VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 7

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: February 10, 2022

Please find attached Keyes & Fox's January 2022 Regulatory Memorandum dated February 4, 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 February 4, 2022.

KEYES&FOX LLP

Valley Clean Energy Alliance

Regulatory Monitoring Report

To:	Valley Clean Energy Alliance ("VCE") Board of Directors
From:	Sheridan Pauker, Partner, Keyes & Fox LLP Tim Lindl, Partner, Keyes & Fox LLP Ben Inskeep, Principal Analyst, EQ Research, LLC
Subject:	Regulatory Update
Date:	February 4, 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:** VCE submitted Advice Letter 11-E on January 5, 2022, detailing information on its implementation of its agricultural irrigation pumping dynamic rates pilot. On January 25, 2022, PG&E filed a protest of VCE's AL 11-E, to which VCE replied on January 31, 2022. On January 31, 2022, VCE, Polaris and TeMix filed a Petition for Modification of D.21-12-015 to authorize a VCE administrative budget for the pilot.
- **IRP Rulemaking:** On January 27, 2022, the CPUC decided to hold until its February 10, 2022, meeting a vote on the Proposed Decision adopting a 2021 Preferred System Plan. The PD, if approved, would certify VCE's 2020 IRP, finding numerous sections were "exemplary." On February 1, 2022, VCE and other LSEs submitted compliance filings updating the CPUC on their incremental procurement.
- **PG&E 2022 ERRA Forecast:** The ALJ issued a Proposed Decision. Parties filed comments on the PD on January 31, 2022, and reply comments on February 3, 2022.
- **RPS Rulemaking:** The CPUC approved D.22-01-025, fining Gexa Energy $352,500 for non-compliance with mandatory reporting requirements of its RPS contracts standard terms and conditions.
- **PG&E's Phase 2 GRC:** On January 14, 2022, a group of parties filed a Settlement Agreement resolving all issues included within the scope related to program and rate design issues for Stage 1 Real-Time Pricing (RTP) Pilots. On January 18, 2022, PG&E filed several motions, including requesting (1) that its Marginal Generation Capacity Cost (MGCC) Study be filed on the same date in this docket as it is required, which was granted by the ALJ in the form of an 8-week extension, and (2) that it be allowed to supplement its testimony in this proceeding with a Declaration on costs, which was also granted. PG&E and CLECA filed a Motion requesting the CPUC to establish a separate expedited schedule to allow a final decision adopting the Joint Stipulation (or otherwise resolving the single carryover issue of material fact about the MGCC

Property Tax Adder) by March 17, 2022. Parties responded to the Motion on February 1, 2022. In addition, an evidentiary hearing on RTP issues was held January 26, 2022, during which a representative from each of the Settling Parties participated in a Settlement Panel.

- **PG&E's Phase 1 GRC:** No updates this month. On November 5, 2021, PG&E filed a motion requesting modifications to the procedural schedule.
- **RA Rulemaking (2023-2024):** On January 19, 2022, the final workshop to develop PG&E's Slice-of-Day proposal and related RA program structural reform was held. On January 21, 2022, parties filed Phase 2 proposals. The Local Capacity Requirement (LCR) Working Group held a meeting on February 2, 2022.
- **PG&E's 2019 ERRA Compliance:** On January 18, 2022, the CCA Parties and TURN filed Phase 2 testimony.
- **PCIA Rulemaking:** On January 27, 2022, the CPUC approved D.22-01-023 targeting improvements to the process of establishing the PCIA in ERRA proceedings.
- **Provider of Last Resort Rulemaking:** A January 27, 2022, email to parties tentatively rescheduled the date of the second workshop to March 7, 2022.
- **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.
- **Utility Safety Culture Assessments**: No updates this month. On December 29, 2021, parties filed reply comments regarding the preliminary scope and schedule provided in the Order Instituting Rulemaking for this rulemaking to develop and adopt IOU safety culture assessments under SB 901.
- **PG&E's 2020 ERRA Compliance:** No updates this month. On October 15, 2021, parties filed a Settlement Agreement resolving disputed issues in this proceeding.
- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month.
- **PG&E Regionalization Plan**: No updates this month. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.
- **Direct Access Rulemaking**: No updates this month. In August, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.
- **RA Rulemaking (2021-2022):** No updates this month. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the RA Rulemaking (2023-2024) closed this proceeding, except to resolve OhmConnect's Petition for Modification.
- **RA Rulemaking (2019-2020):** No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.

