its Reply Brief. It also continues to undervalue the GTSR RA charge, which makes its 100% renewable program look more cost competitive than it actually is and creates a cost shift between bundled customers that participate in the program and those that do not. Lastly, PG&E continues to fight against parties being able to analyze its CPE transactions in a transparent manner.
- **Next Steps**: PG&E's update is due November 8, 2021, comments on the PG&E update are due November 18, 2021, a proposed decision will be issued December 1, 2021, and a final decision is anticipated on December 13, 2021.

- **Additional Information**: Scoping Memo and Ruling (August 11, 2021); Notice of Prehearing Conference (July 15, 2021); Application (June 1, 2021); Docket No. A.21-06-001.

PG&E's 2019 ERRA Compliance

Energy Division hosted a workshop on the IOU proposed methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events.

- **Background**: Phase 1 has been resolved. The September 7, 2021 Ruling consolidated the Phase 2 ERRA compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:
    - What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 PSPS events?
    - Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.
- **Details**: At the October 26, 2021, workshop hosted by Energy Division, the IOUs (PG&E, SCE, and SDG&E) made a joint presentation of their proposal for a methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events. CCA representatives pushed back that the IOUs had not considered unrealized revenues from utility-owned generation that had not been bid into the CAISO market. The ALJ requested the CCAs make a motion to clarify whether that issue is in scope in the proceeding.
- **Analysis**: Phase 2 of the proceeding is assessing whether PG&E should be required to return its revenue requirement associated with unrealized sales associated with its 2019 PSPS events, and the methodology and inputs for calculating such disallowance. VCE's customers could benefit from such a CPUC-determined disallowance, e.g., via a bill credit or reduced PG&E charges.
- **Next Steps**: IOU Phase 2 testimony is due November 5, 2021, Intervenor Phase 2 testimony is due January 17, 2022, IOU rebuttal testimony is due February 15, 2022, and a Joint Case Management Statement is due February 25, 2021.
- **Additional Information**: Ruling consolidating ERRA compliance proceedings (September 7, 2021); PG&E Application for Rehearing of D.21-07-013 (August 16, 2021); D.21-07-013 resolving Phase 1 (July 16, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

PCIA Rulemaking

On October 1, 2021, and October 8, 2021, respectively, parties filed comments and reply comments on the September 17, 2021, Ruling requesting comments on ERRA and PCIA issues. On October 19, 2021, PG&E requested to delay implementation of the line-item presentation of the PCIA on bundled customer bills from December 31, 2021, until October 1, 2023.

- **Background**: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity. Phase 2 relied primarily on a working group process to further develop a number of PCIA-related proposals. Three workgroups examined three issues: (1)

issues with the highest priority: Benchmark True-Up and Other Benchmarking Issues; (2) issues to be resolved in early 2020: Prepayment; and (3) issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction.

D.20-08-004, in response to the recommendations of Working Group 2, (1) adopted the consensus framework of PCIA prepayment agreements; (2) adopted the consensus guiding principles, except for one principle regarding partial payments; (3) adopted evaluation criteria for prepayment agreements; (4) did not adopt any proposed prepayment concepts; and (5) clarified that risk should be incorporated into the prepayment calculations by using mutually acceptable terms and conditions that adequately mitigate the risks identified by Working Group Two.

The Phase 2 Decision, D.21-05-030, addressed the recommendations of PCIA Working Group 3 and removed the cap and trigger for PCIA rate increases, authorized new Voluntary Allocation, Market Offer, and Request for Information processes for RPS contracts subject to the PCIA, and approved a process for increasing transparency of IOU RA resources. However, it did not provide unbundled customers proportional access to system and flexible RA products through the RA voluntary allocation and market offer process proposed by PCIA Working Group 3. Likewise, it declined to provide unbundled customers any access to GHG-Free energy on a permanent basis.

The CCA Parties' Application for Rehearing of D.21-05-030 challenges the Decision's rejection of the RA voluntary allocation and market offer and GHG-free energy allocation. It argues that D.21-05-030 violates Public Utilities Code Section 366.2(g), which guarantees CCA customers the full benefit of the resources for which they bear cost responsibility through the PCIA charge. While CCA customers pay for the RA and GHG-Free products in the PCIA portfolio, the Phase 2 Decision, provides only bundled customers preferential access to RA products and no access to GHG-Free energy on a long-term basis. The CCA Parties argue that since D.21-05-030 effectively requires unbundled customers to pay equally for benefits only bundled customers receive, the Phase 2 Decision also violates the Section 365.2 prohibition against cost-shifting among unbundled and bundled customers.

