REGULATORY UPDATE FOR NOVEMBER 22, 2021 (WEEK OF NOVEMBER 15)

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC or COMMISSION)

New Proposed Decisions and Draft Resolutions[1]

None.

Voting Meetings

The Commission's next voting meeting is December 2, 2021. The initial agenda for this meeting is scheduled to be published November 22, 2021.

The Commission held a voting meeting on November 18, 2021. The agenda included the following energy-related items.

Item 3. Draft Resolution L-612. On November 19, 2020, Brandon Rittiman sought the disclosure of certain records of the CPUC pursuant to the California Public Records Act. Rittiman sought all communications between Commission President Marybel Batjer or her executive staff with the following employees of the Governor's office: Ana Matasanos, Alice Reynolds, Ann Patterson, and Rachel Wagoner. This Resolution would deny the appeal of Rittiman for a reconsideration of the Commission Staff determination that the records he sought are exempt from disclosure pursuant to California Government Code § 6254(l), which exempts from public disclosure "[c]orrespondence of and to the Governor or employees of the Governor's office or in the custody of or maintained by the Governor's Legal Affairs Secretary." **Approved.**

Item 6. Draft Resolution 5175-E. On October 23, 2020, Southern California Edison Company (SCE) filed AL 4322-E, requesting approval of the process to qualify Electric Vehicle Supply Equipment (EVSE) for the Charge Ready 2 Infrastructure and Market Education program (Charge Ready 2). SCE proposes two processes: one to continually approve EVSE that meet technical qualifications on a rolling basis for customers within Charge Ready 2 who will own the EVSE, and one in which SCE will issue a Request for Qualification for purchasing EVSE that SCE will own through the program. As proposed, the EVSE that are either purchased or qualified through these pathways must conform to the applicable eligibility requirements within SCE's Standard Equipment EVSE Qualification Package. This Resolution authorizes, with modifications, SCE's qualification processes. **Approved.**

Item 13. A.19-11-009 (PG&E rate design). This decision adopts marginal costs for Pacific Gas and Electric (PG&E) to be used in the allocation of revenue among PG&E's

[1] Per CPUC Rules of Practice and Procedure Rule 14.3, comments on proposed decisions are due 20 days after issuance of the proposed decision, and reply comments are due five days thereafter. Comments on draft resolutions are due 20 days after the draft resolution appears in the CPUC's daily calendar, per Rule 14.5.

customer classes and the design of retail rates for PG&E's customers. This decision largely adopts PG&E's proposed marginal costs and methodologies for deriving them but adopts marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association. This decision also adopts, without modification, several uncontested settlements on rate design issues and revenue allocation. The proceeding will remain open to consider issues related to real-time pricing proposals for PG&E's customers. **Signed, D.21-11-016**

Item 19. R.20-01-007 (Gas system reliability). D.19-05-030 adopted an eight-stage winter penalty structure for Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) that allows for more moderate increases between Operational Flow Order (OFO) stages than the prior winter penalty regime. Instead of the OFO penalty increasing from $5 to $25 between Stages 3 and 4, the new rules create intermediate Stages 3.1, 3.2, and 3.3, which impose penalties of $10, $15, and $20, respectively. The revised rules have been in effect for the past two winters, but they were due to expire on October 31, 2021. On October 12, 2021, the Assigned Commissioner issued a ruling temporarily extending the OFO rules and structure adopted in D.19-05-030 until a full Commission decision is issued concerning the matter. This decision affirms the Assigned Commissioner's ruling and approves the extension of the current winter OFO rules for the six months beginning November 1, 2021. **Signed, D.21-11-021.**

Item 27. R.19-10-005 (EPIC program). This decision authorizes PG&E, SCE, and SDG&E (collectively the IOUs) to continue in their role as administrators of the Electric Program Investment Charge (EPIC) program, subject to additional administrative requirements. Like the California Energy Commission (CEC), the IOUs are authorized to file two five-year investment plans, with the first cycle covering 2021-2025 (EPIC 4) and the second cycle covering 2026-2030 (EPIC 5). The decision authorizes EPIC 4 investment plan budgets of $18.444 million annually for PG&E, $3.24 million annually for SDG&E, and $15.131 million annually for SCE. **Withdrawn.**

