

## VALLEY CLEAN ENERGY ALLIANCE

### Staff Report – Item 8

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To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: March 10, 2022

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Please find attached Keyes & Fox's February 2022 Regulatory Memorandum dated March 2, 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 March 2, 2022.

# Valley Clean Energy Alliance

## Regulatory Monitoring Report

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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: March 2, 2022

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### 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, Polaris and TeMix filed a Petition for Modification of D.21-12-015 to authorize a VCE administrative budget for VCE's Agricultural Pumping Dynamic Rate Pilot, along with a motion to shorten time for comments. The Public Advocates Office (PAO) filed a response, to which VCE replied. In addition, PG&E filed AL 6495-E on VCE's Pilot, and VCE, Polaris and TeMix filed a Protest of PG&E AL 6495-E.
- **IRP Rulemaking:** The CPUC issued D.22-02-004, adopting a 2021 Preferred System Plan and certifying VCE's 2020 IRP, finding numerous sections were "exemplary." VCE's next IRP is due November 1, 2022. CPUC, CEC and CAISO held a workshop to discuss approaches for examining the environmental and land use implications of potential resource portfolios to meet SB 100. The CEC also hosted a workshop providing an overview of the strategic plan called for in AB 525, which directed it to evaluate and quantify the maximum feasible capacity of offshore wind to achieve reliability, ratepayer, employment, and decarbonization benefits and establish megawatt offshore wind planning goals for 2030 and 2045.
- **PG&E 2022 ERRA Forecast:** On February 11, 2022, the CPUC issued D.22-02-002, resolving all issues and closing the proceeding. The final system average PCIA rate for the 2017 vintage is \$0.01897/kWh.
- **RPS Rulemaking:** On February 1, 2022, the Commission issued D.22-01-025, finding that Gexa Energy California LLC failed to comply with the requirement to include certain nonmodifiable standard terms and conditions in its RPS procurement contract and imposed a penalty of \$352,500. On February 17, 2022, VCE and other retail sellers filed their final 2021 RPS Procurement Plans in compliance with D.22-01-004.
- **PG&E's Phase 2 GRC:** The ALJ issued a Proposed Decision on the issue of the property tax adder. For reference, in January, PG&E and CLECA filed a Motion requesting the CPUC to

establish a separate expedited schedule to allow a final decision resolving the single carryover issue of material fact about the MGCC Property Tax Adder by March 17, 2022.

- **PG&E's Phase 1 GRC:** PG&E and Caltrain submitted a joint report on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco. The ALJ issued a Ruling scheduling public participation hearings on three days in March 2022, with the first hearing held on March 1, 2022. TURN, PG&E, and PAO filed a Motion requesting modifications to the Track 1 schedule. PG&E filed an update to its forecast for wildfire mitigation activities, concurrent with its service of its 2022 Wildfire Mitigation Plan. PG&E hosted a workshop to provide an overview of the updates provided in its February 25, 2022, supplemental testimony.
- **RA Rulemaking (2023-2024):** The ALJ issued a Proposed Decision that would make modifications to the RA central procurement entity (CPE) structure, including changes to encourage LSEs to self-show resources. Parties filed comments and reply comments on Phase 2 proposals. The ALJ issued a Ruling providing Energy Division's loss of load expectation study and the CEC's Qualifying Capacity of Supply-Side Demand Response Working Group Report. The workshop report was filed on the PG&E "slice-of-day" proposal that seeks to ensure load will be met in all hours of the day.
- **PG&E's 2019 ERRA Compliance:** The Joint IOU rebuttal testimony was filed February 15, 2022, and a Joint Case Management Statement was submitted February 25, 2022.
- **Provider of Last Resort Rulemaking:** The ALJ issued a Ruling confirming that the second workshop in Phase 1 will take place on March 7, 2022, distributing an agenda for the workshop, and setting forth questions on which parties may comment during the workshop, as well as in written comments after the workshop.
- **RA Rulemaking (2019-2020):** The CPUC issued D.22-02-008, denying Western Power Trading Forum's Application for Rehearing of D.20-06-002, which adopted implementation details for the central procurement of multi-year local RA procurement. One application for rehearing remains the only outstanding item to be addressed in this proceeding, which is now closed.
- **Utility Safety Culture Assessments:** The CPUC's Safety Policy Division notified stakeholders of plans to hold an informational workshop on March 11, 2022.
- **PCIA Rulemaking:** No updates this month. On January 27, 2022, the CPUC approved D.22-01-023 targeting improvements to the process of establishing the PCIA in ERRA proceedings.
- **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.
- **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.

## Ensuring Summer 2021 Reliability

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 VCE's Agricultural Pumping Dynamic Rate Pilot (Pilot), along with a motion to shorten time for comments. The Public Advocates Office (PAO) filed a response to the motion on February 9, 2022, to which VCE replied on February 17, 2022. On February 4, 2022, PG&E filed AL 6495-E on the Pilot and on February 24, 2022, VCE, Polaris and TeMix (Pilot Partners) filed a Protest of PG&E AL 6495-E.

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

D.21-03-056 instituted modifications to the planning reserve margin (PRM), effectively increasing the PRM beginning summer 2021 from 15% to 17.5%. For 2021, this results in a minimum target of incremental procurement of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E. The net costs associated with this incremental procurement would be shared by all customers (including CCA customers) in each IOU's service territory. It also authorized the IOUs to implement a Flex Alert paid media campaign program to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid, adopts modifications and expansions to the Critical Peak Pricing (CPP) program, and established an emergency load reduction program.