A Staff Proposal on which the August Ruling requested comments would move the Market Price Benchmark calculation date up by one month – from November 1 to October 1 – to allow for a "normal" proceeding schedule and enable flexibility in addressing last- minute issues. Staff's analysis found that the effects of changes in the forecast RPS and RA adders on PCIA rates are relatively small and concluded that the largest driver of changes to PCIA rates would be the energy index.

Details: The October 19, 2021, PG&E requested an extension of time to comply with Ordering Paragraph 2 of D.20-03-019, which requires PG&E to display a PCIA line item on bundled customer bills. PG&E requests an extension to comply with this requirement from December 31, 2021, to October 1, 2023. PG&E says this is necessary because it is undertaking a multi-year billing system modernization initiative that has required a freeze in any new structural rate changes and billing presentation to PG&E's Advanced Billing System through October 2022. After meeting with CCA, Direct Access, and Energy Division representatives, PG&E also committed to make several additional changes to the bill related to PCIA presentation and rate comparison and to conduct further meetings to discuss how the stakeholders' broader desires for bill presentment might be achieved more efficiently as a package, including showing PCIA as a line item on the back of the bill, within PG&E's billing system modernization initiative timeline. In addition to updating the PCIA definition, PG&E will make the following changes as an interim solution by Q2 2022 to help customers understand that the generation line items on bundled bills include a component for PCIA analogous to the PCIA line item on unbundled customers' bills:

- The definition on the back of the bill will also include a link to www.pge.com/cca which hosts the CCA rate comparison reports and also includes a side-by-side listing of the PCIA charge for bundled customers and unbundled customers by rate class.
- The PCIA component for bundled customers will be included in the CCA annual rate comparison mailer typically sent in July each year, subject to approval by the CPUC Public Advisor's Office.

  - A bill message on bundled customers' service agreement details section of their bill indicating the information regarding the PCIA component of generation and the link to www.pge.com/cca.

- **Analysis**: The issues on which the CPUC requested comments in the September Ruling impact CCAs' ability to gain access to confidential IOU data pertinent to the calculation and implementation of the PCIA, as well as the alignment of ERRA and PCIA proceedings. PG&E's requested extension of time would delay the line-item PCIA on bundled customer bills, but include interim changes such as providing in bills a link to PG&E's website that includes CCA rate comparisons and additional information on the PCIA.

- **Next Steps**: This proceeding remains open to consider (1) Phase 2 issues relating to ERRA proceedings and (2) whether GHG-Free resources are under-valued in the PCIA methodology, and if so, the appropriate way to address this problem.

  D.21-05-030 identified the following next steps:

  - **January 1, 2022**: PCIA cap is removed from rates.
  - **January 2022**: Once the 2021 RFIs are approved, the IOUs may request approval for Contract Assignments and Contract Modifications in response to the RFI by filing Tier 3 advice letters.
  - **February 2022**: After approval of the joint methodology advice letter, IOUs will inform LSEs of their potential Voluntary Allocation shares.
  - **May 2022**: IOUs and LSEs complete the process of determining interest in Allocation elections.
  - **June 2022**: Each IOU confirms Voluntary Allocations and propose Market Offers in their 2022 RPS Procurement Plans. LSEs request approval for Voluntary Allocations in their 2022 RPS Procurement Plans.

- **Additional Information**: Ruling requesting comments (September 17, 2021); Ruling providing Energy Division proposal (August 25, 2021); PG&E AL 6306-E (August 23, 2021); PG&E AL 5973-E-A (August 13, 2021); CalCCA Application for Rehearing of D.21-05-030 (June 23, 20210: D.21-05-030 on PCIA Cap and Portfolio Optimization (May 24, 2021); D.21-03-051 granting petition to modify D.17-08-026 (March 26, 2021); Amended Scoping Memo and Ruling (December 16, 2020); CalCCA/DACC/AReM Protest of PG&E AL 5973-E (November 2, 2020); PG&E AL 5973-E (October 12, 2020); CalCCA/DACC Response to Joint IOU AL on D.20-03-019 (September 21, 2020); Joint IOUs PFM of D.18-10-019 (August 7, 2020); D.20-08-004 on Working Group 2 PCIA Prepayment (August 6, 2020); D.20-06-032 denying PFM of D.18-07-009 (July 3, 2020); D.20-03-019 on departing load forecast and presentation of the PCIA (April 6, 2020); Ruling modifying procedural schedule for working group 3 (January 22, 2020); D.20-01-030 denying rehearing of D.18-10-019 as modified (January 21, 2020); D.19-10-001 (October 17, 2019); Phase 2 Scoping Memo and Ruling (February 1, 2019); D.18-10-019 Track 2 Decisions adopting the Alternate Proposed Decision (October 19, 2018); D.18-09-013 Track 1 Decision approving PG&E Settlement Agreement (September 20, 2018); Docket No. R.17-06-026.