Item 27A. The alternate proposed decision (APD) of Commissioner Guzman Aceves differs from the Proposed Decision (PD, Item 27) in that it provides further justification for the continuation of the IOU administrative role, while only authorizing their funding through 2025. Additionally, the APD differs from the PD in that it increases the administrative cost cap for a fourth EPIC administrator, the CEC, from a soft cap of 10% to a firm cap of 15%. The APD matches the outcome of the PD in other respects. **Signed, D.21-11-028.**

Item 28. R.18-07-003 (RPS Implementation). This decision changes the confidentiality provisions relating to renewable portfolio standard (RPS) procurement records, generally allowing broader, and earlier, access to RPS procurement records. **Signed, D.21-11-029.**

Item 28A. This APD from Commissioner Rechtschaffen adopts a revised confidentiality matrix for RPS-eligible procurement records that allows the following: (a) RPS load forecast data will be confidential for two future years and the year of filing; (b) RPS-eligible contract prices and terms will become public six months after the date of Commission approval; (c) for contracts that do not require Commission approval, the contract prices and terms will become public six months after contract execution date; (d) aggregated bid information from an Investor-Owned Utility's competitive solicitation will be public after the final contract is submitted for Commission approval when there are at least three bidders in the resource category; (e) individual bid information will become public one year after the final contract is submitted to the Commission for approval; and (f) contract amendments cannot revise prior confidentiality terms, and the public can access the contract data 30 days after the new contract execution date. **Withdrawn.**

CALIFORNIA ISO (CAISO)

Energy Imbalance Market (EIM) Governing Body Executive Session

The EIM Governing Body has scheduled an executive session for November 22, 2021. The final agenda may be found here.

Western Area Power Administration (WAPA) EIM Implementation Agreement

The Federal Energy Regulatory Commission approved the California ISO's EIM Implementation Agreement with WAPA on November 17, 2021. The Agreement sets out the terms by which the California ISO will extend the EIM to include WAPA.

Stakeholder Initiatives: Upcoming Meetings and Deadlines

Annual Policy Initiatives Roadmap Process. The California ISO held a call on November 16, 2021 to discuss the 2022 draft Policy Initiatives Roadmap, as part of the Annual Policy Initiatives Roadmap Process. The 2022 Revised Policy Initiatives Catalog may be found here. Comments are due December 1, 2021.

Resource Adequacy Enhancements Phase 2 Initiative. The California ISO is postponing stakeholder engagement activities for the Resource Adequacy Enhancements Phase 2 initiative until February 2022 to align the timeline with other contingent policy initiatives.

2021-2022 Transmission Planning Process. The California ISO held a public stakeholder call on November 18, 2021 to discuss the 2021-2022 transmission planning process. Comments on the stakeholder call are due December 2, 2021.

Adjustment to Intertie Constraint Penalty Prices. The California ISO held a stakeholder call on November 19, 2021 to discuss proposed adjustments to intertie constraint penalty prices with stakeholders. Comments are due December 3, 2021.

EIM Resource Sufficiency Evaluation Enhancements. The California ISO has scheduled a stakeholder call on December 14, 2021 to discuss the revised draft final proposal for Phase 1 of the EIM Resource Sufficiency Evaluation Enhancements initiative. Comments on the revised proposal and meeting are due December 22, 2021.

New Initiative: Central Procurement Entity Implementation. The California ISO will hold a stakeholder call on November 22, 2021 to discuss the Issue Paper/Straw Proposal for the Central Procurement Entity Implementation initiative. Comments are due December 6, 2021.