D.21-12-015 approved VCE's dynamic rate Pilot for three years (2022-2024) and directed that it start no later than May 1, 2022. VCE's Pilot will test whether agricultural irrigation pumping customers, which consume on average 18% of VCE's total annual load, can shift load to more optimal times of the day, thereby saving money, reducing burden to the grid and reducing GHG impacts. Customers participating in VCE's Pilot will receive a "shadow bill." PG&E will continue to bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the Pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the 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 of \$3.25 million for the pumping automation technology, pricing platform and vendor fees and PG&E's administration 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:** The Pilot Partners filed a Petition for Modification (PFM) of D.21-12-015 to increase the budget for this Pilot to ensure that the total budget covers VCE's administrative costs. The Pilot Partners also filed a Motion to Shorten Time for comments on the PFM as well as on the Commission's proposed decision resolving the PFM. PAO's Response recommended that the Motion be denied, arguing that the more time was needed to comment on increases to ratepayer costs. The Pilot Partners' reply stated that its requested relief sought in the PFM is not new, as it has consistently expressed the need to cover VCE's administrative expenses. PAO also issued a discovery request to the Pilot Partners relating to such administrative costs and VCE's plans for allocation of the Pilot budget, to which the Pilot Partners replied on February 24, 2022.

The Pilot Partners also filed a Protest of PG&E's AL 6495-E. The Pilot Partners objected to the pricing methodology proposed by PG&E, saying it is inconsistent with the UNIDE framework

because it does not employ smooth scarcity pricing/continuous functions to determine the delivery component and therefore is inconsistent with the explicit direction of D.21-12-015 to test dynamic rates. Furthermore, the Pilot Partners argued that the differentials between peak and off-peak AL 6495-E are too small to effectively test the impacts of dynamic pricing. The Pilot Partners objected to PG&E's attempt to establish various participation rules for the Pilot, including determining eligibility for various types of net energy metering (NEM) customers and other participation requirements.

- **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 and VCE's ability to pay its vendors. In its advice letter, PG&E has asserted control over various elements of the Pilot that were not authorized by the Commission or are inconsistent with the Commission's Decision. PG&E has also asserted the need for a VCE-PG&E contract which inappropriately treats VCE as PG&E's service provider. VCE is seeking approval of its advice letter and PFM to facilitate implementation of the Pilot.
- **Next Steps:** The Commission's Energy Division is expected to resolve VCE's Advice Letter 11-E this month. PG&E's reply to the Pilot Partners' Protest is due March 1, 2022. Responses and protests to the PFM are due March 2, 2022. If permission is granted for filing, the Pilot Partners' reply to any such responses or protests will be due March 14, 2022. The Commission's proposed decision on the PFM will be issued thereafter, which will be subject to party comments and a Commission vote. VCE must start its Pilot by May 1, 2022.
- **Additional Information:** VCE, Polaris, and TeMix [Protest](#) of PG&E [AL 6495-E](#) (February 24, 2022); VCE, Polaris, and TeMix [Reply](#) to PAO Response (February 18, 2022); 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 February 15, 2022, the CPUC issued D.22-02-004, adopting a 2021 Preferred System Plan and certifying VCE's 2020 IRP, finding numerous sections were "exemplary." VCE's next IRP is due November 1, 2022. On February 22, 2022, the CPUC, CEC and CAISO held a workshop to discuss approaches for examining the environmental and land use implications of potential resource portfolios to meet SB 100. The CEC also hosted a workshop on March 3, 2022, providing an overview of the strategic plan called for in AB 525, which directed it to evaluate and quantify the maximum feasible capacity of offshore wind to achieve reliability, ratepayer, employment, and decarbonization benefits and establish megawatt offshore wind planning goals for 2030 and 2045.

- **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 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.

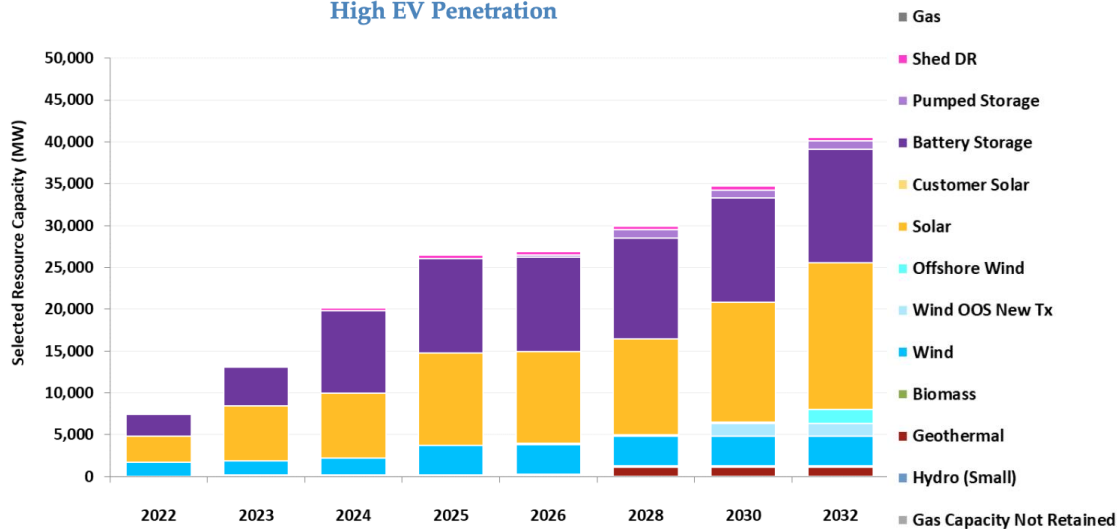
A pending December 2021 CCA motion for clarification pertains to cost recovery of resources under D.19-11-016, which imposed a 3,300 MW procurement of system RA. Cost recovery and other issues, including RA credits, were to be addressed by a modified Cost Allocation Mechanism (mCAM) that was to be developed 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:** D.22-02-004 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, which is a more aggressive GHG reduction portfolio than the 46 MMT portfolio used in 2020 IRPs. 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 D.22-02-004 certifies VCE’s 2020 IRP (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. It also maintains the existing two-year IRP planning cycle (vs. the proposed 3-year cycle) and establishes a November 1, 2022 deadline for the next round of LSE IRPs.