Ensuring Summer 2021 Reliability

VCE submitted Advice Letter 11-E on January 5, 2022, detailing information on its implementation of its pilot. On January 25, 2022, PG&E filed a protest of VCE's AL 11-E, to which VCE replied on January 31, 2022. On January 31, 2022, VCE, Polaris and TeMix filed a Petition for Modification of D.21-12-015 to authorize a VCE administrative budget for the pilot, along with a motion to shorten time for comments.

- **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 dynamic rate pilot will receive a "shadow bill." PG&E may bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the existing tariff. 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 to PG&E of $3.25 million for the administration and execution of the three-year pilot.

  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**: VCE's AL 11-E provided information on the implementation of its Agricultural Pumping Dynamic Rate Pilot as required by D.21-12-015. PG&E filed a protest of AL 11-E asserting that the following requirements applied to the pilot:

  - A Request for Proposals process for the independent evaluator of the pilot.
  - Third-party data security review of VCE and its contractors' systems.
  - A services-style contract between PG&E and VCE in order for VCE to have access to pilot funding authorized in D.21-12-015 for payment of customer pumping automation technology, payment of VCE's vendors and payment of VCE's administrative expenses.
  - VCE reporting to the Energy Division.
  - PG&E has the responsibility to develop the distribution rate component in the pilot.

  VCE filed a reply to VCE on January 31, 2022, asserting, among other points, that a services contract between VCE and PG&E is inappropriate and that additional reporting is duplicative.

  VCE, Polaris and TeMix filed a Petition for Modification of D.21-12-015 to increase the budget for this Pilot to ensure that the total budget covers VCE's administrative costs. VCE, Polaris and TeMix also filed a Motion to Shorten Time for comments on the PFM as well as on the Commission's proposed decision resolving the PFM.

- **Analysis**: 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. VCE is seeking approval of its advice letter and petition for modification to facilitate implementation of the pilot.

- **Next Steps**: The proceeding is now closed. PG&E must submit its Tier 2 Advice Letter (in coordination with VCE) on February 4, 2022. VCE must start its pilot by May 1, 2022.
- **Additional Information**: 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 January 27, 2022, the CPUC decided to hold until its February 10, 2022, meeting a vote on the Proposed Decision issued on December 22, 2021 adopting a 2021 Preferred System Plan. The PD, if approved, would certify VCE's 2020 IRP, finding numerous sections were "exemplary." On February 1, 2022, VCE and other LSEs submitted compliance filings updating the CPUC on their incremental procurement.

- **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. After review of the compliance filings, CPUC Staff will bring a Resolution before the Commission specifying the amount of backstop procurement required for a particular IOU on behalf of each LSE for each procurement tranche (2021, 2022, and 2023).

  D.21-06-035 established a new procurement mandate of 11,500 MW of additional zero-emitting or RPS-eligible net qualifying capacity to be procured by 2026 by LSEs through long-term (10 or more years) contracts. It ordered that the resources from Diablo Canyon be replaced with at least 2,500 MW of zero-emitting resources. In addition, it specifies that 2,000 MW of the procurement mandate required for 2026 must be "long-lead-time" (LLT) resources, with half coming from long-duration storage and the other half from zero-emitting resources with an 80% or greater capacity factor, with the Decision pointing to geothermal and biomass as the resources best-suited to meet this category. VCE is permitted to use resources that were not online or in-development and contracted and approved by its Board as of June 30, 2020 to count towards its procurement requirements (i.e., contracts approved by the VCE Board and executed after June 30, 2020, can count towards VCE's procurement mandates). LSEs will ***not*** be given the option to opt out up front from providing their proportional share of the capacity required by D.21-06-035. The February 1, 2023 compliance filing will be the first check on the status of LLT resource procurement. VCE's new obligations and a description of the specific resource requirements for each subcategory of procurement are detailed in the following table. **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.

A pending December 2021 CCA motion for clarification pertains to cost recovery of resources under D.19-11-016, which imposed a 3,300 MW procurement of system RA. Cost recovery and other issues, including RA credits, were to be addressed by a modified Cost Allocation Mechanism (mCAM) that was to be developed by the Commission later in time, but a decision on the mCAM has not yet been issued. Accordingly, the CCAs requested that the CPUC issue an order providing further clarification and interim guidance regarding recently departing load customers.

- **Details**: The PD adopts a 2021 PSP, which 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. It also directs staff to work with the CEC and CAISO to develop a policy-driven sensitivity case designed to test the transmission buildout necessary for a 30 MMT core portfolio with high electrification.