PG&E 2020 ERRA Compliance

On October 15, 2021, parties filed a Settlement Agreement resolving disputed issues in this proceeding.

- **Background**: The annual ERRA Compliance proceeding reviews the utility's compliance with CPUC-approved standards for generation-procurement and cost recovery activity occurring in the preceding year, such as energy resource contract administration, least-cost dispatch, fuel procurement, and balancing account entries.

  PG&E is requesting that the CPUC find it complied with its Bundled Procurement Plan (BPP) in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, resource adequacy sales, and least-cost dispatch of electric generation resources for the 2020 calendar year. It also seeks a CPUC finding that it managed its utility-owned generation (UOG) facilities reasonably, although it recommends that CPUC review of outages at Diablo Canyon Power Plant related to the Unit 2 main generator be delayed to the 2021 ERRA Compliance review. Of significance to the PCIA, PG&E is requesting the CPUC find that entries in its Portfolio Allocation Balancing Account (PABA), which trues up the above-market forecast of generation resources recovered through the PCIA with actual recorded costs and revenues, are accurate.

PG&E's procurement costs recorded across the portfolio were $158.8 million higher than forecasted, allegedly due to higher-than-forecast RPS-eligible contracts, as offset by higher than forecast retained RPS and retained RA, as well as lower than forecast fuel costs for UOG facilities. Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity, RA Activity, Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, GHG Costs, and Miscellaneous Costs. PG&E has redacted as confidential its 2020 actual and forecast costs for these categories, so it is unclear from the public filing what the magnitude is regarding the difference between actual and forecast costs for each category.

The Scoping Memo and Ruling specifies the proceeding will be divided into two phases. Phase 1 will address whether PG&E (1) prudently administered and managed Utility-Owned Generation facilities and QF and non-QF contracts, (2) achieved least-cost dispatch of energy resources, (3) had reasonable, accurate, and appropriate ERRA and PABA entries, and (4) administered RA procurement and sales consistent with its Bundled Procurement Plan, among other issues. Phase 2 issues may be amended based on the outcome of Phase 2 of PG&E's 2019 ERRA compliance proceeding. The tentative list of issues include whether sales forecasting methods for adjusting revenue requirement under current decoupling policy should be adjusted to account for power not sold or purchased during a Public Safety Power Shutoff (PSPS) event in 2020, whether it is appropriate for PG&E to return the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2020, and the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2020 PSPS events.

In testimony, Joint CCAs recommended a number of accounting adjustments that would reduce PUBA balances by more than $14.3 million. They also recommend the CPUC acknowledge that PG&E's internal audit of its PABA concluded that the processes and controls governing PABA accounting are "Not Adequate," and that PG&E remedy the identified deficiencies. Furthermore, they recommend that the CPUC clarify that future procurement expenses incurred by PG&E acting as the Central Procurement Entity will be reviewable in ERRA Compliance proceedings, and that PG&E should demonstrate the effect of such procurement, if any, on the PABA and ERRA balancing accounts.

PG&E agreed in rebuttal testimony that the accounting for PCIA costs attributed to customers taking service on the GTSR tariff should be adjusted to correctly credit PABA for the 2019 and 2020 record periods, reducing the PABA balance by approximately $5 million. PG&E also agreed to present testimony in its 2021 ERRA Compliance proceeding addressing actions taken in response to the Internal Audit findings that PABA accounting process and controls were inadequate.

- **Details**: In the Settlement Agreement, PG&E agreed with the Joint CCAs' position to a disallowance of $247,500 associated with CAISO penalties for load meter data errors, late submission of Resource Adequacy and Supply Plans and missed deadlines for grid modeling data or telemetry communication for PG&E's utility owned generation and that any future sanctions for missed deadlines for grid modeling data or telemetry communication for PG&E's utility-owned generation will not be recovered from customers. Joint CCAs agreed that CAISO sanctions associated with Power Purchase Agreements (contracted generation) were caused by the counterparty and passed through to the counterparty and should not be disallowed.