Maximum Import Capability Enhancements. The California ISO will hold a public stakeholder call on November 23, 2021 to discuss the draft final tariff language and draft Business Practice Manual language for the Maximum Import Capability Enhancements initiative. Written comments on the draft final proposal and draft tariff language are due December 7, 2021.

CALIFORNIA ENERGY COMMISSION (CEC)

EPIC

The CEC has announced a two-day EPIC Symposium scheduled for December 14-15, 2021. The Symposium will focus on how California's investments in public interest research will transform the state's energy system. Over the two-day event, panel sessions will focus on:

- Grid resiliency and reliability
- Equity and affordability
- Decarbonization of the built environment
- Innovation and entrepreneurship in California

To register for this event, visit https://www.energizeinnovation.fund/events/epic-symposium#tab-registration.

2021 Integrated Energy Policy Report (IEPR)

The CEC has announced a few upcoming 2021 IEPR workshops to be held in early December 2021.

On December 2, 2021, the CEC will hold a two-session workshop focused on the Electricity and Demand Forecast for 2021-2025:

- Session 1, 10 a.m. PT: Self-Generation and Additional Achievable Energy Efficiency and Fuel Substitution Forecast Results
- Session 2, 2 p.m. PT: Transportation, End-User Gas Forecast Results, and Overall Electricity Sales Results

On December 3, 2021, the CEC will hold a workshop to receive an update on the progress made by the CEC's stakeholder working group process on supply-side demand response. The workshop will be held remotely across two sessions:

- Session 1, 10 a.m. PT: Supply-Side Demand Response – Reliability and Resource Planning, Market Opportunity, and Issues
- Session 2, 2 p.m. PT: Supply-Side Demand Response – Stakeholder Working Group Process and Path Forward

CEC Business Meetings

The next CEC Business Meeting is scheduled for December 8, 2021.

CALIFORNIA AIR RESOURCES BOARD (ARB)

On December 1, 2021, ARB will host a virtual public meeting of the Assembly Bill (AB) 32 Environmental Justice Advisory Committee. The agenda and a link to the meeting are available here.

ARB's next regular Board meeting will be held December 9-10, 2021. The agenda will be available here 10 days prior to the meeting.

ARB is holding virtual public workshops as part of the AB 32 Scoping Plan Update. On December 2, 2021, ARB will hold a technical workshop on modeling land management scenarios associated with greenhouse gas emissions and sinks from state natural and working lands, in order to develop a target for natural and working lands to contribute to achieving carbon neutrality by 2045. Recordings of past AB 32 Scoping Plan Update meetings and workshops are available here.

ARB is accepting informal public comments on the proposed Advanced Clean Fleets regulation, which aims to achieve a zero-emissions truck and bus California fleet by 2045. Comments may be submitted here on or before December 31, 2021.

IDAHO

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations

On May 27, 2021, PacifiCorp dba Rocky Mountain Power filed an application to increase its energy rates in Idaho. A number of industrial customers and organizations intervened in the matter. On October 25, 2021, the parties to the case submitted to the Idaho Public Utilities Commission a settlement stipulation to resolve the matter. Under the stipulation, the parties agreed to an $8 million (2.9%) rate increase for Idaho customers, deferral of incremental depreciation expense of $13,940,303 (to be amortized over four years), amortization (over three years) of Deer Creek Mine regulatory assets – including amortization of $14,347,296 in unpaid royalties and $6,521,059 in unpaid future remediation expenses, continued deferral of certain repowered and new wind facility costs, amortization of certain federal tax amounts, and a new valuation of Bayer Corporation's curtailment products effective as of January 1, 2022. The commission held a hearing to take evidence on the stipulation on November 15, 2021 and is expected to approve the stipulation.

MINNESOTA

MPUC Meeting This Week

On November 23, 2021 at 11 a.m. PT, the Minnesota Public Utilities Commission (Commission) will hold a public agenda meeting to set 2022 forecasted energy rates for Northern States Power Company d/b/a Xcel Energy, Minnesota Power, and Otter Tail Power Company. The Commission will also hear a deferred accounting request made by Minnesota Power and review Otter Tail Power Company's and Xcel Energy's service quality reports.