  The PD would result in VCE's 2020 IRP being certified by the CPUC (in contrast to 24 other LSEs that have to file supplemental information). It calls VCE's IRP "exemplary" with respect to the following sections: preferred conforming portfolios, focus on DACs, cost and rate analysis, hydro generation risk management, and long-duration storage development. The PD also maintains a two-year IRP planning cycle (vs. a 3-year cycle) and establishes a September 1, 2022 deadline for the next round of LSE IRPs.

  The PD recommends the adoption of the 38 MMT "Core Portfolio" updated with the 2020 IEPR managed mid-demand forecast and High EV penetration assumption, which 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; Pumped (long-duration) Storage: 1,000 MW; Load Shed DR: 441 MW.

- **Analysis**: The PD would certify VCE's 2020 IRP. It would also adopt a PSP that accelerates the build-out of clean energy resources by adopting a more aggressive GHG reduction target for the electricity sector over the coming decade (i.e., the 38 MMT instead of the 46 MMT used in the 2020 IRP). The PSP is comprised entirely of renewable energy, energy storage, and demand response resources, with no new gas. The PD would extend the due date of VCE's next IRP by four months to September 1, 2022.

- **Next Steps**: The schedule is as follows:
  - VCE's Next IRP Due Date: September 1, 2022 (if the pending PD is adopted)
  - Procurement track: The PD declines to adopt additional procurement requirements. VCE's next compliance filing for its Mid-Term Reliability procurement demonstration is due February 1, 2022.
  - General IRP oversight issues: The PD would maintain the two-year IRP cycle.
  - Preferred System Portfolio Development: The PD may be heard, at the earliest, at the CPUC's February 10, 2022, business meeting.

- **Additional Information**: Proposed Decision 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.

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PG&E 2022 ERRA Forecast

On January 24, 2022, the ALJ issued a Proposed Decision. Parties filed comments on January 31, 2022, and reply comments on February 3, 2022.

- **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**: The PD would approve a 2022 forecast of electric sales and energy procurement revenue requirements of $2.4 billion. It would find the December Update, updated again with the actual year end ERRA-main account balance provides the most accurate forecast for 2022 revenue requirements, and approve the 12-month amortization that was supported by CCAs. Under the December Update adopted in the PD, **the 2022 total PCIA rate for 2017-vintaged customers (i.e., most VCE customers) would fall 59% relative to 2021 to $0.02061/kWh for residential customers and to $0.01980/kWh on a system-average basis.** The PD would also agree 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. The PD would approve a request by CCAs and direct 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. The PD would deny 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.

- **Analysis**: The PD 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. The PD would also improve 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 final decision can be adopted on February 10, 2022.
- **Additional Information**: Proposed Decision (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.

RPS Rulemaking

On January 27, 2022, the CPUC approved D.22-01-025, fining Gexa Energy $352,500 for non-compliance with mandatory reporting requirements of its RPS contracts standard terms and conditions.

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

  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 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**: 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. However, by excluding non-modifiable standard terms and conditions, it found Gexa was out of compliance with the requirement to include the nonmodifiable standard terms and conditions in its contract. Gexa retroactively added the non-modifiable and the modifiable standard terms and conditions to its contract after the Compliance Period had closed. Accordingly, the CPUC imposed a fine for the period that the REC Agreement underlying Gexa's Compliance Report was out of compliance with the applicable RPS program rules. The decision assessed a penalty of $352,500.
- **Analysis**: D.22-01-025 provides another example of how the CPUC has strictly interpreted regulatory compliance requirements and issued sizeable penalties in cases of non-compliance.
- **Next Steps**: VCE's Final 2021 RPS Procurement Plan is due February 17, 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.
- **Additional Information**: D.22-01-025 fining Gexa for RPS non-compliance (approved at January 27, 2022, meeting); 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.

PG&E's Phase 2 GRC

On January 14, 2022, a group of parties filed a Settlement Agreement resolving all of the issues included within the scope related to program and rate design issues for Stage 1 Real-Time Pricing (RTP) Pilots. On January 18, 2022, PG&E filed several motions, including requesting (1) that its Marginal Generation Capacity Cost (MGCC) Study be filed on the same date in this docket as it is required, which was granted by the ALJ in the form of an 8-week extension, and (2) that it be allowed to supplement its testimony in this proceeding with a Declaration on costs, which was also granted. On January 21, 2022, PG&E and CLECA filed a Motion requesting the CPUC to establish a separate expedited schedule to allow a final decision adopting the Joint Stipulation (or otherwise resolving the single carryover issue of material fact about the MGCC Property Tax Adder) by March 17, 2022. Parties responded to the Motion on February 1, 2022. In addition, an evidentiary hearing on RTP issues was held January 26, 2022, during which a representative from each of the Settling Parties participated in a Settlement Panel.