PG&E agreed that entries to the PABA for costs associated with the Green Tariff Shared Renewables program should be reduced by $5 million for 2019 and 2020, as Joint CCAs had argued.

PG&E also agreed that certain issues should be in the scope of future ERRA proceedings, resolving the Joint CCA concern regarding its ability to review PG&E's accounting with respect to transactions with the CPE in future ERRA Compliance proceedings.

Finally, PG&E agreed to transfer from PABA to ERRA 2014 and 2017 Diablo Canyon Seismic Studies Balancing Account recorded costs, whereas the 2018 costs were retained in the PABA, which resolved the Joint CCAs concerns about that cost recovery.

- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022 and 2023.
- **Next Steps**: A PD is anticipated for Q1 2022.
- **Additional Information**: Joint Motion for Adoption of Settlement Agreement (October 15, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

Provider of Last Resort Rulemaking

On October 28, 2021, Golden State Power Cooperative filed a Motion to remove the state's electric cooperatives as respondents to the proceeding. A workshop was held on October 29, 2021, to review the operation and expectation of POLR service, registration, and financial security requirements.

- **Background**: A POLR is the utility or other entity that has the obligation to serve all customers (e.g., PG&E is currently the POLR in VCE's territory). In 2019 the Legislature passed SB 520, which defined POLR for the first time in statute, confirmed that each IOU is the POLR in its service territory, and directed the Commission to establish a framework to allow other entities to apply and become the POLR for a specific area (a "Designated POLR"). This rulemaking will implement SB 520.

  The Scoping Memo and Ruling describes the issues that are within scope in the proceeding and the procedural schedule going forward, although most of the procedural dates currently lack specificity. Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.
- **Details**: Golden State Power Cooperative argues in its Motion that the CPUC does not have authority over electric cooperative rate-setting, and as such, issues regarding POLR requirements, cost recovery, or cost allocation are not directly relevant to the electric cooperatives. Since the electric cooperatives are not POLRs and because they do not have CCAs or ESPs providing electricity in their service territories, Golden State Power Cooperative asserts the issues regarding the return of customers to the POLR are not germane to the electric cooperatives and they should be removed as respondents.
- **Analysis**: This proceeding could impact VCE in several ways. First, in establishing rules for existing POLRs, it will address POLR service requirements, cost allocation, and cost recovery issues should a CCA or other LSE discontinue supplying customers resulting in the need for the POLR to step in to serve those customers. Second, in setting the requirements and application process for another entity to be designated as the POLR, it could create a pathway for a CCA or other retail provider to elect to become a POLR for its service area. The preliminary questions

(Appendix B to the OIR) suggest these issues will include examining topics such as CCA financial security requirements, portfolio risk and hedging, CCA deregistration, CCA mergers, and CCA insolvency.

- **Next Steps**: A ruling will be issued in Q4 2021 or Q1 2022 with questions to parties to comment on. Opening and reply comments will be due in Q1 2022.
- **Additional Information**: Golden State Power Cooperative Motion to remove cooperatives as respondents (October 28, 2021); Scoping Memo and Ruling (September 16, 2021); Ruling scheduling prehearing conference (April 30, 2021); Order Instituting Rulemaking (March 25, 2021); Docket No. R.21-03-011.

Investigation into PG&E's Organization, Culture and Governance (Safety OII)

On October 25, 2021, CPUC President Batjer sent a letter to PG&E stating that its execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action.

- **Background**: On December 21, 2018, the CPUC issued a Scoping Memo opening the next phase of an ongoing investigation into whether PG&E's organizational culture and governance prioritize safety. This current phase of the proceeding is considering alternatives to current management and operational structures for providing electric and natural gas in Northern California.

  A July 2020 ALJ Ruling described the issues that are potentially still in scope for this proceeding, which include a broad array of issues identified in the December 21, 2018 Scoping Memo, as modified by D.20-05-053 approving PG&E's reorganization plan, plus the ongoing work of NorthStar, the consultant monitoring PG&E. However, the Ruling observed that "it is not clear as a practical matter how many of those issues can be or should be addressed at this time," given PG&E is now implementing its reorganization plan and has filed its application for regional restructuring. Party comments did not explicitly raise the issue of CCA proposals to purchase PG&E electric distribution assets.