D.22-02-004 results in the following new resource build by 2032, by technology: Gas: 0 MW; Biomass: 134 MW; Geothermal: 1,160 MW; Wind: 3,531 MW; Wind (New Transmission): 1,500 MW; Offshore Wind: 1,708 MW; Utility-Scale Solar: 17,506 MW; Battery Storage: 13,571 MW; Long-duration Storage: 1,000 MW; Load Shed DR: 441 MW. The following figure illustrates future resource additions under the PSP.

Figure 5. 38 MMT Core with 2020 IEPR Demand and High EV Penetration



- Analysis:** D.22-02-004 certified VCE’s 2020 IRP. It also adopts 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. It also extended the due date of VCE’s next IRP to November 1, 2022.
- Next Steps:** VCE’s next IRP is November 1, 2022. The CPUC will issue a Ruling by June 15, 2022, providing additional direction and detail on the requirements for LSE 2022 IRPs.
- Additional Information:** [D.22-02-004](#) adopting 2021 Preferred System Plan (December 22, 2021); CCA [Motion](#) for Clarification (December 13, 2021); [D.21-06-035](#) establishing a 11,500 MW by 2026 procurement mandate (June 24, 2021); [D.21-02-028](#) recommending portfolios for CAISO’s 2021-2022 TPP (February 17, 2021); [D.20-12-044](#) establishing a backstop procurement process (December 22, 2020); [Scoping Memo and Ruling](#) (September 24, 2020); [Resolution E-5080](#) (August 7, 2020); [Order Instituting Rulemaking](#) (May 14, 2020); Docket No. [R.20-05-003](#).

## PG&E 2022 ERRA Forecast

On February 11, 2022, the CPUC issued D.22-02-002, resolving all issues and closing the proceeding.

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

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

PG&E’s Fourth Supplemental Testimony included both an “October Update” and a “December Update.” A group of CCA parties recommended in comments that the CPUC adopt the proposed forecasted revenue requirements and associated rates from the December Update and requested the rates be implemented by February 1, 2022. The CCA parties said that adopting the December update would reduce likely volatility between 2022 and 2023 rates and that adoption of an

October Update would clearly violate State law and Commission precedent. The CCAs noted that PG&E's forecasted costs to serve load in 2022 are 66.5% higher than in 2021.

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

- Details:** D.22-02-002 approves a 2022 forecast of electric sales and energy procurement revenue requirements of \$2.4 billion, effective in rates on March 1, 2022. It finds the December Update, updated again with the actual year end ERRA-main account balance provides the most accurate forecast for 2022 revenue requirements, and approves the 12-month amortization that was supported by CCAs. Under the December Update adopted in D.22-02-002, **the 2022 total PCIA rate for 2017-vintaged customers (i.e., most VCE customers) will fall 59% relative to 2021 to \$0.01969/kWh for residential customers and to \$0.01897/kWh on a system-average basis.** It also agrees with the Joint CCAs and DACC that all customers who were financially responsible for the ERRA-PCIA Financing Subaccount (ERRA-PFS) balance should be entitled to the appropriate credit and direct PG&E to transfer the \$95 million ERRA-PFS credit for 2022 to the 2020 vintage subaccount. It approves a request by CCAs and directs PG&E to include the confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding. D.22-02-002 denies without prejudice the CCA's request to direct PG&E to provide data demonstrating its future role as a CPE in future ERRA forecast proceedings.
- Analysis:** D.22-02-002 results in a 59% reduction to VCE's PCIA rates in 2022 compared to 2021. While the PCIA rate will fall substantially in 2022 for VCE customers, the non-RPS benchmarks that contributed to the reduction in the PCIA in 2022 could result in the opposite effect in 2023. That is, the same high benchmarks that helped reduce the 2022 year's forecast case may be too high compared to next year's actuals, which would create large PABA undercollection balances for 2023 rates. The change in the PCIA rate from the December Update will help mitigate such a swing in rates in 2023. D.22-02-002 also improves transparency by approving the CCAs' request for PG&E to provide confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding.
- Next Steps:** The proceeding is now closed.
- Additional Information:** [D.22-02-002](#) (January 24, 2022); [Ruling](#) modifying procedural schedule (January 14, 2022); [Ruling](#) directing PG&E to provide amortization scenarios (December 17, 2021); [Scoping Memo and Ruling](#) (August 11, 2021); [Notice](#) of Prehearing Conference (July 15, 2021); [Application](#) (June 1, 2021); Docket No. [A.21-06-001](#).

