

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: April 14, 2022

Please find attached Keyes & Fox's March 2022 Regulatory Memorandum dated April 6, 2022, 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 April 6, 2022.

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
Jason Hoyle, Principal Analyst, EQ Research, LLC

Subject: Regulatory Update

Date: April 6, 2022

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 March 2, 2022, PG&E and the Public Advocates Office (PAO) filed Responses to the Petition for Modification of D.21-12-015 filed by VCE, Polaris and TeMix (the Pilot Partners) relating to VCE’s dynamic rates pilot for agricultural irrigation pumping customers (Pilot). The Pilot Partners filed a Reply to those Responses on March 14, 2022. On March 3, 2022, PG&E filed a Reply to the Pilot Partners’ Protest of PG&E’s Advice Letter 6495-E. Authorization of VCE’s administrative expenses and reimbursement of vendor expenses remains pending before the Commission.
- **IRP Rulemaking:** On March 29, 2022, a Proposed Decision addressing cost allocation and recovery under the Modified Cost Allocation Mechanism (MCAM) was issued. The Final Decision is expected on or after May 5, 2022 and will be followed by Tier 2 Advice Letters from IOUs describing their implementation of the MCAM. VCE’s next IRP is due November 1, 2022.
- **RPS Rulemaking:** On March 10, 2022, the Joint IOUs filed a Motion requesting authorization to submit their proposed modifications to the Market Offer Process via Tier 3 Advice Letter on April 28, 2022. The proposed modifications would allow implementation of Market Offer REC transactions to coincide with the start of Voluntary Allocation deliveries and provide cost savings. VCE’s 2022 RPS Procurement Plan is due in late spring or summer (exact date TBD) and its 2021 RPS Compliance Report is due August 1, 2022.
- **PCIA Rulemaking:** On April 4, 2022, PG&E submitted Tier 2 advice letter proposing its pro forma Market Offer Contract, and requested proposed contract become effective on May 4, 2022, with protests/responses due April 25, 2022. On February 28, 2022, PG&E submitted Tier 2 advice letter proposing its pro forma Voluntary Allocation Contract and providing an updated timeline.

Additionally, on March 8, 2022, Rulemaking 17-06-026 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds.

- **NEW PG&E 2021 ERRR Compliance:** PG&E filed its 2021 ERRR Compliance application on February 28, 2022, in which it requests the CPUC find that the company complied with its CPUC-approved Bundled Procurement Plan, reasonably managed utility-owned generation facilities, and made other reasonable expenditures and accounting entries consistent with CPUC directives.
- **PG&E Phase 2 GRC:** The single carryover issue of material fact about the Marginal Generation Capacity Cost (MGCC) Property Tax Adder was resolved with issuance of a Final Decision adopting the Joint Stipulation on March 18, 2022. PG&E's MGCC Report was filed March 17, 2022, and PG&E filed its non-NEM export compensation proposal for BEV on March 24, 2022.
- **PG&E Phase 1 GRC:** PG&E filed an Amended Application and submitted supplemental testimony on wildfire mitigation programs in March 2022. A March 10 ALJ Ruling denied the Motion to Shorten Time filed by TURN, PG&E, and PAO, and suspended the March 30, 2022, deadline for intervenor testimony pending a ruling on their February 16, 2022, Motion to Modify the Schedule. PG&E filed its recorded expense and capital cost data for 2021 on March 9, 2022. Public Participation Hearings were held on three days during March 2022 regarding the February 2022 joint report, submitted by PG&E and Caltrain, on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco.
- **RA Rulemaking (2023-2024):** On March 18, 2022, the CPUC issued a Decision on Phase 1 of Implementation Track Modifications that made several changes to the CPE, including changes encouraging LSEs to self-show resources and modifying the timeline of CPE activities. This Decision concludes Phase 1 of the Implementation Track Modifications.
- **RA Rulemaking (2021-2022):** On March 18, 2022, the CPUC issued a Proposed Decision that would deny OhmConnect's September 2021 Petition for Modification of D.20-06-031 to increase the demand response Maximum Cumulative Capacity limit of 8.3% to 11.3%.
- **PG&E 2020 ERRR Compliance:** On March 16, 2022, the CPUC issued a Proposed Decision for Phase 1 in which the Settlement Agreement filed by the parties on October 15, 2021, was found to be reasonable and therefore resolves all the disputed issues in this proceeding. Phase 2 of the proceeding, which remains open, will address issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.
- **Provider of Last Resort Rulemaking:** Comments on the March 7, 2022, workshop to discuss the proposed framework for considering the issues and recommendations resulting from the previous Phase 1 workshop were filed March 28, 2022.
- **RA Rulemaking (2019-2020):** No updates this month. Rulemaking is effectively closed except for one outstanding application for rehearing that was filed in August 2020.
- **Utility Safety Culture Assessments:** A telephonic Prehearing Conference was held on March 30, 2022, to determine the parties, scope, schedule of the proceeding, and other procedural matters.

- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** No updates this month. The CPUC issued D.21-12-006 adopting a Wildfire Fund NBC of \$0.00652/kWh for January 1, 2022, through December 31, 2022.
- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month except to note that on March 7, 2022, Investigation 15-08-019 was reassigned from President Marybel Batjer to Commissioner John R.D. Reynolds.
- **PG&E Regionalization Plan:** No updates this month. The statutory deadline for a final decision was extended to June 30, 2022, in an order issued December 16, 2021.
- **PG&E 2022 ERRA Forecast:** No updates this month. On February 11, 2022, the CPUC issued D.22-02-002, resolving all issues and closing the proceeding. The final system average PCIA rate for the 2017 vintage is \$0.01897/kWh.
- **PG&E 2019 ERRA Compliance:** No update this month except to note that Opening Briefs are due May 6, 2022. On March 23, 2022, consolidated Application (A.) 20-02-009, A.20-04-002 and A.20-06-001 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds.
- **Direct Access Rulemaking:** On March 1, 2022, Rulemaking 19-03-009 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds. In August 2021, CalCCA filed a response to a July 2021 application for rehearing filed by a coalition of parties supporting expansion of Direct Access in which the coalition of parties challenged a June CPUC decision recommending against any re-opening of Direct Access. This proceeding is otherwise closed.

Ensuring Summer 2021 Reliability

On March 2, 2022, PG&E and the Public Advocates Office (PAO) filed Responses to the Petition for Modification of D.21-12-015 filed by VCE, Polaris and TeMix (the Pilot Partners) relating to VCE's dynamic rates pilot for agricultural irrigation pumping customers (Pilot). The Pilot Partners filed a Reply to those Responses on March 14, 2022. On March 3, 2022, PG&E filed a Reply to the Pilot Partners' Protest of PG&E's Advice Letter 6495-E.

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, adopts modifications and expansions to the Critical Peak Pricing (CPP) program, and established an emergency load reduction program.

D.21-12-015 approved VCE's dynamic rate Pilot for three years (2022-2024) and directed that it start no later than May 1, 2022. VCE's Pilot will test whether agricultural irrigation pumping customers, which consume on average 18% of VCE's total annual load, can shift load to more optimal times of the day, thereby saving money, reducing burden to the grid and reducing GHG impacts. Customers

participating in VCE's Pilot will receive a "shadow bill." PG&E will continue to 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 customer's usage under the otherwise applicable tariff. The Pilot scale will be limited to 5 MW of peak load. PG&E will 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. D.21-12-015 authorized new funding of \$3.25 million for the pumping automation technology, pricing platform and vendor fees and PG&E's administration of the three-year Pilot.

On January 5, 2022, VCE submitted Advice Letter 11-E in accordance with D.21-12-015. On January 25, 2022, PG&E protested VCE's Advice Letter, to which VCE replied on January 31, 2022.

On January 31, 2022, the Pilot Partners filed a Petition for Modification (PFM) of D.21-12-015 to increase the budget for this Pilot to cover VCE's administrative costs, and the Pilot Partners also filed a Motion to Shorten Time for comments on the PFM as well as on the Commission's proposed decision resolving the PFM. PAO filed a Response to the Pilot Partners' Motion to Shorten Time, on February 9, 2022, to which the Pilot Partners replied on February 18, 2022.