  A September 4, 2020 Ruling determined that I.15-08-019 will remain open as a vehicle to monitor the progress of PG&E in improving its safety culture, and to address any relevant issues that arise, with the consultant NorthStar continuing in its monitoring role of PG&E. The Ruling declined to close the proceeding but also declined to move forward with CCAs' consideration of whether PG&E's holding company structure should be revoked and whether PG&E should be a "wires-only company," as well as developing a plan for service if PG&E's CPCN is revoked in the future.

  In April 2021, the CPUC issued Resolution M-4852, placing PG&E into the first of six steps of the Enhanced Oversight and Enforcement process. This six-step process could ultimately result in a revocation of PG&E's certificate of public convenience and necessity if it fails to take sufficient corrective actions. Resolution M-4852 found that PG&E made insufficient progress toward approved safety or risk-driven investments and is not sufficiently prioritizing its Enhanced Vegetation Management (EVM) based on risk. It found that PG&E is not doing the majority of EVM work – or even a significant portion of work – on the highest risk lines.

  On August 18, 2021, CPUC President Batjer sent a letter to PG&E stating that she has directed CPUC staff to investigate whether to advance PG&E further within the Enhanced Oversight and Enforcement process. President Batjer's letter to PG&E identified "a pattern of self-reported missed inspections and other self-reported safety incidents," concluding that "this pattern of deficiencies warrants the fact-finding review." PG&E self-reported missed inspections of hydroelectric substations, distribution poles, and transmission lines. PG&E also reported missing internal targets for enhanced vegetation management and failing to identify dry rot in distribution poles treated with Cellon coating. Many of these issues occurred in High Fire Threat District areas.

- **Details**: The October 25, 2021, letter from President Batjer to PG&E asserts that PG&E's "execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action to better support customers in the event of an outage." It finds that since PG&E initiated the Fast Trip setting practice on 11,500 miles of lines in High Fire Threat Districts in late July, it has caused over 500 unplanned power outages impacting over 560,000 customers. It goes on to say that these Fast Trip-caused outages occur with no notice and can last hours or days. The letter goes on to outline near-term and ongoing transparency and accountability actions, as well as cost tracking.
- **Analysis**: The October 25, 2021, letter indicates PG&E's issues with outages extend beyond its execution of PSPS events and include its implementation of Fast Trip. Unlike a PSPS event, by definition, Fast Trip settings do not allow for advance notice to customers of an outage. The letter directs PG&E to make a number of corrective actions and filings related to transparency and accountability.
- **Next Steps**: The proceeding remains open, but there is no procedural schedule at this time.
- **Additional Information**: Letter from President Batjer to PG&E on Fast Trip issues (October 25, 2021); Letter from President Batjer to PG&E (August 18, 2021); Resolution M-4852 (April 15, 2021); Letter from President Batjer to PG&E (November 24, 2020); Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

PG&E Regionalization Plan

No updates this month. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.

- **Background**: In D.20-05-051 approving PG&E's reorganization following bankruptcy, PG&E was directed to file a regionalization proposal (Docket No.19-09-016). On June 30, 2020, PG&E filed its regionalization proposal, which describes how it plans to reorganize operations into new regions. PG&E proposes to divide its service area into five new regions. PG&E will appoint a Regional Vice President by June 2021 to lead each region, along with Regional Safety Directors to lead its safety efforts in each region. The new regions would include five functional groups that report to the Regional Vice President encompassing various functions including: (1) Customer Field Operations, (2) Local Electric Maintenance and Construction, (3) Local Gas M&C, (4) Regional Planning and Coordination, and (5) Community and Customer Engagement. Other functions will remain centralized, such as electric and gas operations, risk management, enterprise health and safety, the majority of existing Customer Care and regulatory and external affairs, supply, power generation, human resources, finance, and general counsel.

  In August 2020, parties filed protests and responses to PG&E's application. Of note, South San Joaquin Irrigation District filed a Protest arguing that PG&E's regionalization effort should not create a moratorium or interfere with municipalization efforts. In addition, five CCAs filed responses or protests to PG&E's application, with MCE and EBCE filing protests and City of San Jose, City and County of San Francisco, and Pioneer Community Energy filing responses.