## RPS Rulemaking

On February 1, 2022, the Commission issued D.22-01-025, finding that Gexa failed to comply with the requirement to include certain nonmodifiable standard terms and conditions in its RPS procurement contract. On February 17, 2022, VCE and other retail sellers filed their final 2021 RPS Procurement Plans in compliance with D.22-01-004.

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

D.22-01-004 directed VCE to include in its Final 2021 RPS Procurement Plan due February 17, 2022, a discussion "explain[ing] how mid-term reliability procurement obligations impact RPS compliance requirements and how they are included in the quantitative assessment" and update



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

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

- Details:** In D.22-01-025, the CPUC found that Gexa, an ESP that is currently not serving any load, met its procurement quantity requirement for the Compliance Period 2014-2016 and retired sufficient RECs. The decision found, however, that by excluding certain non-modifiable standard terms and conditions in a RPS procurement contract with NextEra Energy Marketing, LLC, Gexa was out of compliance with the requirements in D.08-04-009, D.10-03-021, D.11-01-025, and D.13-11-024. The non-modifiable standard terms and conditions relate to transfer of RECs, tracking of RECs in WREGIS and compliance with applicable law. Gexa retroactively added the non-modifiable and certain modifiable standard terms and conditions to its contract after the Compliance Period had closed. Despite this, the CPUC imposed a fine of \$352,500 for the period that the REC Agreement underlying Gexa's Compliance Report was out of compliance with the applicable RPS program rules. .
- Analysis:** VCE has now met its 2021 RPS Procurement Plan requirements. D.22-01-025 provides another example of how the CPUC has strictly interpreted RPS compliance requirements and issued sizeable penalties in cases of non-compliance. The Commission refused to permit retroactive RPS procurement contract amendment to comply with the requirement to include the nonmodifiable terms and conditions. In addition, the Commission's finding that Gexa complied with the long-term contract requirement warned was limited to the decision, and provided "in the future, we shall not accept any long-term contract that fails to demonstrate the required term of at least ten years."
- Next Steps:** VCE's draft 2022 RPS Procurement Plan will be due in late spring or summer 2022 (exact date to be determined), and its RPS Compliance Report will be due August 1, 2022. R.18-07-003 is expected to close in September 2022, with a new proceeding to be opened to address RPS issues going forward.
- Additional Information:** [VCE's Final 2021 RPS Procurement Plan](#) (February 17, 2022); [D.22-01-025](#) fining Gexa for RPS non-compliance (February 1, 2022); [D.22-01-004](#) on draft 2021 RPS Procurement Plans (January 18, 2022); [D.21-12-032](#) modifying the ReMAT tariff (December 16, 2021); [D.21-11-029](#) amending RPS confidentiality rules (November 19, 2021); [Petition for Modification](#) of D.20-10-005 on ReMAT pricing (October 8, 2021); [Ruling](#) aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26, 2021); [Ruling](#) establishing issues and schedule for 2021 RPS Procurement Plans (March 30, 2021); [D.21-01-005](#) directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); [Ruling](#) on [Staff proposal](#) aligning RPS/IRP filings (September 18, 2020); [Scoping Ruling](#) (November 9, 2018); Docket No. [R.18-07-003](#).

## PG&E's Phase 2 GRC

On February 11, 2022, the ALJ issued a Proposed Decision on the issue of the property tax adder. For reference, in January, PG&E and CLECA filed a Motion requesting the CPUC to establish a separate expedited schedule to allow a final decision resolving the single carryover issue of material fact about the MGCC Property Tax Adder by March 17, 2022.

- **Background:** PG&E's 2020 Phase 2 General Rate Case (GRC) addresses marginal cost, revenue allocation and rate design issues covering the next three years. D.21-11-016 largely adopted PG&E's proposed marginal costs and methodologies for deriving them but adopted marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association. It also adopted, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; Economic Development Rate (EDR) settlement; agricultural rate design; C&I rate design) and revenue allocation.

With respect to CCA issues, the adopted EDR settlement noted that PG&E and the Joint CCAs agreed to create a collaborative process "to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR." D.21-11-016 also approved the agricultural rate design settlement that proposed that the unbundling of the PCIA from the generation component of bundled rates be designed as a flat PCIA rate, not differentiated by season or TOU period, consistent with the PCIA rate design for DA and CCA customers. The PCIA rate for bundled customers will use the most recent vintage of the PCIA rate. Finally, D.21-11-016 approved the revenue allocation settlement, including its proposal that before allocating generation revenue, instead of including the PCIA revenue in the overall generation revenue requirement, PCIA revenue will be removed from each customer class's revenue at present rates based on the most recent vintage PCIA rates. Then, PG&E will use the adopted allocation for generation to allocate the PCIA revenue requirement to customer classes.

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

- **Eligibility:** PG&E's bundled customers who are eligible for the B-20, B-6 and E-ELEC rates may participate on an opt-in basis. CCAs will need to affirmatively decide to participate in the Stage 1 Pilots for their customers to be eligible. PG&E agrees to work with its twelve CCAs to seek agreement from one or two of them to participate in the Stage 1 Pilots, if possible.
- **Duration:** Stage 1 Pilots shall have a duration of 24 months, subject to potential extension.
- **Enrollment:** PG&E will make its best efforts to program and make available for enrollment the three Stage 1 RTP rates by October 1, 2023.
- **Pricing:** The RTP element of the Stage 1 Pilot RTP rates will replace the generation component of the customer's otherwise applicable rate schedule. The remaining transmission, distribution, Public Purpose Program and other charges and taxes remain the same as the otherwise applicable underlying rate. The generation component to be used in the Stage 1 Pilots' RTP rates will include: (1) a Marginal Energy Charge, (2) a Marginal Generation Capacity Cost, and (3) a Revenue Neutral Adder (designed to make the forecasted annual generation revenue collected under the three Stage 1 Pilot RTP rates revenue neutral to the base schedule). Residential customers would have 1 year bill protection. There would be a limited amount of participation incentives as well.