OREGON

Portland Gas and Electric (PGE) Granted Extension to File Next Integrated Resource Plan (IRP)

Last Thursday, November 18 the Oregon Public Utility Commission (OPUC) issued Order 21-422, which granted an extension to PGE for filings its next IRP. Per OAR 860-027-0400(3), a utility must file an IRP within two years of its previous IRP acknowledgment. However, an extension may be granted if the utility does not intend to undertake a significant resource action between filings. PGE's last IRP was acknowledged by the OPUC on March 16, 2020. Under the recent order, PGE may now file its IRP on or before March 31, 2023 with the condition that the utility perform an analysis of qualifying facility forecasts and solar generation profiles in accordance with Order No. 21-215 and file its findings by March 16, 2022. The recent order can be located here.

TEXAS

On October 21, 2021, the Public Utility Commission of Texas (PUCT) approved a rule that creates requirements for power companies to better prepare for winter weather. The rule stems from the Texas Legislature's passage of Senate Bill 3 (S.B. 3) in response to the devastation caused to the energy grid by winter storm Uri.

S.B. 3, effective June 8, 2021, is a multi-pronged law that attempts to make the Texas energy system more resilient to the effects of extreme winter weather events. Key to S.B. 3 is a requirement that the PUCT implement winter weatherization requirements so that each of the entities providing electric generation service must implement measures to prepare its generation assets to provide adequate electric generation service during a weather emergency. The new rule, codified as 16 Texas Administrative Code § 25.55, requires electric generators and transmission service providers (TSPs) (collectively, generation entities) to implement the winter weather readiness recommendations identified in the 2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices and the FERC/NERC 2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011. The rule also requires affected entities to fix any known, acute issues that arose from winter weather conditions during the 2020-2021 winter weather season. The deadline for implementation of many components of the new rule is December 1, 2021.

By December 1, 2021, a generation entity within the Electric Reliability Council of Texas (ERCOT) must:

1. Use best efforts to implement weather emergency preparation measures intended to ensure sustained operation of all cold weather critical components during winter weather conditions;
2. Install adequate wind breaks for resources susceptible to outages or derates caused by wind; inspect thermal insulation for damage or degradation and repair damaged or degraded insulation; confirm the operability of instrument air moisture prevention systems; and conduct maintenance of freeze protection components for all applicable equipment, including fuel delivery systems controlled by the generation entity, the failure of which could cause an outage or derate;
3. Establish a schedule for testing of such freeze protection components on a monthly basis from November through March, and install monitoring systems for cold weather critical components, including circuitry providing freeze protection or preventing instrument air moisture;
4. Use best efforts to address cold weather critical component failures that occurred due to winter weather conditions during the 2020-2021 winter;
5. Provide training on winter weather preparations and operations to relevant operational personnel; and
6. Determine minimum design and experienced operating temperature and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction.

The generation entity must also, by December 1, 2021, submit to both the PUCT and ERCOT, on a form prescribed by ERCOT, a winter weather readiness report that:

1. Provides a description of all activities engaged in by the generation entity to complete the above-listed requirements, including any good-cause-based reason for noncompliance; and
2. Includes a notarized attestation sworn by the generation entity's highest-ranking representative, official, or officer attesting to the accuracy of the information in the report and completion of all of the above-listed requirements, subject to any notice of or request for good-cause exception.

The draft report forms for both generators and TSPs is available here: [Winter Weather Readiness (ercot.com)](ercot.com).

With the extremely tight timeframe to comply with the rule, generation entities are entitled to request an exception to the requirements for good cause. The generation entity must still file a winter weather readiness report; however, that report would include a notice that provides:

1. An explanation and supporting documentation of the generation entity's inability to comply with a specific requirement;
2. A description and supporting documentation of the generation entity's efforts to comply with the requirements; and
3. A plan, including supporting documentation and a proposed deadline for each unfulfilled requirement, to comply with requirements.