On February 4, 2022, PG&E submitted Advice Letter 6495-E, which the Pilot Partners Protested on February 24, 2022. The Pilot Partners objected to the pricing methodology proposed by PG&E, on the grounds that it is inconsistent with the UNIDE framework because the differentials between peak and off-peak are too small to effectively test the impacts of dynamic pricing. The Pilot Partners objected to PG&E's attempt to establish various participation rules for the Pilot, including determining eligibility for various types of net energy metering (NEM) customers and other participation requirements.

D.21-12-015 also creates 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). It requires all incremental resources procured as a result of this proceeding to be available during the net peak. It adopted numerous additional demand-side and supply-side changes aimed at ensuring sufficient resource availability to meet the summer net peak load.

Details: The PAO's Response to the PFM opposed to the Pilot Partners' request for an increased budget. PG&E's Response to the PFM did not oppose VCE's request for additional funding to cover administrative costs, but stated that PG&E would not release any funds to enable VCE to pay its vendors until the Commission issued a decision resolving the PFM, asserted that VCE be required to prepare semiannual Demand Response Emerging Technologies Reports (DRET) with numerous elements, and asserted numerous PG&E management responsibilities for the Pilot to be reflected in contracts with TeMix and VCE. PG&E's Reply to the Pilot Partners' Protest to Advice Letter 6495-E, submitted on February 4, 2022, asserted that PG&E would file a supplement to its advice letter to revise the delivery component of the Pilot rate, but reiterated that it would not enter into a contract with nor release reimbursement of expenses to VCE prior to the Commission's decision on the PFM.

On March 14, 2022, the Pilot Partners filed a Reply to the March 2 Responses of PG&E and the PAO to the PFM, requesting the Commission to direct PG&E to release at least \$1,197,118 in previously authorized funding to enable the Pilot to launch by May 1, 2022, and authorization of VCE's administrative costs, including DRET reporting, if required, and asserting a narrower role for PG&E in the Pilot administration.

Analysis: VCE is seeking approval and clarification of its advice letter and PFM to facilitate implementation of the Pilot, authorize reimbursement of VCE's administrative expenses as well as the release of about \$1.197 million to cover vendor expenses to-date and enable the Pilot to begin on May 1, 2022. PG&E was resistant to the authorization of VCE's Pilot in its comments to the Commission, and its actions since the Pilot was approved have had the impact of delaying Pilot implementation and hampering VCE's ability to pay its vendors. In its advice letter and other filings,

PG&E has asserted control over various elements of the Pilot that were not authorized by the Commission and the utility has not yet revised its proposed design for the delivery component of the Pilot rate.

Next Steps: The Commission's Energy Division has yet to resolve VCE's Advice Letter 11-E, PG&E's Advice Letter 6495-E, the PFM, or the Motion to Shorten Time. Absent a Commission ruling on the Pilot Partners' Motion to Shorten Time, a Commission Decision on the PFM is expected no earlier than April 21, 2022. D.21-12-015 requires that the Pilot launch by May 1, 2022.

Additional Information: VCE, Polaris, and TeMix [Reply](#) to PAO & PG&E Responses (March 14, 2022); PAO [Response](#) to VCE, Polaris, and TeMix Reply (March 2, 2022); PG&E [Response](#) to VCE, Polaris, and TeMix Reply (March 2, 2022); VCE, Polaris, and TeMix [Protest](#) of PG&E [AL 6495-E](#) (February 24, 2022); VCE, Polaris, and TeMix [Reply](#) to PAO Response (February 18, 2022); PAO [Response](#) to Motion to Shorten Time (February 9, 2022); PG&E [AL 6495-E](#) (February 4, 2022) and [Substitute Sheets](#) for AL 6495-E (March 29, 2022); PG&E [AL 6496-E](#) on Emergency Load Reduction Program Pilot (February 4, 2022); VCE [Reply](#) to PG&E Protest of VCE AL 11-E (January 31, 2022); VCE, TeMix and Polaris [Petition for Modification](#) (January 31, 2022); [Motion](#) to Shorten Time (January 31, 2022); PG&E [Protest](#) of VCE AL 11-E (January 25, 2021); [D.21-12-069](#) correcting errors in D.21-12-014 (December 27, 2021); [D.21-12-015](#) (December 6, 2021); [D.21-09-045](#) denying rehearing of D.21-03-056 (September 23, 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); [Order Instituting Rulemaking](#) (November 20, 2020); Docket No. [R.20-11-003](#).

IRP Rulemaking

On March 29, 2022, a Proposed Decision addressing cost allocation and recovery under the Modified Cost Allocation Mechanism (MCAM) was issued. The Final Decision is expected on or after May 5, 2022 and will be followed by Tier 2 Advice Letters from IOUs describing their implementation of the MCAM. VCE's next IRP is due November 1, 2022.

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, procurement track, Preferred System Portfolio development, the Transmission Planning Process, and Reference System Portfolio Development.

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.

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 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 (e.g., geothermal and biomass). 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 obligations** are 8 MW by 2023, 23 MW by 2024, 6 MW by 2025, 4 MW of long-duration storage and 4 MW of zero-emitting resources by 2026. In addition, 10 MW out of its 2023-2025 procurement requirements must be met through zero-emitting generating capacity that is available 5-10pm daily.

D.22-02-004 adopted a 2021 Preferred System Plan (PSP and certified VCE's 2020 IRP. VCE's next IRP is due November 1, 2022. The 2021 PSP is a statewide resource portfolio that meets a statewide 38 MMT GHG target for the electric sector in 2030. It is derived from an aggregation of individual LSE IRPs with adjustments to extend the timeframe beyond 2030 to 2032 for transmission planning purposes and to add the resources required in D.21-06-035 for mid-term reliability (MTR) purposes. The decision recommends that CAISO use the 38 MMT PSP portfolio as both the reliability base case and the policy-driven base case for study in its 2022-2023 Transmission Planning Process, which is a more aggressive GHG reduction portfolio than the 46 MMT portfolio used in 2020 IRPs. D.22-02-004 also results in the following new resource build by 2032, by technology: Gas: 0 MW; Biomass: 134 MW; Geothermal: 1,160 MW; Wind: 3,531 MW; Wind (New Transmission): 1,500 MW; Offshore Wind: 1,708 MW; Utility-Scale Solar: 17,506 MW; Battery Storage: 13,571 MW; Long-duration Storage: 1,000 MW; Load Shed DR: 441 MW.

Details: A Proposed Decision on the Modified Cost Allocation Mechanism (MCAM) was issued on March 29, 2022, that addresses allocation and recovery of net costs of electric resource procurement for opt-out LSEs (i.e., those LSEs who elected not to self-procure) and backstop procurement obligations.

The Proposed Decision addresses the issue raised by CalCCA (May 14, 2022 Petition for Modification of D.19-11-016) of whether the non-bypassable charge should appear on retail customers' bills or be directly billed to the LSE. The PD would not adopt CalCCA's proposal for the direct billing of the full MCAM costs from the IOU to the non-IOU LSE, and instead cites the Public Utilities Code's express direction that these costs be allocated "on a fully nonbypassable basis" to "customers" (Section 365.1(c)(2)(i)-(iii)).

The PD also addresses how the costs of backstop procurement of associated with D.19-11-016 and D.21-06-035 will be allocated to customers. Due to the short time frame for such procurement, the IOU should either choose a lower NPV bid from an existing solicitation or conduct an entirely new solicitation to procure backstop capacity, depending on the status and quality of existing bids and other market factors. If the IOU chooses the new solicitation option, then all costs will be attributable to the LSE whose procurement was deficient. If a bid from an existing solicitation is selected, then the IOU's administrative costs will be pro-rated between bundled and Deficient LSE customers while the contract costs for the backstop procurement will be fully allocated to the customers of the Deficient LSE. If the PD is approved, customers of the Deficient LSE would pay the above-market costs of the capacity through a non-bypassable charge while the backstop LSE's customers pay their LSE directly for the market price of the capacity and RPS RECs.