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

- **Details:** In January, PG&E/CLECA filed a Motion requesting to establish a separate expedited schedule to allow a final decision adopting their Joint Stipulation, or otherwise resolving the single carryover issue of material fact about the MGCC Property Tax Adder, by March 17, 2022. The February 11, 2022, Proposed Decision adopts the PG&E/CLECA Joint Stipulation on the appropriate calculation for the property tax adder to be included in the marginal generation capacity cost for new customer rates effective June 1, 2022.
- **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. Comments and replies on the Proposed Decision are due March 3, 2022, and March 8, 2022, respectively, with a CPUC vote on the Proposed Decision occurring as early as March 17, 2022. PG&E's MGCC Study is due March 15, 2022, and it will file its non-NEM export compensation proposal for BEV on March 24, 2022, followed by a meet-and-confer on March 29, 2022.
- **Additional Information:** [Proposed Decision](#) on property tax adder (February 11, 2022); [Ruling](#) on timing to respond to PG&E/CLECA Motion (January 25, 2022); [Motion](#) by PG&E/CLECA to establish a separate expedited schedule (January 21, 2022); PG&E [Motion](#) on MGCC Study (January 18, 2022); PG&E [Motion](#) (January 18, 2022); [Motion](#) to Adopt Settlement Agreement (January 18, 2022); [D.21-11-016](#) on revenue allocation and rate design (November 19, 2021); [Amended Scoping Memo and Ruling](#) (August 25, 2021); [Ruling](#) bifurcating RTP issues into separate track (February 2, 2021); [D.20-09-021](#) on EUS budget (September 28, 2020); [Exhibit \(PG&E-5\)](#) (May 15, 2020); [Scoping Memo and Ruling](#) (February 10, 2020); [Application, Exhibit \(PG&E-1\): Overview and Policy, Exhibit \(PG&E-2\): Cost of Service, Exhibit \(PG&E-3\): Revenue Allocation, Rate Design and Rate Programs, and Exhibit \(PG&E-4\): Appendices](#) (November 22, 2019); Docket No. [A.19-11-019](#).

## PG&E Phase 1 GRC

On February 1, 2022, PG&E and Caltrain submitted a joint report on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco. On February 2, 2022, the ALJ issued a Ruling scheduling public participation hearings on three days in March 2022. On February 16, 2022, TURN, PG&E, and PAO filed a Motion requesting modifications to the Track 1 schedule. On February 25, 2022, PG&E filed an update to its forecast for wildfire mitigation activities, concurrent with its service of its 2022 Wildfire Mitigation Plan. The first public participation hearing was held March 1, 2022. PG&E hosted a workshop on March 2, 2022 to provide an overview of the updates provided in PG&E's February 25, 2022, supplemental testimony.

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

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

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

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

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

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

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

The Motion filed by TURN, PG&E, and PAO requests an extension of time for intervenor testimony responding to PG&E's February 25, 2022, update to its forecast for wildfire mitigation activities, as well as moving evidentiary hearings from May to June 2022, among other changes to the procedural schedule. On February 22, 2022, Joint CCAs notified the ALJ they intended to file a response to the Motion strongly opposing the Motion's request that the CPUC impose a new deadline for discovery directed at PG&E's Opening Testimony and disagreed with the Motion's characterization that the Joint CCAs consented to this limitation on discovery.

On February 25, 2022, PG&E filed an update to its forecast for wildfire mitigation activities related to its announced plans to underground 10,000 miles of transmission lines.

- **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 on March 10, 2022, and March 22, 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:** PG&E [Affordability Metrics Report](#) (February 23, 2022); ALJ [Ruling](#) on Public Participation Hearings (February 2, 2022); PG&E/Caltrain Report (February 1, 2022); [Ruling](#) denying PG&E Motion to submit supplemental testimony (November 12, 2021); [Motion](#) of PG&E to modify procedural schedule (November 5, 2021); [Scoping Memo and Ruling](#) (October 1, 2021); [PG&E Application](#) (June 30, 2021); Docket No. [A.21-06-021](#).

## RA Rulemaking (2023-2024)

On February 10, 2022, the ALJ issued a Proposed Decision (PD) that would make modifications to the RA central procurement entity (CPE) structure, including revisions to the requirements for self-shown local resources, revisions to the CPE's solicitation selection criteria, and revisions to the CPE procurement timeline. On February 14, 2022, and February 24, 2022, respectively, parties filed comments and reply comments on Phase 2 proposals. On February 18, 2022, the ALJ issued a Ruling providing Energy Division's loss of load expectation (LOLE) study and the California Energy Commission's (CEC) Qualifying Capacity of Supply-Side Demand Response Working Group Report. On February 28, 2022, a workshop report was filed on the PG&E "slice-of-day" proposal that has been discussed and further refined through a series of workshops in recent months.

- **Background:** In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops.