PUCT Staff will collaborate with ERCOT in reviewing these good-cause exemption notices, and the PUCT reserves the right to notify the generation entity that it disagrees with the assertion of good cause. If PUCT Staff disagrees with the assertion of good cause, the generation entity must preserve the good-cause exemption by submitting, within seven days of receipt of the notice of disagreement, a request for approval of the good-cause exemption to the PUCT. The request for approval must contain, in addition to all of the requirements of the good-cause exemption notice, (1) proof that notice of the request has been provided to ERCOT, and (2) a notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the entity attesting to the accuracy and veracity of the information in the request for approval.

Another component of the new rule provides for ERCOT inspections of generators and TSPs to ensure compliance with the requirements in the 2021-2022 winter season. ERCOT has the ability to make determinations on good-cause exemption requests during an inspection. ERCOT will prioritize inspections based on the risk level. The outcome of the ERCOT inspection may subject a generator to a PUCT enforcement investigation or civil penalties.

This rule represents the first of two phases in the PUCT's response to the requirements of S.B. 3. At a future date, the PUCT will implement a second, more comprehensive set of weather emergency preparedness reliability standards.

UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Electric Vehicle Infrastructure Program

On July 29, 2020, PacifiCorp dba Rocky Mountain Power filed an application for approval of an electric vehicle infrastructure program authorized by Electric Vehicle Charging Infrastructure Amendments. Through the application, Rocky Mountain Power sought approval of a plan to install certain electric vehicle charging infrastructure, the implementation of a tariff (Schedule 198) through which the company would collect \$5 million per year for 10 years to fund the plan, the approval of a balancing account, approval of a new charging station tariff (Schedule 60) that would list prices for and details concerning electric vehicle charging stations that would be owned by the company, and approval of a new tariff (Schedule 120) through which a customer incentive pilot program would be extended. On November 17, 2021, a number of parties (but not all parties) entered into a settlement stipulation that was provided to the Utah Public Service Commission. The stipulation contains the following proposed elements of an electric vehicle charging plan:

- A commitment by the company to invest in utility-owned charging stations;
- Funding to be provided by the company for make-ready infrastructure systems;
- A commitment by the company to participate in certain studies and projects that will be led by state and federal agencies and academic institutions to monitor electric infrastructure advances;
- A continuation of current incentives offered through Schedule 120 for eligible customers, and a requirement that residential customers will install smart/networked chargers;
- The ability of the company to collect $5 million per year for 10 years through Schedule 198;
- Approved rates for Schedule 60; and
- Approval of a time of use pilot program for the plan.

A hearing on the matter is scheduled for November 22, 2021, and a decision from the Utah commission is expected within 60 days following the hearing.

WASHINGTON

Avista's Draft 2022 All-Source Request for Proposals (RFP)

On November 1, 2021, Avista filed a draft 2022 RFP with the Washington Utilities and Transportation Commission. The 2022 RFP is now available for public comment by any interested person. The 2022 RFP is posted here. The last day to file comments is December 15, 2021.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

FERC's monthly open meeting occurred November 18, 2021. Notable decisions were as follows:

- FERC initiated a rulemaking (discussed below) to consider whether reactive power resources should be compensated differently than provided by current market design, and also whether resources connected to a distribution system should be eligible for reactive power capability compensation through transmission rates. Docket No. RM22-2-000.

- FERC denied rehearing of a complaint filed by Hecate Green Energy County 3 LLC against the NYISO for alleged violations of the market operator's generator interconnection process. Docket No. EL21-49-001.
- FERC denied a complaint filed by Luna Valley Solar (Luna) against PG&E and CAISO regarding a large generator interconnection agreement for a solar + battery storage facility under development in California. Luna had sought relief from a financial security posting deadline that it alleged became irrelevant due to delays in the associated network upgrades. However, FERC determined that the posting requirement did not violate the CAISO tariff. Docket No. EL21-70-000.
- Lastly, FERC dismissed a complaint, for lack of ripeness, filed by Edgecombe Solar against several Duke Energy (Duke) companies, alleging that Duke's Affected System Operator Agreement violated its OATT for failure to provide reimbursements for network upgrades that Duke built in its role as an affected system operator. Docket No. EL21-73-000.