  In February 2021, PG&E submitted its updated regionalization proposal ("Updated Proposal"). In response to feedback, PG&E modified its five regions (renamed North Coast, North Valley & Sierra, Bay Area, South Bay & Central Coast, and Central Valley), including moving Yolo County from Region 1 to Region 2 (North Valley & Sierra), where it would be grouped with the following counties: Colusa, El Dorado, Glenn, Lassen, Nevada, Placer, Plumas, Sacramento, Shasta, Sierra, Solano, Sutter, Tehama, and Yuba. PG&E also provided more information on the new leadership positions that it is creating and its "Lean Operating System" implementation.

Currently, PG&E is in Phase 1 of 3 of its regionalization plan, which is focused on refining regional boundaries, establishing roles and governance for regional leadership, and recruiting and hiring for those positions. In Phase 2 (second half of 2021 through 2022), PG&E will establish and implement the regional boundaries and provide the resources and staffing to support it. In Phase 3 (2023 and after), PG&E will continue to reassess, refine and collaborate with other functional groups to improve efficiencies, safety, reliability and customer service.

On August 31, 2021, PG&E, the California Farm Bureau Federation, the California Large Energy Consumers Association, the Center for Accessible Technology, the Coalition of California Utility Employees, the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), the Small Business Utility Advocates, and William B. Abrams filed a motion for approval of their settlement agreement ("Multi-Party Settlement Agreement). A separate settlement agreement is between the South San Joaquin Irrigation District and PG&E. The Multi-Party Settlement Agreement includes a framework within which PG&E will facilitate a stakeholder engagement process for parties to the Multi-Party Settlement Agreement to provide updates and a non-binding forum for input for stakeholders. The proposed settlement would restrict participation in the Regionalization Stakeholder Group to parties or others who agree to the scope, procedures and protocols of the Regionalization Stakeholder group as outlined in the settlement. PG&E will host two public workshops in 2022 and for each year until the completion of Phase III or its regionalization implementation to provide updates to the public about its regionalization implementation progress.

In the separate PG&E/SSJID Settlement Agreement, PG&E clarified and confirmed that its implementation of regionalization as managed by its Regionalization Program Management Office will not include any work to oppose SSJID's municipalization efforts. However, SSJID also acknowledged that PG&E may continue to respond to SSJID's municipalization efforts in other forums and proceedings separate from the regionalization proceeding and/or implementation of the Updated Regionalization Proposal.

- **Details**: VCE filed comments on the settlement jointly with Pioneer Community Energy that were critical of PG&E's Updated Proposal and the settlement. VCE and Pioneer recommended that the CPUC reject the settlement and require changes to PG&E's Updated Proposal, including alignment with the boundaries of regional councils of governments ("COGs") and requirements to coordinate with COGs, the development of metrics to measure PG&E's progress on key safety and customer relations issues, greater coordination between PG&E and CCAs, and improvements to the Regionalization Stakeholder Group to expand its access and efficacy.
- **Analysis**: The implications of PG&E's regionalization plan on CCA operations, customers, and costs are largely unclear based on the information presented in PG&E's application and updated application. PG&E's regionalization plan could impact PG&E's responsiveness and management of local government relations and local and regional issues, such as safety, that directly impact VCE customers. It could also impact municipalization efforts, although the pending SSJID settlement agreement stated that PG&E's regionalization efforts will not be in opposition to SSJID's municipalization. As part of Region 2, VCE would be grouped with several northern counties in central and eastern California.
- **Next Steps**: A Proposed Decision will be issued next.
- **Additional Information**: Joint Motion for approval of Settlement Agreements (August 31, 2021); Ruling granting schedule modification (August 20, 2021); Ruling denying evidentiary hearing (July 28, 2021); PG&E Joint Case Management Statement (July 20, 2021); Amended Scoping Memo and Ruling (June 29, 2021); PG&E Updated Regionalization Proposal (February 26, 2021); Ruling modifying procedural schedule (December 23, 2020); Scoping Memo and Ruling (October 2, 2020); Application (June 30, 2020); A.20-06-011.

Direct Access Rulemaking

No updates this month. On August 13, 2021, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.

- **Background**: In Phase 1 of this proceeding, the CPUC allocated the additional 4,000 GWh of Direct Access load to non-residential customers required by SB 237 (2018, Hertzberg) among the three IOU territories with implementation to begin January 1, 2021.