Analysis: The Proposed Decision regarding the MCAM would clarify that procurement costs will only be recovered from bundled service customers, Opt-Out LSE customers, and potentially Deficient LSEs rather than all customers in an IOU's service territory. If approved, cost recovery under MCAM will occur through a non-bypassable charge on retail customers' bills. Resource Adequacy benefits would also be allocated on the same basis as costs for purposes of the MCAM. Additionally, if the PD is approved, an LSE may acquire unbundled RECs but the transfer of RECs to LSEs must be accompanied by a forward sale of associated energy.

Next Steps: A Final Decision on the MCAM is expected on or after May 5, 2022, after which the IOUs will file a Tier 2 Advice Letter to implement the MCAM no more than 60 days following the Final Decision. VCE's next IRP is November 1, 2022. The CPUC will issue a Ruling by June 15, 2022, providing additional direction and detail on the requirements for LSE 2022 IRPs.

Additional Information: [Proposed Decision](#) on the Modified Cost Allocation Mechanism (March 29, 2022); [D.22-02-004](#) adopting 2021 Preferred System Plan (December 22, 2021); CCA [Motion](#) for Clarification (December 13, 2021); [D.21-06-035](#) establishing a 11,500 MW by 2026 procurement mandate (June 24, 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); [Order Instituting Rulemaking](#) (May 14, 2020); Docket No. [R.20-05-003](#).

RPS Rulemaking

On March 10, 2022, the Joint IOUs filed a Motion requesting authorization to submit their proposed modifications to the Market Offer Process via Tier 3 Advice Letter on April 28, 2022. The proposed modifications would allow implementation of Market Offer REC transactions to coincide with the start of Voluntary Allocation deliveries and provide cost savings.

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

D.22-01-004 directed VCE to include in its Final 2021 RPS Procurement Plan due February 17, 2022, a discussion "explain[ing] how mid-term reliability procurement obligations impact RPS compliance requirements and how they are included in the quantitative assessment" and update its Project Development Status section to provide additional narrative description of project status. In addition to receiving praise for its sections on portfolio diversity and reliability, VCE is identified as falling under the category of having its current contracts forecasted to meet its 65% long-term contract requirement in contrast to numerous other CCAs and ESPs. D.22-01-004 declined a request by CCAs to allow party comments early in the process on the timing and structure of RPS Procurement Plan filings, finding that the CPUC "do[es] not expect any substantial new filing requirements" and that the requirements have been well established by now. D.22-01-004 also approved a request by several CCAs and directed Energy Division to set a process whereby they inform a retail seller that its Final RPS Plan met the expectations of the Commission.

A pending Joint Motion by IOUs dated December 8, 2021 requests that the CPUC (1) expand the scope of this proceeding to address whether RECs retain their original PCC classification upon allocation under the Voluntary Allocation process; (2) issue guidance on the issue of the PCC classification of allocated RECs before LSEs are required to decide whether to accept allocations on May 1, 2022; and (3) clarify that pro forma Allocation Contracts will be reviewed in early 2022 via Tier 2 advice letter and that only Allocation Contracts materially deviating from the pro forma would be subject to further review through a Tier 1 Advice Letter.

Details: The Joint IOUs March 10, 2022, Motion seeks authorization for review via Tier 3 Advice Letter submission of their proposed modifications to the Market Offer Process. The proposed modifications would allow implementation of Market Offer transactions on January 1, 2023, to coincide with delivery of Voluntary Allocations, thereby generating revenue from the sale of RECs and reducing above-market costs "to benefit bundled service and departing load customers by optimizing the IOU's PCIA portfolios."

In D.22-01-025, the CPUC found that Gexa, an ESP that is currently not serving any load, met its procurement quantity requirement for the Compliance Period 2014-2016 and retired sufficient RECs. The decision found, however, that by excluding certain non-modifiable standard terms and conditions in a RPS procurement contract with NextEra Energy Marketing, LLC, Gexa was out of compliance with the requirements in D.08-04-009, D.10-03-021, D.11-01-025, and D.13-11-024. The non-modifiable standard terms and conditions relate to transfer of RECs, tracking of RECs in WREGIS and compliance with applicable law. Gexa retroactively added the non-modifiable and certain modifiable standard terms and conditions to its contract after the Compliance Period had closed.

Despite this, the CPUC imposed a fine of \$352,500 for the period that the REC Agreement underlying Gexa's Compliance Report was out of compliance with the applicable RPS program rules.

Analysis: VCE has now met its 2021 RPS Procurement Plan requirements. D.22-01-025 provides another example of how the CPUC has strictly interpreted RPS compliance requirements and issued sizeable penalties in cases of non-compliance. The Commission refused to permit retroactive RPS procurement contract amendment to comply with the requirement to include the nonmodifiable terms and conditions. In addition, the Commission's finding that Gexa complied with the long-term contract requirement warned was limited to the decision, and provided "in the future, we shall not accept any long-term contract that fails to demonstrate the required term of at least ten years."

Next Steps: VCE's draft 2022 RPS Procurement Plan will be due in late spring or summer 2022 (exact date to be determined), and its RPS Compliance Report will be due August 1, 2022. R.18-07-003 is expected to close in September 2022, with a new proceeding to be opened to address RPS issues going forward.

If authorized, the Joint IOUs will seek review of the Market Offer Process through a Tier 3 Advice Letter submitted **April 28, 2022**.

Additional Information: [Joint Motion](#) by IOUs Concerning Review of Market Offer Process (March 10, 2022); [VCE's Final 2021 RPS Procurement Plan](#) (February 17, 2022); [D.22-01-025](#) fining Gexa for RPS non-compliance (February 1, 2022); [D.22-01-004](#) on draft 2021 RPS Procurement Plans (January 18, 2022); [D.21-12-032](#) modifying the ReMAT tariff (December 16, 2021); [D.21-11-029](#) amending RPS confidentiality rules (November 19, 2021); [Petition for Modification](#) of D.20-10-005 on ReMAT pricing (October 8, 2021); [Ruling](#) aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26, 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](#).

PCIA Rulemaking

On April 4, 2022, PG&E submitted Tier 2 advice letter proposing its pro forma Market Offer Contract, and requested proposed contract become effective on **May 4, 2022**, with protests/responses due **April 25, 2022**. On February 28, 2022, PG&E submitted Tier 2 advice letter proposing its pro forma Voluntary Allocation Contract and providing an updated timeline. Additionally, on March 8, 2022, Rulemaking 17-06-026 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds.

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.

D.22-01-023 modified the PCIA market price benchmark release date to October 1 and the deadline for ERRA forecast applications to May 15 to enable the Commission to timely issue decisions on ERRA forecast applications. It adopted party proposals to establish a policy for disposition of the year-end balance in the ERRA account and to modify the calculation of the ERRA trigger point and threshold. It also adopted party proposals to support efficient party access to ERRA forecast proceeding data.

It kept the proceeding open to consider additional Phase 2 issues, including:

- Whether greenhouse gas-free resources are under-valued in the PCIA, and if so, whether to adopt an adder or allocation mechanism.
- Whether to adopt a new method to include long-term fixed-price transactions in calculating the Renewables Portfolio Standard adder.
- Whether to modify the calculation of the PCIA energy index market price benchmark.
- Whether to provide CCAs with access to confidential, market sensitive ERRA monthly reports information for the non-proceeding purpose of creating PCIA rate forecasts.

Details: PG&E submitted, in accordance with D.22-01-004, two proposed contracts for PCIA-eligible RPS resources: AL 6517-E (February 28, 2022) proposing a Voluntary Allocation Contract and AL 6551-E (April 4, 2022) proposing a Market Offer Contract.

AL 6517-E Voluntary Allocation Contract proposal

Since PG&E's Voluntary Allocation Contract is a confirmation to PG&E's Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement (Master Agreement), similar to the existing confirmation used in PG&E's bundled RPS energy sales, Voluntary Allocation participants will need a Master Agreement in place with PG&E prior to execution of the Voluntary Allocation Contract.