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

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

- Phase 1 of the Implementation Track 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
- **Details:** The PD would make modifications to the RA central procurement entity (CPE) structure, including revisions to the requirements for self-shown local resources, revisions to the CPE's solicitation selection criteria, and revisions to the CPE procurement timeline. The PD would mitigate several potential disincentives to LSEs self-showing local RA resources for no compensation. The PD also states that given the shortfalls in the PG&E CPE's procurement process and the low participation rates in the CPE solicitation process, the Commission wants to

better understand why LSEs are electing not to bid or self-show resources to the CPE. Accordingly, if the PD is approved, LSEs that decline to self-show or bid will be required to submit a justification with their year-ahead RA filing explaining their rationale for informational purposes for the Commission. The PD would allow CPEs to procure outside of the annual solicitation process if there are deficiencies following the CPEs' annual solicitation and only to cover those deficiencies. The PD allows IOUs to bid their resources into the CPE's solicitation at competitive market prices, removing the levelized fixed cost requirement formerly adopted. CPE procurement costs will be forecasted and implemented in rates through the annual ERA forecast proceeding.

CalCCA's comments on Phase 2 proposals supported the CPUC conducting an loss of load expectation (LOLE) study to inform the planning reserve margin (PRM). CalCCA recommended including updated forced outage estimates as inputs into the LOLE. It also supported using LOLE analysis to update the PRM as opposed to ad hoc increases to the PRM that are not based on robust analysis and not officially incorporated into the RA program. Finally, CalCCA argued the PRM should be reviewed after a reasonable period of time or upon significant changes to the inputs.

The workshop report describes the workshop process and summarizes the proposals. PG&E's initial proposal and a new proposal by SCE were refined and converged into a proposal for monthly slices of 24 separate hours. Gridwell proposed monthly slices based on gross peak and net peak hours only. With respect to resource counting, the ELCC approach was generally associated with the Gridwell framework and the exceedance approach was associated with the PG&E/SCE framework for solar and wind resources.

- **Analysis:** The Proposed Decision would make a number of changes to the CPE, including changes to encourage LSEs to self-show resources and modifying the timeline of CPE activities. The results of the LOLE study could impact the thinking and formation of the slice-of-day reliability framework being developed in the RA Reform Track of this proceeding that seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours and would move RA from a monthly compliance obligation to a seasonal obligation.
- **Next Steps:** The procedural schedule for the ongoing tracks and working groups are as follows:

#### Phase 1

- Comments on PD: March 2, 2022
- Reply comments on PD: March 7, 2022
- Final Decision: no sooner than March 17, 2022

#### Phase 2

- Workshop on the LOLE study: March 3, 2022
- Comments on the LOLE study, workshop, and CEC Working Group Report: March 14, 2022
- Reply comments: March 22, 2022
- CAISO draft 2023 LCR Report: April 15, 2022
- Comments on draft 2023 LCR Report: April 22, 2022
- CAISO final 2023 LCR and FCR Report: April 29, 2022
- Comments on final 2023 LCR and FCR Report: May 6, 2022
- Reply comments on final 2023 LCR and FCR Report: May 13, 2022
- Proposed Decision: May 2022
- Final Decision: June 2022

#### Reform Track

- Comments on Workshop Report: TBD

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

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

## PG&E's 2019 ERRR Compliance

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

- **Background:** Phase 1 has been resolved. The September 7, 2021, Ruling consolidated the Phase 2 ERRR compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:
  - What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 PSPS events?
  - Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.

At the October 26, 2021, workshop hosted by Energy Division, the IOUs (PG&E, SCE, and SDG&E) made a joint presentation of their proposal for a methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events. The Joint IOUs' testimony provided additional information on the common methodology for calculating the potential unrealized sales that may result from a PSPS event to be used in a potential rate disallowance, which relies on the energy-related portion of the CPUC-jurisdictional distribution charge for this purpose. CCA representatives pushed back at the October 26, 2021, workshop that the IOUs had not considered unrealized revenues from utility-owned generation that had not been bid into the CAISO market. The ALJ requested the CCAs make a motion to clarify whether that issue is in scope in the proceeding.

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

- **Details:** The Joint IOUs' testimony responded to recommendations made by the CCA Parties and TURN in their respective testimonies and urged the CPUC to adopt the methodology the IOUs presented in their Opening Testimony to calculate any potential disallowance/penalty associated with future PSPS events. 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.

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

the need to account any such reductions if generation resources are forced offline due to PSPS events.

The CCA Parties recommended the following:

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.
- **Next Steps:** TBD.
- **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](#).

## Provider of Last Resort Rulemaking

On February 24, 2022, the ALJ issued a Ruling confirming that the second workshop in Phase 1 will take place on March 7, 2022, distributing an agenda for the workshop, and setting forth questions on which parties may comment during the workshop, as well as in written comments after the workshop.

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

The Scoping Memo and Ruling issued September 16, 2021, provides that Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an



existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.