- **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.

- **Details**: The 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.

PG&E/CLECA filed a Motion requesting to establish a separate expedited schedule to allow a final decision adopting the Joint Stipulation (or otherwise resolving the single carryover issue of material fact about the MGCC Property Tax Adder) by March 17, 2022. The ALJ issued a Ruling on January 25, 2022, directing parties to respond by February 1, 2022.

PG&E filed several motions on January 18, 2022. In the first Motion, PG&E requested the Marginal Generation Capacity Cost (MGCC) Study be filed on the same date in this docket as it is required to be filed in A.20-10-011, the proceeding for the real-time commercial electric vehicle rate (DAHRTPCEV). PG&E further requested an ALJ Ruling setting dates for MGCC related testimony and hearings for this proceeding on a combined basis with the same issues in the DAHRTP-CEV case. A January 25, 2022, email from PG&E indicated that the ALJ approved an 8-week extension. In the second Motion, PG&E requested to supplement its testimony in this proceeding with the Declaration on costs for the Residential Stage 1 RTP pilot.

- **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. PG&E/CLECA reply comments are due February 7, 2022. PG&E's MGCC Study is due March 15, 2022., followed by opening briefs in February 2022, reply briefs in March 2022, a proposed decision in June 2022, and a decision in July 2022.
- **Additional Information**: 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); Docket No. A.19-11-019.

PG&E Phase 1 GRC

No updates this month. On November 5, 2021, PG&E filed a motion requesting modifications to the procedural schedule.

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

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

In Track 2, public participation hearings are scheduled for November 2022, and intervenor testimony is due November 14, 2022. A proposed decision is anticipated in Q2 2023, and a final decision is anticipated in Q3 2023.

- **Additional Information**: 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 January 19, 2022, the final workshop to develop PG&E's Slice-of-Day proposal and related RA program structural reform was held. On January 21, 2022, parties filed Phase 2 proposals. The Local Capacity Requirement (LCR) Working Group held a meeting on February 2, 2022.

- **Background**: In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops. The PG&E Slice of Day Framework will establish RA requirements based on a "slice-of-day" framework, which seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours. The proposal also attempted to ensure there is sufficient energy on the system to charge energy storage resources. The proposed framework would establish RA requirements for multiple slices-of-day across seasons and would establish a counting methodology to reflect an individual resource's ability to produce energy during each respective slice (e.g., six four-hour periods of the day).

  The OIR establishes two tracks to this rulemaking. First, the ongoing major RA structural reforms being considered through a workshop process based on PG&E's "slice-of-day" proposal (previously referred to as "Track 3B.2" in the R.19-11-009 RA rulemaking), is now the "Reform Track" in this rulemaking. All other issues relating to RA procurement obligations and program implementation details will be separated into an "Implementation Track." The Implementation Track will address Local RA requirements for 2023-2026, Flexible RA requirements for 2023-2024, potential modifications to the Central Procurement Entity structure and process, potential modifications to the Planning Reserve Margin, potential modifications to Qualifying Capacity Counting Conventions and Effective Load Carrying Capability (i.e., how different types of resources are counted and credited for RA compliance), and refinements to the RA program.

  The CPUC authorized the creation of a BTM Counting Convention Working Group in D.21-06-029, which was the RA decision that adopted local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the RA program. The final product of the working group will be a report that covers both a set of eight issues identified by the CPUC and explicit proposals.

- **Details**: The 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 Workshop Report to be submitted into the RA proceeding in February 2022 now that workshops to develop this proposal have been completed. The Implementation Track is sub-divided into Phases 1, 2, and 3:

  - Phase 1 of the Implementation Track will consider critical modifications to the CPE structure. Phase 1 is expected to conclude by March 2022.

  - 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.