The terms of the proposed Voluntary Allocation Contract include:

- LSE's are allowed to make a short-term or long-term allocation election for a "slice" of the PCIA-eligible RPS portfolio in proportion to the LSE's vintaged allocation share, which is based on the LSE's forecasted annual load share.
- Allocation elections must be made in 10% increments of the LSE's forecasted annual load share, and LSE's will pay the applicable year's market price benchmark (MPB) for RPS attributes received.
- Long-term allocations are fixed over the delivery period of the Voluntary Allocation Contract and once accepted may not be declined in future years.
- A long-term allocation election is set as a fixed percentage of the LSE's forecasted annual load share, and both the forecasted annual load share and the RPS energy delivery amounts will change from year-to-year based on updated forecasts of annual loads.
- LSEs are able to resell their Voluntary Allocation shares of RPS energy, subject to the same RPS compliance requirements as IOU sales, and LSE reporting requirements will be established in the RPS proceeding.

No protests were filed, and PG&E's requested effective date was March 30, 2022.

AL 6551-E Market Offer Contract proposal

PG&E submitted the Tier 2 Advice Letter 6551-E requesting approval of a pro forma Market Offer Contract for Power Charge Indifference Adjustment (PCIA)-eligible Renewables Portfolio Standard (RPS) resources, on April 4, 2022, as required by D.22-01-004. PG&E requests this Tier 2 AL submittal become effective on **May 4, 2022**. Protests/responses are due **April 25, 2022**.

This proposed Market Offer Contract is specific to the requirement of D.21-05-030 that all PCIA-eligible RPS energy remaining after a Voluntary Allocation be offered for sale in the Market Offer. The other two requirements of D.21-05-030 – that the Market Offer process 1) be based upon existing processes, rules, oversight requirements, and reporting requirements for REC solicitations previously approved in the Commission's RPS proceeding; and 2) include rules for utility participation in utility-administered solicitations – were addressed in the IOU's Joint Motion in R.18-07-003 (filed March 10, 2022).

Since PG&E's Market Offer Contract is a confirmation to PG&E's Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement (Master Agreement), similar to the existing confirmation used in PG&E's bundled RPS energy sales, Market Offer process participants will need a Master Agreement in place with PG&E prior to execution of the Market Offer Contract.

Details of the proposed pro forma Market Offer Contract include:

- A Market Offer participant may bid for all the PCIA-eligible RPS portfolio that remains following Voluntary Allocation.
- PG&E proposes to deliver the PCIA-eligible RPS energy remaining after Voluntary Allocation over the final two years of the current RPS compliance period (i.e., 2023 & 2024) for reasons that include reducing administrative risk, providing flexibility for all LSEs, and enabling reevaluation for future Market Offers.

The proposed contract differs from PG&E's CPUC-approved bundled RPS energy sale contract in the products offered and their delivery periods. The RPS energy sale contract only includes fixed volumes of bundled RECs available for purchase in calendar year 2022, while the proposed contract includes portions of PG&E's PCIA-eligible RPS portfolio that remain unallocated following Voluntary Allocation that will be delivered over 2023 and 2024, like PG&E's existing carbon-free allocation contract.

Analysis: The two proposed contracts for procurement of PCIA-eligible RPS resources provide details of the terms for procurement of PCIA-eligible RPS resources under the Voluntary Allocation and Market Offer processes. Specifically, they address product quantities, delivery periods, and pricing in the case of Voluntary Allocation.

Next Steps: PG&E posted a [webpage](#) with updated timelines for 2022 Voluntary Allocations:

- **April 2022:** PG&E completes initial 2023 load forecasting in line with Meet-and-Confer process within ERRA and/or RA proceedings.
- **May 16, 2022:** PG&E files ERRA Forecast Application and informs LSEs of initial forecast allocation shares for 2023 Voluntary Allocation.
- **May 16 – June 10, 2022:** Voluntary Allocation contracting with LSEs
- **June 10, 2022:** Final day for LSEs to submit Voluntary Allocation elections to PG&E.
- **June 2022:** PG&E completes Voluntary Allocation contracting.
- **Summer 2022:** LSEs file Draft 2022 RPS Plans informed by Voluntary Allocation elections.
- **October 2022:** Each IOU informs LSEs of updated allocation shares for 2023 Voluntary Allocations.

Additional Information: [Market Offer Contract](#) (AL 6551-E) for PCIA-eligible RPS Resources remaining after VA (April 4, 2022); [Voluntary Allocation Contract](#) (Advice 6517-E) for PCIA-eligible RPS Resources (February 28, 2022); [D.22-01-023](#) on Phase 2 (approved January 27, 2021); [Ruling](#) requesting comments on PCIA forecasting data access (November 5, 2021); [Voluntary Allocation Methodology Advice Letter 6305-E](#) (October 25, 2021); [Ruling](#) requesting comments (September 17, 2021); CalCCA [Application for Rehearing](#) of D.21-05-030 (June 23, 2021); [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); [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); [D.20-01-030](#) denying rehearing of D.18-10-019 as modified (January 21, 2020); [D.19-10-001](#) (October 17, 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](#).

NEW PG&E 2021 ERRA Compliance

PG&E filed its 2021 ERRA Compliance application on February 28, 2022, in which it requests the CPUC find that the company complied with its CPUC-approved Bundled Procurement Plan, reasonably managed utility-owned generation facilities, and made other reasonable expenditures and accounting entries consistent with CPUC directives.

Background: N/A

Details: PG&E requests that the CPUC find that during 2021:

- It complied with its CPUC-approved 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.
- It managed its utility-owned generation (UOG) facilities reasonably.

- Its expenditures in the Green Tariff Shared Renewables Memorandum Account (GTSRMA) were reasonable.
- Its entries in the Portfolio Allocation Balancing Account (PABA), Energy Resource Recovery Account (ERRA), Green Tariff Shared Renewables Balancing Account (GTSRBA), Disadvantaged Community – Single-Family Affordable Solar Homes (DAC SASH) balancing account (DACSASHBA), Disadvantaged Community - Green Tariff Balancing Account (DACGTBA), and Community Solar Green Tariff Balancing Account (CSGTBA) were consistent with applicable tariffs and CPUC directives.

PG&E also presents its Central Procurement Entity's administrative costs recorded to the Centralized Local Procurement Sub-Account (CLPSA) in the New System Generation Balancing Account (NSGBA).

PSPS Impacts

PG&E states that since the CPUC is currently considering the utilities' proposed common methodology for calculating unrealized volumetric sales and unrealized revenues resulting from PSPS events in the consolidated Phase II 2019 ERRA Compliance proceeding, it has not included with this 2021 ERRA Compliance application any testimony addressing the calculation of unrealized volumetric sales or unrealized revenues. PG&E plans to send an email to the assigned ALJ requesting direction regarding whether and in what format PSPS information should be presented as part of this Application once the Commission has resolved the issue in the Phase II 2019 ERRA Compliance proceeding.