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

- POLR service should be limited to 60 days to allow returned customers to transition from the returning LSE to the customer's chosen LSE, consistent with the existing "safe harbor" provision for DA switching.
  - Given the limited term and scope of service and the need to avoid unnecessary costs, the POLR should not engage in advance procurement or hedging.
  - RPS and IRP responsibility for returned customers should shift directly from the returning LSE to the customer's new LSE, with a waiver of these obligations for the POLR consistent with the existing waiver for RA obligations adopted in D.20-06-031.
  - The CPUC should compare Reentry Fees and actual costs for Western Community Energy's customer return to determine whether the current formulation provides sufficient precision to ensure a reasonable outcome.
  - A POLR right of first refusal of procurement contracts held by the returning LSE raises legal and commercial issues and should not be considered.
  - To minimize the risk of LSE default by newly launched CCA, Implementation Plan requirements should be modified to incorporate a milestone procedure to be administered by the CCA's governing board, quarterly updates to Energy Division on the status of milestone achievement, transparency through the use of a publicly available information portal available, and feasibility studies provided to the local governing board built on transparent and standardized referents.
  - Financial service requirements (FSR) should vary with the financial health of an LSE, limiting FSRs for LSEs maintaining investment-grade credit ratings and LSEs voluntarily providing limited metrics to the CPUC for review; all other LSEs should bear responsibility for the currently formulated FSR.
- **Details:** The February 24, 2022 Ruling confirmed that the second workshop in Phase 1 will take place on March 7, 2022. It also distributed an agenda for the workshop, and set forth questions on which parties may comment during the workshop, as well as in written comments after the 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 scheduled for March 7, 2022. Comments on the workshop and responses to questions presented are due March 28, 2022.
  - **Additional Information:** [Ruling](#) rescheduling second workshop date (February 24, 2022); [Ruling](#) setting second workshop and comment period (December 31, 2021); [Ruling](#) requesting comments (November 23, 2021); Golden State Power Cooperative [Motion](#) to remove cooperatives as respondents (October 28, 2021); [Scoping Memo and Ruling](#) (September 16,

2021); [Ruling](#) scheduling prehearing conference (April 30, 2021); [Order Instituting Rulemaking](#) (March 25, 2021); Docket No. [R.21-03-011](#).

## RA Rulemaking (2019-2020)

On February 11, 2022, the CPUC issued D.22-02-008, denying Western Power Trading Forum's (WPTF) Application for Rehearing of D.20-06-002, which adopted implementation details for the central procurement of multi-year local RA procurement.

- **Background:** This proceeding had three tracks, which have now concluded. Track 1 addressed 2019 local and flexible RA capacity obligations and several near-term refinements to the RA program. D.19-10-020 purported to affirm existing RA rules regarding imports, but adopted a distinction in the import RA compliance requirements for resource-specific and non-resource specific contracts and required, for the first time, that non-resource-specific resources self-schedule (i.e., bid as a price taker) in the CAISO energy market. D.20-06-028 adopted revisions to the Resource Adequacy import rules based on Energy Division's proposal, with modifications.

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

The second Track 2 Decision, D.20-06-002, adopted implementation details for the central procurement of multi-year local RA procurement to begin for the 2023 compliance year in the PG&E and SCE (but not SDG&E) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The Decision rejected a settlement agreement between CalCCA and seven other parties that would have created a residual central buyer structure and a multi-year 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.

**Details:** D.22-02-008 denied WPTF's July 17, 2020, Application for Rehearing of D.20-06-002, the Track 2 Decision creating a multi-year central procurement regime for local RA capacity. WPTF had requested rehearing and reconsideration of the rejected settlement agreement between WPTF, CalCCA, and other parties, arguing that D.20-06-002 will discourage the procurement of local resources by individual LSEs, discriminates against natural gas resources while increasing the need for CAISO backstop procurement, may undermine reliability by making it more difficult to integrate renewables with the larger western grid, and creates a "sale for resale" procurement construct that could place it under FERC's jurisdiction as a wholesale, rather

than a retail, transaction. D.22-02-008 found that good cause for rehearing had not been demonstrated.

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

- **Analysis:** D.22-02-008 upheld the CPUC’s decision, D.20-06-002, which established a CPE. Moving to a CPE beginning for the 2023 RA compliance year impacted VCE’s local RA procurement and compliance, including affecting VCE’s three-year local RA requirements as part of the transition to the central procurement framework. Eventually, it will eliminate the need for monthly local RA showings and associated penalties and/or waiver requests from individual LSEs, but it also eliminates VCE’s autonomy with regard to local RA procurement and places it in the hands of PG&E.
- **Next Steps:** The only item remaining to be addressed in this proceeding is WPTF’s remaining outstanding Application for Rehearing. Remaining RA issues will be addressed in the successor RA rulemakings.
- **Additional Information:** [D.22-02-008](#) denying WPTF’s Application for Rehearing (February 11, 2022); [D.20-09-003](#) denying PFM’s filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF’s [Application for Rehearing](#) of D.20-06-028 (August 5, 2020); WPTF’s [Application for Rehearing](#) of D.20-06-002 (July 17, 2020); [D.20-06-028](#) on Track 1 RA Imports (approved June 25, 2020); [D.20-06-002](#) establishing a central procurement mechanisms for local RA (June 17, 2020); [D.20-03-016](#) granting limited rehearing of D.19-10-021 (March 12, 2020); [D.20-01-004](#) on qualifying capacity value of hybrid resources (January 17, 2020); [D.19-12-064](#) granting motion for stay of D.19-10-021 (December 23, 2019); [D.19-10-021](#) affirming RA import rules (October 17, 2019); [D.19-06-026](#) adopting local and flexible capacity requirements (July 5, 2019); Docket No. [R.17-09-020](#).

## Utility Safety Culture Assessments

On February 17, 2022, the CPUC’s Safety Policy Division notified stakeholders of plans to hold an informational workshop on March 11, 2022.

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

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

- **Details:** The March 11, 2022, workshop will include brief presentations followed by a question and answer session from a panel of regulatory and academic safety culture experts. An agenda with more information on the workshop is forthcoming.
- **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 workshop is scheduled for March 11, 2022.
- **Additional Information:** [Order Instituting Rulemaking](#) (October 7, 2021); Docket No. [R.21-10-001](#).