- **Analysis**: This proceeding will determine VCE's RA obligations and applicable RA rules for the 2023-2024 compliance periods. It will also be the forum for determining major RA structural reforms, such as those being discussed related to PG&E's "slice-of-day" proposal. The workshop process on PG&E's Slice of Day proposal could result in major changes to the RA program structure beginning in the 2024 RA compliance year. The new structure would seek to ensure load (including energy storage charging) will be met in all hours of the day, not just during gross peak demand hours and would move RA from a monthly compliance obligation to a seasonal obligation. The details of the framework would be further fleshed out through the workshop process and need to be approved by the CPUC in 2022.
- **Next Steps**: The procedural schedule for the ongoing tracks and working groups are as follows:

  Phase 1

  - Proposed Decision: February 2022
  - Final Decision: March 2022

  Phase 2

  - Energy Division's loss of load expectation (LOLE) study and proposal: February 1, 2022
  - Workshop on proposals: February 4, 2022
  - Comments on workshop/proposals: February 14, 2022
  - Reply comments on workshop/proposals: February 24, 2022
  - Proposed Decision: May 2022
  - Final Decision: June 2022

  Reform Track

  - Informal comments: February 4, 2022
  - Workshop report: February 2022

  BTM Counting Convention Working Group meeting dates (9am-1pm): February 8, 2022; February 22, 2022.

- **Additional Information**: 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.

PG&E's 2019 ERRA Compliance

On January 18, 2022, intervenors filed Phase 2 testimony.

- **Background**: Phase 1 has been resolved. The September 7, 2021, Ruling consolidated the Phase 2 ERRA compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:
  - What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on

this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 PSPS events?

- Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.

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: According to the Joint IOUs' proposal, only energy-related distribution rates would be used to determine the unrealized revenue from end-use customers de-energized during PSPS events, ignoring several additional retail rates and other sources of revenue that are reduced by PSPS events.

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 describes 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 explain 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 recommend the following:

1. 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.
2. Each IOU should make a full accounting of the balancing accounts implicated by the total unrealized retail revenue.
3. 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.
4. 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. The November 12, 2021, Ruling clarified that CCAs may dispute the Joint IOUs' unrealized revenue methodology and conduct discovery and propose alternative methodologies, such as those that would fairly consider unrealized revenues from utility-owned generation that had not been bid into the CAISO market unlike the Joint IOUs' proposal.

- **Next Steps**: IOU rebuttal testimony is due February 15, 2022, and a Joint Case Management Statement is due February 25, 2021.

- **Additional Information**: 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.

PCIA Rulemaking

On January 27, 2022, the CPUC approved D.22-01-023 targeting improvements to the process of establishing the PCIA in ERRA proceedings.

- **Background**: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity. Phase 2 relied primarily on a working group process to further develop a number of PCIA-related proposals. Three workgroups examined three issues: (1) issues with the highest priority: Benchmark True-Up and Other Benchmarking Issues; (2) issues to be resolved in early 2020: Prepayment; and (3) issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction.

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

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

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

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

- **Details**: D.22-01-023 modifies 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.

  The PD would keep 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.
- **Analysis**: D.22-01-023 makes improvements to the annual ERRA process and CCA access to pertinent IOU data.
- **Next Steps**: D.21-05-030 identified the following next steps:
  - **February 2022**: After approval of the joint methodology advice letter, IOUs will inform LSEs of their potential Voluntary Allocation shares.
  - **May 2022**: IOUs and LSEs complete the process of determining interest in Allocation elections.
  - **June 2022**: Each IOU confirms Voluntary Allocations and propose Market Offers in their 2022 RPS Procurement Plans. LSEs request approval for Voluntary Allocations in their 2022 RPS Procurement Plans.
- **Additional Information**: D.22-01-023 on Phase 2 (approved January 27, 2021); Ruling requesting comments on PCIA forecasting data access (November 5, 2021); Ruling requesting comments (September 17, 2021); CalCCA Application for Rehearing of D.21-05-030 (June 23, 20210: D.21-05-030 on PCIA Cap and Portfolio Optimization (May 24, 2021); D.21-03-051 granting petition to modify D.17-08-026 (March 26, 2021); Amended Scoping Memo and Ruling (December 16, 2020); 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.

Provider of Last Resort Rulemaking

A January 27, 2022, email to parties tentatively rescheduled the date of the second workshop to March 7, 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 describes the issues that are within scope in the proceeding and the procedural schedule going forward, although most of the procedural dates currently lack specificity. Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.

  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**: A forthcoming ruling will provide additional details on comment and reply comment deadlines, as well as a workshop agenda for the March 7, 2022 workshop.

- **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 second workshop in Phase 1 has been tentatively rescheduled for March 7, 2022. A forthcoming ruling will provide an updated schedule for comments and reply comments
- **Additional Information**: 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.