  In Phase 2, the CPUC issued D.21-06-033 recommending against any further Direct Access expansion at this time based primarily on a concern that doing so "would present an unacceptable risk to the state's long-term reliability goals." It observed that after considering recent reliability events (i.e., the summer 2020 heat storm and resulting rolling blackouts in California and February 2021 outage event and skyrocketing electricity prices in Texas) and IRP forecasts for additional generation, expanded direct access would result in further system fragmentation that raises serious electric system reliability concerns. Further portions of the Decision:

  - Observed that Direct Access providers do not have a track record of relying on long-term contracts to meet their energy needs, which could impede the development of new, needed resources.
  - Noted that allowing expansion could undermine the long-term contracts that LSEs such as CCAs have already entered (i.e., due to load migration) and make it difficult for them to enter new contracts.
  - Stated that currently, the CPUC is not able to ensure that Direct Access expansion would not increase GHG emissions and other pollutants when compared to retaining the current cap, as Direct Access providers have historically relied primarily on unspecified power and lead to a net decline in clean energy procurement.

- **Details**: In their July Application for Rehearing, parties including the Alliance for Retail Energy Markets and the Direct Access Customer Coalition argued that:

  - The CPUC broke the law and abused its discretion when it disregarded the express duties imposed on it by SB 237.
  - D.21-06-033 ignored the substantial evidence in the record as it pertains to: (1) concerns about electric service provider (ESP) procurement performance and (2) the alleged threat to reliability posed by load migration due to an expansion of Direct Access is inaccurate and discriminatory.
  - D.21-06-033 discriminates against non-residential customers and the ESPs that wish to serve them, thereby violating the dormant Commerce Clause of the US Constitution.
  - D.21-06-033 relied on "misrepresentations of facts and speculations."

  CalCCA's August response argued that:

  - The CPUC's interpretation of the statute was consistent with its plain language and legislative history.
  - The Decision is supported by the findings required by statute and is also adequately supported by findings based on the entire administrative record.
  - The dormant Commerce Clause argument fails because the Decision applies equally to both in-state and out-of-state ESPs, and therefore does not unfairly discriminate against out-of-state interests.
  - The argument that the Decision discriminates against both ESPs and their customers and therefore violates their Equal Protection rights fails the "rational basis" test in that the

Decision is based on the findings regarding electric grid reliability and environmental concerns.

- **Analysis**: This proceeding determined the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California. D.21-06-033 recommending against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.
- **Next Steps**: The only remaining item to be addressed in this proceeding is the Application for Rehearing.
- **Additional Information**: CalCCA Response to Application for Rehearing (August 13, 2021); Application for Rehearing of D.21-06-033 (July 29, 2021); D.21-06-033 recommending against direct access expansion (approved June 24, 2021); Ruling and Staff Report (September 28, 2020); Amended Scoping Memo and Ruling adding issues and a schedule for Phase 2 (December 19, 2019); Docket No. R.19-03-009; *see also* SB 237.

RA Rulemaking (2019-2020)

No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.

- **Background**: This proceeding had three tracks, which have now concluded. Track 1 addressed 2019 local and flexible RA capacity obligations and several near-term refinements to the RA program. D.19-10-020 purported to affirm existing RA rules regarding imports, but adopted a distinction in the import RA compliance requirements for resource-specific and non-resource specific contracts and required, for the first time, that non-resource-specific resources self-schedule (i.e., bid as a price taker) in the CAISO energy market.

  In Track 2, the CPUC previously adopted multi-year Local RA requirements and initially declined to adopt a central buyer mechanism (D.19-02-022 issued March 4, 2019).

  The second Track 2 Decision, D.20-06-002, adopted implementation details for the central procurement of multi-year local RA procurement to begin for the 2023 compliance year in the PG&E and SCE (but not SDG&E) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The Decision rejected a settlement agreement between CalCCA and seven other parties that would have created a residual central buyer structure (and did not specify the identity of the central buyer) and a multi-year requirements for system and flexible RA. Under D.20-06-002, if an LSE procures its own local resource, it may (1) sell the capacity to the CPE, (2) utilize the resource for its own system and flexible RA needs (but not for local RA), or (3) voluntarily show the resource to meet its own system and flexible RA needs, and reduce the amount of local RA the CPE will need to procure for the amount of time the LSE has agreed to show the resource. Under option (3), by showing the resource to the CPE, the LSE does not receive one-for-one credit for shown local resources. A competitive solicitation (RFO) process will be used by the CPEs to procure RA products. Costs incurred by the CPE will be allocated ex post based on load share, using the CAM mechanism. D.20-06-002 also established a Working Group (co-led by CalCCA) to address: (a) the development of an local capacity requirements reduction crediting mechanism, (b) existing local capacity resource contracts (including gas), and (c) incorporating qualitative and possible quantitative criteria into the RFO evaluation process to ensure that gas resources are not selected based only on modest cost differences.