Testimony

Regulatory case documents are available [here](#) by selecting "ERRA 2021 PGE - Compliance..." from the "Case" drop down. PG&E's testimony is [here](#) (423 pages). It covers:

- Chapter 1 Least-Cost Dispatch and Economically Triggered Demand Response
- Chapter 2 Utility-Owned Generation: Hydroelectric
- Chapter 3 Utility-Owned Generation: Fossil and Other Generation
- Chapter 4 Utility-Owned Generation: Nuclear
- Chapter 5 Review Entries Recorded in the Disadvantaged Community – Green Tariff Balancing Account and the Community Solar Green Tariff Balancing Account
- Chapter 6 Generation Fuel Costs and Electric Portfolio Hedging
- Chapter 7 Greenhouse Gas Compliance Instrument Procurement
- Chapter 8 Resource Adequacy
- Chapter 9 Contract Administration
- Chapter 10 CAISO Settlements and Monitoring
- Chapter 11 Review Recorded in the Green Tariff Shared Renewables Memorandum Account and the Green Tariff Shared Renewables Balancing Account
- Chapter 12 Summary of PABA Entries for the Record Period
- Chapter 13 Summary of ERRA Entries for the Record Period
- Chapter 14 Maximum Potential Disallowance

- Chapter 15 Review Entries Recorded in the Disadvantaged Community – Single-family Affordable Solar Homes Balancing Account and the Disadvantaged Community - Single-family Affordable Solar Homes Memorandum Account
- Chapter 16 Central Procurement Entity – Entries Recorded in the Centralized Local Procurement Sub-Account

Issues

PG&E proposes the following issues be considered in this proceeding:

- Whether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4):
 - Utility-Owned Generation Facilities
 - Qualifying Facilities (QF) Contracts and Non-QF Contracts. If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?
- Whether PG&E achieved least-cost dispatch of its energy resources and economically triggered demand response programs pursuant to SOC 4;
- Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions;
- Whether PG&E's greenhouse gas instrument procurement complied with its Bundled Procurement Plan;
- Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan;
- Whether the costs incurred and recorded in the following accounts are reasonable and in compliance with the applicable tariffs and Commission directives:
 - Green Tariff Shared Renewables Memorandum Account;
 - Green Tariff Shared Renewables Balancing Account;
 - Disadvantaged Community - Single Family Solar Affordable Homes Balancing Account;
 - Disadvantaged Community - Green Tariff Balancing Account;
 - Community Solar Green Tariff Balancing Account;
 - Centralized Local Procurement Sub-Account.
- Whether there are any safety considerations raised by this Application

Analysis: The proceeding has just begun, and its full scope is yet to be determined. A CPUC determination in the Phase II 2019 ERRR Compliance proceeding on the utilities' proposed common methodology for calculating unrealized volumetric sales and unrealized revenues resulting from PSPS events could expand the scope of this proceeding.

Next Steps: Deadline for filing protest/response ended April 8, 2022.

PG&E has proposed the following timeline:

- **May 11, 2022:** Prehearing Conference
- **July 22, 2022:** Cal Advocates and Intervenor Testimony

- **August 26, 2022:** PG&E Rebuttal Testimony
- **September 2022:** Settlement Discussions
- **September 13-16, 2022:** Evidentiary Hearings
- **October 17, 2022:** Opening Briefs
- **November 4, 2022:** Reply Briefs

Additional Information: PG&E 2021 ERRR Compliance [Application](#) (February 28, 2022); Docket No. [A.22-02-015](#).

PG&E Phase 2 GRC

The single carryover issue of material fact about the MGCC Property Tax Adder was resolved with issuance of a Final Decision adopting the Joint Stipulation on March 18, 2022. PG&E's MGCC Report was filed March 17, 2022, and PG&E filed its non-NEM export compensation proposal for BEV on March 24, 2022.

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. D.21-11-016 largely adopted PG&E's proposed marginal costs and methodologies for deriving them but adopted 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 adopted, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; Economic Development Rate (EDR) settlement; agricultural rate design; C&I rate design) and revenue allocation.

With respect to CCA issues, the adopted EDR settlement noted 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." D.21-11-016 also approved 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 will use the most recent vintage of the PCIA rate. Finally, D.21-11-016 approved 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.

On January 18, 2022, parties filed a Settlement Agreement includes the following terms of the Stage 1 RTP Pilot:

Eligibility: PG&E's bundled customers who are eligible for the B-20, B-6 and E-ELEC rates may participate on an opt-in basis. CCAs will need to affirmatively decide to participate in the Stage 1 Pilots for their customers to be eligible. PG&E agrees to work with its twelve CCAs to seek agreement from one or two of them to participate in the Stage 1 Pilots, if possible.

Duration: Stage 1 Pilots shall have a duration of 24 months, subject to potential extension.

Enrollment: PG&E will make its best efforts to program and make available for enrollment the three Stage 1 RTP rates by October 1, 2023.

Pricing: The RTP element of the Stage 1 Pilot RTP rates will replace the generation component of the customer's otherwise applicable rate schedule. The remaining transmission, distribution, Public

Purpose Program and other charges and taxes remain the same as the otherwise applicable underlying rate. The generation component to be used in the Stage 1 Pilots' RTP rates will include: (1) a Marginal Energy Charge, (2) a Marginal Generation Capacity Cost, and (3) a Revenue Neutral Adder (designed to make the forecasted annual generation revenue collected under the three Stage 1 Pilot RTP rates revenue neutral to the base schedule). Residential customers would have 1 year bill protection. There would be a limited amount of participation incentives as well.

All development, implementation, and operating costs for the Stage 1 Pilots, as well as for the separate Customer Research Study for residential, agricultural, and small commercial customers, will be recovered in distribution rates from all customers.

Details: The Final Decision, D.22-03-012, adopting the Joint Stipulation, or otherwise resolving the single carryover issue of material fact about the MGCC Property Tax Adder, was issued March 18, 2022. This Decision, in accordance with the PG&E/CLECA Joint Stipulation, adopts a property tax factor of 1.25% for the 2021-2026 marginal generation capacity cost (MGCC) for new customer rates effective June 1, 2022. A corrected version of PG&E's MGCC Report was filed on March 17, 2022.

PG&E proposed an export compensation mechanism for non-NEM customers enrolled in the Day-Ahead Hourly Real Time Pricing (DAHRTP) rate. The proposed Business Electric Vehicle (BEV) Pilot will include customers on any BEV rate and not only customers on the DAHRTP Commercial Electric Vehicle (CEV) rate. Compensation for energy will come from the CAISO market participation entity, and to the extent available will include compensation for Resource Adequacy. PG&E has not yet proposed a budget for the Pilot but has proposed a cost-effectiveness evaluation and a report on lessons learned to be issued two years after implementation. The proposal includes a market participation option instead of a tariff rate to allow all BEV customers in the PG&E service territory (including customers of CCAs or direct access providers) to participate without requiring each retail LSE to offer its own tariff rate. Some key considerations that PG&E has requested be addressed through a stakeholder process include interconnection jurisdiction, resource adequacy compensation methodology, and managing and monitoring customer revenue generation.

Analysis: This phase of the proceeding could impact real-time pricing rate design issues for PG&E customers. If the settlement agreement is adopted, VCE could elect to allow its customers to participate in the Stage 1 RTP Pilot. The Settlement Agreement provides that cost recovery of development, implementation, and operating costs for the Stage 1 Pilots, as well as for the separate Customer Research Study, would be recovered in distribution rates that both bundled PG&E and VCE customers pay.

Next Steps: The proceeding remains open to address RTP issues, and PG&E testimony on its RTP Proposal is due April 13, 2022. An Advice Letter outlining pilot details is expected from PG&E, the timing of which will be addressed in the April 13 testimony.

Additional Information: PG&E [Proposal](#) for non-NEM export compensation (March 24, 2022); PG&E [MGCC Report](#) (corrected) (March 17, 2022); [Decision](#) on property tax adder (March 18, 2022); [Ruling](#) on timing to respond to PG&E/CLECA Motion (January 25, 2022); [Motion](#) by PG&E/CLECA to establish a separate expedited schedule (January 21, 2022); PG&E [Motion](#) on MGCC Study (January 18, 2022); PG&E [Motion](#) (January 18, 2022); [Motion](#) to Adopt Settlement Agreement (January 18, 2022); [D.21-11-016](#) on revenue allocation and rate design (November 19, 2021); [Amended Scoping Memo and Ruling](#) (August 25, 2021); [Ruling](#) bifurcating RTP issues into separate track (February 2, 2021); [D.20-09-021](#) on EUS budget (September 28, 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); RTP Pilot Docket No. [A.20-10-011](#); Phase 2 GRC Docket No. [A.19-11-019](#).