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.

Utility Safety Culture Assessments

No updates this month. On December 29, 2021, parties filed reply comments regarding the preliminary scope and schedule provided in the Order Instituting Rulemaking for this rulemaking to develop and adopt IOU safety culture assessments under SB 901.

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

- **Details**: This proceeding will implement the statutory requirements of SB 901 relating to the Commission's assessment of safety culture for regulated utilities. It will examine what methodologies should be employed in the safety culture assessments to ensure results are comparable across IOUs and can measure changes in IOU safety culture over time. It will also consider adopting the process and framework to oversee safety culture assessments of gas utilities and gas storage operators, in addition to electrical corporations as required by SB 901. It will consider requiring that IOUs implement specific safety management practices to improve safety culture through adoption of a Safety Management System standard, consider adopting a maturity model to use in safety culture assessments, and determine accountability metrics.

  No CCA parties filed comments or reply comments on the Order Instituting Rulemaking.

- **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 prehearing conference is expected to be held, followed by the issuance of a Scoping Memo and Ruling that will identify the issues in scope in this proceeding and the procedural schedule.

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

PG&E 2020 ERRA Compliance

No updates this month. On October 15, 2021, parties filed a Settlement Agreement resolving disputed issues in this proceeding.

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

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

  PG&E's procurement costs recorded across the portfolio were $158.8 million higher than forecasted, allegedly due to higher-than-forecast RPS-eligible contracts, as offset by higher than forecast retained RPS and retained RA, as well as lower than forecast fuel costs for UOG facilities. Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity, RA Activity, Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, GHG Costs, and Miscellaneous Costs.

PG&E has redacted as confidential its 2020 actual and forecast costs for these categories, so it is unclear from the public filing what the magnitude is regarding the difference between actual and forecast costs for each category.

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

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

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

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

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

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

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

- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022 and 2023.

- **Next Steps**: A PD is anticipated for Q1 2022.
- **Additional Information**: Joint Motion for Adoption of Settlement Agreement (October 15, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

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

No updates this month.

- **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. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.

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

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

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

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

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

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

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

Direct Access Rulemaking

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

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

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

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

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

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

  CalCCA's August response argued that:

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

- **Analysis**: This proceeding determined the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California. D.21-06-033 recommending against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.

- **Next Steps**: The only remaining item to be addressed in this proceeding is the Application for Rehearing 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.

RA Rulemaking (2021-2022)

No updates this month. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the successor RA rulemaking, R.21-10-002, closed this proceeding, except to resolve OhmConnect's Petition for Modification.

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

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

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

  Track 3B.2 (Ongoing, 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 says that the change is needed to create the room for growth envisioned in D.20-06-031 and meet the requirements of the Governor's Emergency Proclamation ordering state energy agencies to expedite and expand DR programs to reduce the likelihood of future rotating power outages.

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

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

- **Next Steps**: A proposed decision addressing OhmConnect, Inc.'s petition for modification and closing this proceeding is expected to be issued next.

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

RA Rulemaking (2019-2020)

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

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

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

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

In Track 3, D.19-06-026 adopted CAISO's recommended 2020-2022 Local Capacity Requirements and CAISO's 2020 Flexible Capacity Requirements and made no changes to the System capacity requirements. It established an IOU load data sharing requirement, whereby each non-IOU LSE (e.g., CCAs) will annually request data by January 15 and the IOU will be required to provide it by March 1. It also adopted a "Binding Load Forecast" process such that an LSE's initial load forecast (with CEC load migration and plausibility adjustments based on certain threshold amounts and revisions taken into account) becoming a binding obligation of that LSE, regardless of additional changes in an LSE's implementation to new customers.

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

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

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

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

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

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

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

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BTM	Behind the Meter
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CTC	Competition Transition Charge
DA	Direct Access
DWR	California Department of Water Resources
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
EUS	Essential Usage Study
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
LSE	Load-Serving Entity
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
PD	Proposed Decision
PG&E	Pacific Gas & Electric
PFM	Petition for Modification
PCIA	Power Charge Indifference Adjustment

POLR	Provider of Last Resort
PSPS	Public Safety Power Shutoff
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act of 1978 (federal)
QC	Qualifying Capacity
QF	Qualifying Facility under PURPA
RA	Resource Adequacy
RDW	Rate Design Window
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SED	Safety and Enforcement Division (CPUC)
SDG&E	San Diego Gas & Electric
TCJA	Tax Cuts and Jobs Act of 2017
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)