  In Track 3, D.19-06-026 adopted CAISO's recommended 2020-2022 Local Capacity Requirements and CAISO's 2020 Flexible Capacity Requirements and made no changes to the System capacity requirements. It established an IOU load data sharing requirement, whereby each non-IOU LSE (e.g., CCAs) will annually request data by January 15 and the IOU will be required to provide it by March 1. It also adopted a "Binding Load Forecast" process such that an

LSE's initial load forecast (with CEC load migration and plausibility adjustments based on certain threshold amounts and revisions taken into account) becoming a binding obligation of that LSE, regardless of additional changes in an LSE's implementation to new customers.

On October 30, 2019, CalCCA filed a PFM of D.19-06-026, seeking the creation of an RA waiver process in 2020 for system and flexible RA obligations.

Details: The only two remaining items to be addressed in this proceeding are two applications for rehearing filed by Western Power Trading Forum (WPTF). First, on July 17, 2020, WPTF filed an Application for Rehearing of D.20-06-002, the Track 2 Decision creating a multi-year central procurement regime for local RA capacity. It requested rehearing and reconsideration of the rejected settlement agreement between WPTF, CalCCA, and other parties, arguing that D.20-06-002 will discourage the procurement of local resources by individual LSEs, discriminates against natural gas resources while increasing the need for CAISO backstop procurement, may undermine reliability by making it more difficult to integrate renewables with the larger western grid, and creates a "sale for resale" procurement construct that could place it under FERC's jurisdiction as a wholesale, rather than a retail, transaction.

Second, on August 5, 2020, WPTF filed an Application for Rehearing of D.20-06-028 with respect to the self-scheduling requirements for non-resource specific RA imports.

- **Analysis**: D.20-06-002 established a central procurement entity and mostly resolved the central buyer issues, although several details are being refined through a Working Group. Moving to a central procurement entity beginning for the 2023 RA compliance year will impact VCE's local RA procurement and compliance, including affecting VCE's three-year local RA requirements as part of the transition to the central procurement framework. Eventually, it will eliminate the need for monthly local RA showings and associated penalties and/or waiver requests from individual LSEs, but it also eliminates VCE's autonomy with regard to local RA procurement and places it in the hands of PG&E.

  The Track 1 Decision on RA imports most directly impacted LSEs relying on RA imports to meet their RA obligations by increasing the difficulty of procuring such RA in the future.

- **Next Steps**: The only issues remaining to be addressed in this proceeding are WPTF's Applications for Rehearing. Remaining RA issues will be addressed in the successor RA rulemaking, R.19-11-009.

- **Additional Information**: D.20-09-003 denying PFMs filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF's Application for Rehearing of D.20-06-028 (August 5, 2020); WPTF's Application for Rehearing of D.20-06-002 (July 17, 2020); D.20-06-028 on Track 1 RA Imports (approved June 25, 2020); D.20-06-002 establishing a central procurement mechanisms for local RA (June 17, 2020); D.20-03-016 granting limited rehearing of D.19-10-021 (March 12, 2020); D.20-01-004 on qualifying capacity value of hybrid resources (January 17, 2020); D.19-12-064 granting motion for stay of D.19-10-021 (December 23, 2019); D.19-10-021 affirming RA import rules (October 17, 2019); D.19-06-026 adopting local and flexible capacity requirements (July 5, 2019); Docket No. R.17-09-020.

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BTM	Behind the Meter
CAISO	California Independent System Operator

CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CTC	Competition Transition Charge
DA	Direct Access
DWR	California Department of Water Resources
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
EUS	Essential Usage Study
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
LSE	Load-Serving Entity
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
PD	Proposed Decision
PG&E	Pacific Gas & Electric
PFM	Petition for Modification
PCIA	Power Charge Indifference Adjustment
POLR	Provider of Last Resort
PSPS	Public Safety Power Shutoff
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act of 1978 (federal)
QC	Qualifying Capacity
QF	Qualifying Facility under PURPA
RA	Resource Adequacy
RDW	Rate Design Window
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard

SCE	Southern California Edison
SED	Safety and Enforcement Division (CPUC)
SDG&E	San Diego Gas & Electric
TCJA	Tax Cuts and Jobs Act of 2017
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)