PG&E Phase 1 GRC

PG&E filed an Amended Application and submitted supplemental testimony on wildfire mitigation programs in March 2022. A March 10 ALJ Ruling denied the Motion to Shorten Time filed by TURN, PG&E, and PAO, and suspended the March 30, 2022, deadline for intervenor testimony pending a ruling on their February 16, 2022, Motion to Modify the Schedule. PG&E filed its recorded expense and capital cost data for 2021 on March 9, 2022. Public Participation Hearings were held on three days during March 2022 regarding the February 2022 joint report, submitted by PG&E and Caltrain, on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco.

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.

The October 1, 2021, Scoping Memo and Ruling divided 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.

PG&E's pending November 5, 2021, Motion requests extending the turn-around time for filing rebuttal testimony from 30 days to 45 days; delaying the start of evidentiary hearings by three weeks to accommodate the proposed rebuttal testimony timeline; and requested an earlier resolution that Q4 2022 as indicated in the Scoping Memo and Ruling of PG&E's July 16, 2021, Motion for a January 1, 2023 effective date for its 2023 revenue requirement.

Details: On March 10, 2022, PG&E filed an Amended Application and submitted supplemental testimony on wildfire mitigation programs. Also on March 10, 2022, the ALJ issued a Ruling on the February 25 Motion filed by TURN, PG&E, and PAO denying their request to shorten time for responses to PG&E's amended application and supplementary testimony on wildfire mitigation

programs, and suspending the March 30, 2022, submission date for intervenor testimony pending a ruling on the February 16, 2022, Motion to Modify the Schedule filed by TURN, PG&E, and the PAO.

On March 9, 2022, PG&E submitted its recorded expense and capital data testimony for 2021.

PG&E and Caltrain submitted a joint report on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco. PG&E and Caltrain also requested to move consideration of PG&E's proposal for cost recovery of Caltrain Project costs from Track 1 to Track 2 of PG&E's 2023 GRC and proposed a schedule for the submission of testimony reporting on the Audit.

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 March 30, 2022, deadline for intervenor testimony was suspended pending a ruling on the February 16, 2022, Motion to Modify the Schedule. The next steps in Track 1 are a ruling on the procedural schedule modifications and a PG&E affordability metrics report at least one month before intervenor testimony. 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: ALJ [Ruling](#) denying Motion to Shorten Time, accepting PG&E's Amended Application, and suspending intervenor testimony deadline (March 10, 2022); PG&E's [Amended Application](#) (March 10, 2022); PG&E [Affordability Metrics Report](#) (February 23, 2022); ALJ [Ruling](#) on Public Participation Hearings (February 2, 2022); PG&E/Caltrain Report (February 1, 2022); [Ruling](#) denying PG&E Motion to submit supplemental testimony (November 12, 2021); [Motion](#) of PG&E to modify procedural schedule (November 5, 2021); [Scoping Memo and Ruling](#) (October 1, 2021); [PG&E Application](#) (June 30, 2021); Docket No. [A.21-06-021](#).

RA Rulemaking (2023-2024)

On March 18, 2022, the CPUC issued a Decision on Phase 1 of Implementation Track Modifications that made several changes to the CPE, including changes encouraging LSEs to self-show resources and modifying the timeline of CPE activities. This Decision concludes Phase 1 of the Implementation Track Modifications.

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 December 2, 2021, Scoping Memo and Ruling divided the proceeding into an Implementation Track and Reform Track. The Reform Track encompasses consideration of a final proposed framework and the slice-of-day workshop report.

The Implementation Track is sub-divided into Phases 1, 2, and 3:

- Phase 1 of the Implementation Track considered critical modifications to the CPE structure and concluded in March 2022 with issuance of D.22-03-034.
- Phase 2 consists of the Commission’s consideration of flexible capacity requirements for the following year, local capacity requirements for the next three years, and the highest priority refinements to the RA program, which include: modifications to the Planning Reserve Margin Qualifying Capacity Counting Conventions, which among other proposals will consider the Energy Division’s biennial update to the Effective Load Carrying Capability values for wind and solar resources, including the development of regional values for wind resources. Phase 2 proposals were submitted in January 2022 and this phase is expected to conclude in June 2022. Neither CalCCA nor any CCAs individually filed a Phase 2 proposal.
- Phase 3 will consider the 2024 program year requirements for flexible RA, and the 2024-2026 local RA requirements. Other modifications and refinements to the RA program, as identified in proposals by parties or by Energy Division may also be considered. Phase 3 is expected to conclude by June 2023

Details: The CPUC adopted SCE’s proposal with CalCCA’s modifications to the PD of requirements for non-performance of self-shown local resources such that 1) self-showing LSEs are allowed to provide a substitute resource to replace non-performing self-shown local resources, and 2) LSEs will be allocated, on a load ratio share basis, any backstop procurement costs charged to the CPE in the event the CAISO makes a local CPM designation for an individual deficiency. The CPUC also replaced the previous requirement (Ordering Paragraph 3 in D.20-12-006) that a shown resource must be documented on an agreement as determined by the CPE with new attestation requirements for an LSE electing to self-show a local resource to the CPE, as follows:

- The LSE has the capacity rights to the RA resource for the self-shown period;
- The LSE intends to self-show the RA resource on monthly and annual RA plans to satisfy its system or flexible RA needs; and,
- That compensated self-shown resources under the LCR RCM meet the eligibility requirements under D.20-12-006, if applicable.

Given the shortfalls in the PG&E CPE’s procurement process and the low participation rates in the CPE solicitation process, the CPUC is requiring LSEs that decline to self-show or bid to submit a justification with their year-ahead RA filing explaining their rationale for informational purposes for the Commission. Also, an LSE’s self-shown commitment for years 1 and 2 must be firm, but self-shown local resources for year 3 may be replaced like-for-like with other local resources.

The Decision modified the RA central procurement entity (CPE) selection process by removing the local effectiveness factors as a criterion and clarifying that length of contract term requirements are not authorized by the Commission and that the CPE must consider bids of any contract term length greater than or equal to one month. Additionally, the Decision allows CPEs to procure outside of the annual solicitation process if there are deficiencies following the CPEs’ annual solicitation and only to cover those deficiencies, and CPEs are encouraged to fill those positions to the extent possible before initial RA allocations in July.

The CPUC adopted a modified CPE procurement timeline under which LSEs in the PG&E TAC make self-shown commitment to the CPE for applicable RA years no later than mid-May, LSEs receive initial RA allocations in July and updated CAM credits procured by the CPE in August, LSEs receive final year-ahead system and flexible RA allocations in September, and final LSE showings are made by the end of October.

Analysis: The Decision made several changes to the CPE, including changes encouraging LSEs to self-show resources and modifying the timeline of CPE activities. The results of the LOLE study

could impact the thinking and formation of the slice-of-day reliability framework being developed in the RA Reform Track of this proceeding that seeks to ensure load 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.

Next Steps: The procedural schedule for the ongoing tracks and working groups are as follows:

Phase 1

- Concluded in March 2022 with issuance of D.22-03-034

Phase 2

- CAISO draft 2023 LCR Report: April 15, 2022
- Comments on draft 2023 LCR Report: April 22, 2022
- CAISO final 2023 LCR and FCR Report: April 29, 2022
- Comments on final 2023 LCR and FCR Report: May 6, 2022
- Reply comments on final 2023 LCR and FCR Report: May 13, 2022
- Proposed Decision: May 2022
- Final Decision: June 2022

Reform Track

- BTM Counting Convention Working Group meeting dates (9am-1pm): February 22, 2022 meeting was postponed (new date TBD).

Additional Information: [D.22-03-034](#) on Phase 1 of Implementation Track Modifications (March 18, 2022); [Workshop Report](#) (February 28, 2022); [Ruling](#) modifying Phase 2 schedule and providing LOLE study and CEC Working Group Report (February 18, 2022); [Proposed Decision](#) on CPE revisions (February 10, 2022); [Ruling](#) modifying procedural schedule (December 10, 2022); [Scoping Memo and Ruling](#) (December 2, 2021); [Order Instituting Rulemaking](#) (October 11, 2021); Docket No. [R.21-10-002](#).