The Senate unanimously confirmed D.C. Public Service Commission Chairman Willie Phillips (Democrat) as the newest member of FERC. Phillips will join Glick (Chairman – Democrat), Clements (Democrat), Danly (Republican), and Christie (Republican) to bring the Commission back to a full five-member complement.

On November 4, 2021, voters in Maine passed a ballot initiative (Maine Question 1) to stop construction of the New England Clean Energy Connect (NECEC) project that would deliver 1,200 MW of clean hydropower from Quebec, Canada to the ISO-NE grid. The referendum effort to stop the NECEC was championed by conservation groups and a number of gas-fired power plant owners. The impact of this development on the FERC's ongoing complaint proceedings remains to be seen.

Market-Based Rate (MBR) Database: FERC extended the deadline for baseline submissions to the new MBR relational database. Baseline submissions will now be due February 1, 2022. Baseline submissions are required for all entities with MBR authorization.

Reactive Power Capability Compensation: FERC on November 18, 2021 issued a Notice of Inquiry (NOI) seeking comments on reactive power capability compensation and market design. Reactive Power Capability Compensation. Reactive power is a critical component of the bulk electric system. Almost all bulk electric power is generated, transported, and consumed in alternating current (AC) networks. These AC systems consume both real and reactive power. Reactive power supports the voltages necessary for system reliability to allow the supply of real power from generation to load. Reactive power is considered an ancillary transmission service, and costs are recovered separately from the cost of standard transmission service.

In 1999, the FERC approved a method proposed by American Electric Power (AEP) Service Corporation for allocating costs for a synchronous generator between real and reactive power capability. *Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999). This so-called AEP methodology is now recommended by FERC when an entity seeks to recover reactive power capability costs.

Over the last decade, reactive power compensation has become a key component in cost recovery for renewable resources, and the AEP methodology has been applied to non-synchronous generators such as solar and wind facilities. The NOI recognizes this shift in the industry. FERC noted that it has processed approximately 260 reactive power proceedings in PJM and 125 reactive power proceedings in MISO, the two RTO/ISOs where reactive power compensation is greatest. The majority of these proceedings involve renewable resource generators.

In the NOI, FERC is seeking comments on the applicability of the AEP methodology to renewable resources. The AEP methodology was initially developed for synchronous generators, and FERC seeks to examine the appropriateness of its application to non-synchronous generators. Specifically, FERC seeks comments on:

1. The failure of the AEP methodology to account for the degradation of a resources' reactive power capability over time;
2. The applicability of the cost-of-service ratemaking principles in the AEP methodology to the categories of equipment unique to non-synchronous generators;
3. The lack of specific accounts in the Uniform System of Accounts for non-hydro non-synchronous resources;
4. The lack of verifiable data underlying the cost-of-service rates. A majority of the reactive power applicants have been granted waivers from FERC's accounting and reporting requirements, so these applicants do not have accounting entries as found in the FERC Form No. 1 to support the reactive power rates; and
5. Whether the PJM compensation model for reactive power should be revised due to possible overcompensation. The PJM market monitor has argued that reactive power compensation should not be provided via a separate cost-of-service compensation model, and instead should be determined based on capacity markets in PJM. Alternatively, the PJM market monitor argues that the current scheme should be revised to avoid overcompensating resources for reactive power capability.

FERC also seeks comment on (i) alternatives to the AEP methodology, particularly with respect to different resource types; (ii) the various compensation models across the RTO/ISOs; and (iii) whether resources connected to a distribution system should be eligible for reactive power capability compensation through transmission rates.

Initial comments are due 60 days after the date of publication in the Federal Register and reply comments are due within 30 days thereafter.