## PCIA Rulemaking

No updates this month. 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 modified the PCIA market price benchmark release date to October 1 and the deadline for ERRA forecast applications to May 15 to enable the Commission to timely issue decisions on ERRA forecast applications. It adopted party proposals to establish a policy for disposition of the year-end balance in the ERRA account and to modify the calculation of the ERRA trigger point and threshold. It also adopted party proposals to support efficient party access to ERRA forecast proceeding data.

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

- Whether greenhouse gas-free resources are under-valued in the PCIA, and if so, whether to adopt an adder or allocation mechanism.
- Whether to adopt a new method to include long-term fixed-price transactions in calculating the Renewables Portfolio Standard adder.
- Whether to modify the calculation of the PCIA energy index market price benchmark.
- Whether to provide CCAs with access to confidential, market sensitive ERRA monthly reports information for the non-proceeding purpose of creating PCIA rate forecasts.
- **Analysis:** D.22-01-023 made 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, 2021); [D.21-05-030](#) on PCIA Cap and Portfolio Optimization (May 24, 2021); [D.21-03-051](#) granting petition to modify D.17-08-026 (March 26, 2021); [Amended Scoping Memo and Ruling](#) (December 16, 2020); [Joint IOUs PFM of D.18-10-019](#) (August 7, 2020); [D.20-08-004](#) on Working Group 2 PCIA Prepayment (August 6, 2020); [D.20-06-032](#) denying PFM of D.18-07-009 (July 3, 2020); [D.20-03-019](#) on departing load forecast and presentation of the PCIA (April 6, 2020); [D.20-01-030](#) denying rehearing of D.18-10-019 as modified (January 21, 2020); [D.19-10-001](#) (October 17, 2019); [D.18-10-019](#) Track 2 Decisions adopting the Alternate Proposed Decision (October 19, 2018); [D.18-09-013](#) Track 1 Decision approving PG&E Settlement Agreement (September 20, 2018); Docket No. [R.17-06-026](#).

## 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](#).

## 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 ERRR compliance proceeding. The tentative list of issues include whether sales forecasting methods for adjusting revenue requirement under current decoupling policy should be adjusted to account for power not sold or purchased during a Public Safety Power Shutoff (PSPS) event in 2020, whether it is appropriate for PG&E to return the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2020, and the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2020 PSPS events.

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

Finally, PG&E agreed to transfer from PABA to ERRR 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. [1.15-08-019](#).

## 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](#).

## Glossary of Acronyms

<b>AB</b>	Assembly Bill
<b>AET</b>	Annual Electric True-up
<b>ALJ</b>	Administrative Law Judge
<b>BioMAT</b>	Bioenergy Market Adjusting Tariff
<b>BTM</b>	Behind the Meter
<b>CAISO</b>	California Independent System Operator
<b>CAM</b>	Cost Allocation Mechanism
<b>CARB</b>	California Air Resources Board
<b>CEC</b>	California Energy Commission
<b>CPE</b>	Central Procurement Entity
<b>CPUC</b>	California Public Utilities Commission
<b>CPCN</b>	Certificate of Public Convenience and Necessity
<b>CTC</b>	Competition Transition Charge
<b>DA</b>	Direct Access
<b>DWR</b>	California Department of Water Resources
<b>ELCC</b>	Effective Load Carrying Capacity
<b>ERRA</b>	Energy Resource and Recovery Account

<b>EUS</b>	Essential Usage Study
<b>GRC</b>	General Rate Case
<b>IEPR</b>	Integrated Energy Policy Report
<b>IFOM</b>	In Front of the Meter
<b>IRP</b>	Integrated Resource Plan
<b>IOU</b>	Investor-Owned Utility
<b>ITC</b>	Investment Tax Credit
<b>LSE</b>	Load-Serving Entity
<b>MCC</b>	Maximum Cumulative Capacity
<b>OII</b>	Order Instituting Investigation
<b>OIR</b>	Order Instituting Rulemaking
<b>PABA</b>	Portfolio Allocation Balancing Account
<b>PD</b>	Proposed Decision
<b>PG&amp;E</b>	Pacific Gas & Electric
<b>PFM</b>	Petition for Modification
<b>PCIA</b>	Power Charge Indifference Adjustment
<b>POLR</b>	Provider of Last Resort
<b>PSPS</b>	Public Safety Power Shutoff
<b>PUBA</b>	PCIA Undercollection Balancing Account
<b>PURPA</b>	Public Utility Regulatory Policies Act of 1978 (federal)
<b>QC</b>	Qualifying Capacity
<b>QF</b>	Qualifying Facility under PURPA
<b>RA</b>	Resource Adequacy
<b>RDW</b>	Rate Design Window
<b>ReMAT</b>	Renewable Market Adjusting Tariff
<b>RPS</b>	Renewables Portfolio Standard
<b>SCE</b>	Southern California Edison
<b>SED</b>	Safety and Enforcement Division (CPUC)
<b>SDG&amp;E</b>	San Diego Gas & Electric
<b>TCJA</b>	Tax Cuts and Jobs Act of 2017
<b>TOU</b>	Time of Use
<b>TURN</b>	The Utility Reform Network
<b>UOG</b>	Utility-Owned Generation
<b>WMP</b>	Wildfire Mitigation Plan
<b>WSD</b>	Wildfire Safety Division (CPUC)