RA Rulemaking (2021-2022)

On March 18, 2022, the CPUC issued a Proposed Decision that would deny OhmConnect's September 2021 Petition for Modification of D.20-06-031 to increase the demand response Maximum Cumulative Capacity limit of 8.3% to 11.3%.

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, now in R.21-10-002): 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 argued that the change is needed to 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, but the Proposed Decision would find that such portion of the Governor's proclamation expired. The Proposed Decision would also find that the PFM was not timely because it was filed in September 2021 (more than 1 year after D.20-06-031).

Analysis: Increasing the demand response cap, as OhmConnect requested and CCAs and others supported, would allow LSEs like VCE to procure a higher percentage of demand response resources to meet RA obligations than is currently allowed under the RA compliance rules. Any future proposals to broadly increase the demand response cap will require consideration of how doing so will affect grid reliability.

Next Steps: Comments on the PD are due April 7, replies are due April 12, and the PD may be adopted, at earliest, at the April 21 CPUC meeting.

Additional Information: [Proposed Decision](#) denying OhmConnect's September 2021 petition; 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](#).

PG&E 2020 ERRR Compliance

On March 16, 2022, the CPUC issued a Proposed Decision for Phase 1 in which the Settlement Agreement filed by the parties on October 15, 2021, was found to be reasonable and therefore resolves all the disputed issues in this proceeding. Phase 2 of the proceeding, which remains open, will address issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

Background: The annual ERRR 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 ERRR 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 ERRR 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 ERRR 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.

The Proposed Decision requires that PG&E include further testimony in their 2021 Compliance case describing the actions that PG&E has taken to address the deficiencies reported in its Internal Audit Report on the PABA; an internal audit closure document with details of PG&E’s implementation of any action plans to address the deficiencies reported in the Internal Audit Report; testimony from its Chief Regulatory Officer on the actions that PG&E will take or has taken to ensure that there is proper accounting and recording of entries in the various balancing and memorandum accounts review in the ERRA compliance proceedings, including, but not limited to, the PABA.

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 Final Decision to formally conclude Phase 1, followed by consideration of issues in Phase 2 of the proceeding.

Additional Information: [Proposed Decision](#) (March 16, 2022); [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

Comments on the March 7, 2022, workshop to discuss the proposed framework for considering the issues and recommendations resulting from the previous Phase 1 workshop were filed March 28, 2022.

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 issued September 16, 2021, provides that 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.

On December 17, 2021, parties filed comments in response to the November 23, 2021, ALJ Ruling posing questions addressing: (1) clarity and content of the Workshop 1 notes filed by CalCCA on November 5, 2021, and (2) questions on Workshop 1 and what changes if any are recommended to adequately meet POLR requirements. CalCCA comments included the following recommendations:

- POLR service should be limited to 60 days to allow returned customers to transition from the returning LSE to the customer's chosen LSE, consistent with the existing "safe harbor" provision for DA switching.
- Given the limited term and scope of service and the need to avoid unnecessary costs, the POLR should not engage in advance procurement or hedging.
- RPS and IRP responsibility for returned customers should shift directly from the returning LSE to the customer's new LSE, with a waiver of these obligations for the POLR consistent with the existing waiver for RA obligations adopted in D.20-06-031.
- The CPUC should compare Reentry Fees and actual costs for Western Community Energy's customer return to determine whether the current formulation provides sufficient precision to ensure a reasonable outcome.
- A POLR right of first refusal of procurement contracts held by the returning LSE raises legal and commercial issues and should not be considered.
- To minimize the risk of LSE default by newly launched CCA, Implementation Plan requirements should be modified to incorporate a milestone procedure to be administered by the CCA's governing board, quarterly updates to Energy Division on the status of milestone achievement, transparency through the use of a publicly available information portal available, and feasibility studies provided to the local governing board built on transparent and standardized referents.
- Financial service requirements (FSR) should vary with the financial health of an LSE, limiting FSRs for LSEs maintaining investment-grade credit ratings and LSEs voluntarily providing limited metrics to the CPUC for review; all other LSEs should bear responsibility for the currently formulated FSR.

Details: The recorded proceedings and presentation slides of the March 7, 2022 workshop are available on the CPUC's [Provider of Last Resort webpage](#). Party comments on the workshop were filed on March 28, 2022 (with the exception that PG&E mistakenly filed [comments](#) in the wrong

docket and filed a motion requesting approval to late-file comments). CalCCA's comments on the workshop urged a more pragmatic approach based on recent actual experience of customer returns and an evidence-based examination of the actual risks of customer returns to addressing POLR issues rather than the seeming focus on "Black Swan"-type events. Some of CalCCA's proposals include maintaining the six-month runway to prepare for the return of customers, refining the FSRs to reflect the current MPBs for RA and RPS products, maintaining the existing right to an RA waiver, not requiring resource procurement in advance of customer returns, provide for recovery of financing costs if the POLR must pay for costs prior to receipt of revenues from customer returns, refining the implementation planning process for new CCAs, and implementing a three-tiered reporting rubric calibrated to the operating CCA's circumstances.

PG&E's comments included a proposal for an insurance pool to ensure liquidity equal to about two months incremental energy procurement costs for the POLR with each CCS posting its annual contribution to the insurance pool in the form of either cash or a letter of credit, and a proposed initial set of metrics for monitoring the financial health of CCAs that the company recommended be further developed and refined through a workshop process or with other stakeholder feedback.

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 Joint Case Management Statement with request for evidentiary hearings and/or briefs was expected in Q1 2022 according to the September 2021 Scoping Memo, but no additional information regarding scheduling is currently available. Then, if needed, evidentiary hearings in Q2 2022, and opening and closing briefs in Q3 2022.

Additional Information: [Ruling](#) rescheduling second workshop date (February 24, 2022); [Ruling](#) setting second workshop and comment period (December 31, 2021); [Ruling](#) requesting comments (November 23, 2021); 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](#).

RA Rulemaking (2019-2020)

No updates this month. Rulemaking is effectively closed, except for one outstanding application for rehearing that was filed in August 2020.

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. D.20-06-028 adopted revisions to the Resource Adequacy import rules based on Energy Division's proposal, with modifications.

In [Track 2](#), the CPUC 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 a multi-year requirement 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 a 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.

Details: D.22-02-008 denied WPTF's July 17, 2020, Application for Rehearing of D.20-06-002, the Track 2 Decision creating a multi-year central procurement regime for local RA capacity. WPTF had 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. D.22-02-008 found that good cause for rehearing had not been demonstrated.

The only remaining item to be addressed in this proceeding is one outstanding application for rehearing of D.20-06-028 filed by WPTF on August 5, 2020. D.20-06-028 relates to the self-scheduling requirements for non-resource specific RA imports.

Analysis: D.22-02-008 upheld the CPUC's decision, D.20-06-002, which established a CPE. Moving to a CPE beginning for the 2023 RA compliance year impacted 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.

Next Steps: The only item remaining to be addressed in this proceeding is WPTF's remaining outstanding Application for Rehearing. Remaining RA issues will be addressed in the successor RA rulemakings.

Additional Information: [D.22-02-008](#) denying WPTF's Application for Rehearing (February 11, 2022); [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](#).

Utility Safety Culture Assessments

A telephonic Prehearing Conference was held on March 30, 2022, to determine the parties, scope, schedule of the proceeding, and other procedural matters.

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 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.

A [webinar recording](#) of the March 11, 2022, workshop is available, and additional information on the proceeding is posted on the CPUC's [Safety Culture and Governance webpage](#).

Details: The Prehearing Conference discussed the adoption of a definition of "safety culture" by the Commission, the scope and mechanisms that should be adopted in a safety culture assessment framework, the schedule and process to be applied to safety culture assessments, and metrics and methodologies for measuring safety culture change. A [transcript](#) of the March 30 teleconference was filed on April 4, 2022.

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: A Procedural Order determining issues addressed in the Prehearing Conference is expected; timing TBD.

Additional Information: [Order Instituting Rulemaking](#) (October 7, 2021); Docket No. [R.21-10-001](#).

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

No updates this month. On December 6, 2021, the CPUC issued D.21-12-006 adopting 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 2022 Wildfire Fund Non-Bypassable Charge is \$0.00652/kWh, up from \$0.0058/kWh in 2021. The reason for this 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 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: The Department of Water Resources will issue a notice in September 2022 identifying the amount they calculate will need to be the 2023 Wildfire Fund Non-Bypassable Charge.

Additional Information: [D.21-12-006](#) on Wildfire NBC for 2022 (December 6, 2021); [Ruling](#) requesting comments on 2022 Wildfire Fund NBC (September 8, 2021); [Scoping Memo and Ruling](#) (June 8, 2021); [Order Instituting Rulemaking](#) (March 10, 2021); Docket No. [R.21-03-001](#).

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

No updates this month except to note that on March 7, 2022, Investigation 15-08-019 was reassigned from President Marybel Batjer to Commissioner John R.D. Reynolds.

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.

On October 25, 2021, President Batjer sent a letter to PG&E asserting 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

Details: No updates.

Analysis: The August 18, 2021, and October 25, 2021, CPUC letters to PG&E indicate the CPUC has significant concerns with PG&E's outages related to both PSPS events and 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.

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. The statutory deadline for a final decision was extended to June 30, 2022 in an order issued December 16, 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. The current statutory deadline extension expires on June 30, 2022.

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](#).

PG&E 2022 ERRA Forecast

No updates this month. On February 11, 2022, the CPUC issued D.22-02-002, resolving all issues and closing the proceeding.

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's Fourth Supplemental Testimony included both an "October Update" and a "December Update." A group of CCA parties recommended in comments that the CPUC adopt the proposed forecasted revenue requirements and associated rates from the December Update and requested the rates be implemented by February 1, 2022. The CCA parties said that adopting the December update would reduce likely volatility between 2022 and 2023 rates and that adoption of an October Update would clearly violate State law and Commission precedent. The CCAs noted that PG&E's forecasted costs to serve load in 2022 are 66.5% higher than in 2021.

CalCCA and the Joint CCAs support a 12-month amortization of the revenue requirements presented in the December Update, rather than the 18-month or 24-month scenarios presented by PG&E in its Fifth Supplemental Testimony in late December. PG&E and DACC also support the 12-month amortization, and Public Advocates Office does not oppose it. In contrast, the California Large Energy Consumers Association, Agricultural Energy Consumers Association, and California Farm Bureau Federation advocate for a 24-month amortization period.

Details: D.22-02-002 approves a 2022 forecast of electric sales and energy procurement revenue requirements of \$2.4 billion, effective in rates on March 1, 2022. It finds the December Update, updated again with the actual year end ERRA-main account balance provides the most accurate forecast for 2022 revenue requirements, and approves the 12-month amortization that was supported by CCAs. Under the December Update adopted in D.22-02-002, **the 2022 total PCIA rate for 2017-vintaged customers (i.e., most VCE customers) will fall 59% relative to 2021 to**

\$0.01969/kWh for residential customers and to \$0.01897/kWh on a system-average basis. It also agrees with the Joint CCAs and DACC that all customers who were financially responsible for the ERRA-PCIA Financing Subaccount (ERRA-PFS) balance should be entitled to the appropriate credit and direct PG&E to transfer the \$95 million ERRA-PFS credit for 2022 to the 2020 vintage subaccount. It approves a request by CCAs and directs PG&E to include the confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding. D.22-02-002 denies without prejudice the CCA's request to direct PG&E to provide data demonstrating its future role as a CPE in future ERRA forecast proceedings.

On March 14, 2022, the California Large Energy Consumers Association and Agricultural Energy Consumers Association filed an Application for Rehearing (AFR) of D.22-02-002. The AFR argues that the Commission should have adopted a 24-month amortization period for the undercollected ERRA balance. PG&E filed its response to the AFR on March 29, 2022, defending the use of a 12-month amortization period. The Commission has not yet acted on the AFR.

Analysis: D.22-02-002 results in a 59% reduction to VCE's PCIA rates in 2022 compared to 2021. While the PCIA rate will fall substantially in 2022 for VCE customers, the non-RPS benchmarks that contributed to the reduction in the PCIA in 2022 could result in the opposite effect in 2023. That is, the same high benchmarks that helped reduce the 2022 year's forecast case may be too high compared to next year's actuals, which would create large PABA undercollection balances for 2023 rates. The change in the PCIA rate from the December Update will help mitigate such a swing in rates in 2023. D.22-02-002 also improves transparency by approving the CCAs' request for PG&E to provide confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding.

Next Steps: The proceeding is now closed. However, as described above, an application for rehearing is pending.

Additional Information: [D.22-02-002](#) (January 24, 2022); [Ruling](#) modifying procedural schedule (January 14, 2022); [Ruling](#) directing PG&E to provide amortization scenarios (December 17, 2021); [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

No update this month except to note that Opening Briefs are due May 6, 2022. On March 23, 2022, consolidated Application (A.) 20-02-009, A.20-04-002 and A.20-06-001 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds.

Background: Joint IOU rebuttal testimony was filed February 15, 2022, and a Joint Case Management Statement was submitted February 25, 2022.

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.

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. The Joint IOUs' testimony provided additional information on the common methodology for calculating the potential unrealized sales that may result from a PSPS event to be used in a potential rate disallowance, which relies on the energy-related portion of the CPUC-jurisdictional distribution charge for this purpose. CCA representatives pushed back at the October 26, 2021, workshop 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.

Accordingly, the Joint CCAs filed a motion on November 4, 2021, requesting the CPUC clarify the scope of issues in this proceeding. The November 12, 2021, Ruling clarified the CPUC's intent to consider a range of PSPS methodologies, which may be proposed by both the IOUs and other parties. It provided that parties may conduct additional discovery to support their proposal of a reasonable alternative PSPS methodology. The CPUC will consider a PSPS methodology that includes unrealized generation-related volumetric sales and revenues, along with the joint IOU proposal and potentially other PSPS methodologies

Details: The Joint IOUs' recommendations to adopt their common methodology for calculating unrealized revenue from end-use customers de-energized during PSPS events were determined to be reasonable and approval was recommended in the Joint Case Management Statement.

Previously, the CCA Parties' testimony identified all retail rate components that should be considered to provide a full accounting of the unrealized retail revenue during PSPS events. The testimony also described how, absent a ratemaking remedy, the IOUs will fully recover their authorized revenue requirement from all customers, including those receiving no electricity service during PSPS events, through pre-established balancing account mechanisms. The CCA Parties also explained the potential impact of PSPS events on wholesale generation revenue and the need to account any such reductions if generation resources are forced offline due to PSPS events.

The CCA Parties recommended the following issues which remain in dispute per the Joint Case Management Statement:

- The calculation of unrealized retail revenue during PSPS events should include additional CPUC-jurisdictional rate components tied to balancing accounts that record IOU costs incurred despite lost sales to end use customers.
- Each IOU should make a full accounting of the balancing accounts implicated by the total unrealized retail revenue.
- Unrealized wholesale generation revenue should be quantified if utility-owned generation resources, or contracts with take-or-pay provisions, are forced out of service due to a PSPS event.
- Each IOU should record adjusting entries to affected balancing accounts, equal to the unrealized retail and wholesale generation revenue as applicable, to comply with the Commission's directive to "forgo collection in rates from customers of all authorized revenue requirement equal to estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events."

TURN also filed testimony recommending that all revenue requirements from retail sales be disallowed.

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: Opening Briefs are due May 6, 2022, and Reply Briefs are due June 3, 2022.

Additional Information: [Joint Case Management Statement](#) (February 25, 2022); [Order](#) Denying Rehearing of D.21-07-018 and PG&E's application for rehearing of D.21-07-013 (December 3, 2021); [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](#).

Direct Access Rulemaking

On March 1, 2022, Rulemaking 19-03-009 was reassigned from Commissioner Martha Guzman Aceves to Commissioner John R.D. Reynolds. 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 filed by direct access advocates.

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](#).

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BEV	Business Electric Vehicle
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)