REGULATORY UPDATE FOR APRIL 5 (WEEK OF MARCH 29)

CALIFORNIA PUBLIC UTILITIES COMMISSION

New Proposed Decisions and Draft Resolutions[1]

Draft Resolution ALJ-402. This draft resolution denies San José Clean Energy's (SJCE) appeal of Citation No. E-4195-0074 by the California Public Utilities Commission's (Commission or CPUC) Consumer Protection and Enforcement Division. Citation No. E-4195-0074 cites and fines SJCE for failing to procure certain of its 2020 year-ahead system resource adequacy obligations. The resolution finds, among other conclusions, that SJCE rejected bids that would have met its system RA obligations, and did so deliberately on the basis of market conditions, notwithstanding the Commission's express rejection of a waiver process based solely on market conditions. SJCE must pay the penalty of $1,116,149.48, 45 days from the date of issuance of the resolution.

Draft Resolution E-5142. This resolution approves five contracts for incremental system reliability resources that Southern California Edison Company procured through the Standard Track of its System Reliability Request for Offers solicitation in 2020. Southern California Edison Company undertook this procurement to meet its 2022 and 2023 incremental procurement requirements pursuant to Decision 19-11-016 in the Integrated Resource Plan Rulemaking, 16-02-007. This resolution approves the contracts without modification. The approved contracts are:

Seller/Project	Technology Type	Capacity (MW)	Location and DAC Designation[2]	Contract Type	Initial Delivery Date	Contract Term
Sonoran West Solar Holdings, LLC/ Crimson	IFOM Lithium-Ion Battery	200	Blythe, CA (not in DAC)	RA with Put Options	8/1/2022	14 years 10 months
Silver Peak Solar, LLC/Eldorado Valley	IFOM Lithium-Ion Battery	60	Boulder City, NV (DAC adjacent)	Toll	8/1/2022	10 years

[1] Per California Public Regulatory Commission (CPUC or Commission) 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 Commission's daily calendar, per Rule 14.5.

Desert Peak Energy Storage I, LLC/Desert Peak	IFOM Lithium-Ion Battery	325	Palm Springs, CA (not in DAC)	Toll	8/1/2023	14 years 10 months
Sunrun Inc.	BTM Energy Storage-Demand Response	4.5	SCE Territory (not in DAC)	Demand Response	8/1/2023	10 years
Sunrun Inc. DAC Contract	BTM Energy Storage-Demand Response	0.5	SCE Territory (in DACs)	Demand Response	8/1/2023	10 years

Voting Meetings

The CPUC's next voting meeting will be held April 15, 2021. The agenda is scheduled to be published April 5, 2021.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

Generator Interconnection Application Window 4/1/21 – 4/15/21. The Cluster 14 Generation Interconnection Request window for new applications will be open April 1 through April 15, 2021.

Western EIM Governance Review Committee Executive Session Meeting. The California ISO has posted the final agenda for the April 7, 2021 Western Energy Imbalance Market (EIM) Governance Review Committee executive session teleconference meeting. Agenda may be found here: FinalAgenda-EIMGovernanceReviewCommitteeMeeting-Apr7-2021.pdf (westerneim.com).

LADWP and Public Service Company of New Mexico Join the EIM. The largest publicly owned utility in California and the largest electric power provider in New Mexico began participating in the California ISO's Western EIM on April 1.

Stakeholder Initiatives: Upcoming Meetings and Deadlines

Western EIM Sub-Entity Scheduling Coordinator Role. Comments on the draft final proposal are due April 9, 2021.

Flexible Ramping Product Refinements. The California ISO has posted revised draft tariff language for the Flexible Ramping Product Refinements initiative and is planning to file the language with the Federal Energy Regulatory Commission in April 2021.

BPM Change Management: Proposed Revision Requests and Updated BPMs Posted. On March 30, 2021, the California ISO posted new Proposed Revision Requests to Business Practice Manuals (BPMs), the California ISO recommendations, and final decisions on previously submitted PRRs. The ISO posted updated versions of BPMs on its BPM change management website. This triggers the beginning of the stakeholder review process.

Final 2022 and 2026 Local Capacity Technical Study Results. The California ISO has scheduled a stakeholder call on April 7, 2021, to present and discuss the final 2022 and 2026 local capacity technical study results that have been incorporated into the respective draft local capacity technical reports. Written comments on the final study results are due April 21.

CALIFORNIA ENERGY COMMISSION

At its April 14, 2021 Business Meeting, the California Energy Commission (CEC) will consider approval of Volume II of the 2020 Integrated Energy Policy Report (IEPR) Update, entitled *The Role of Microgrids in California's Clean and Resilient Energy Future, Lessons Learned from the California Energy Commission's Research*. On March 17, 2021, the CEC adopted two Volumes of the 2020 IEPR Update, Volume I: *Blue Skies, Clean Transportation* and Volume III: *California Energy Demand Forecast Update*. The CEC has begun work on the 2021 IEPR, adopting the Scoping Order for the proceeding on March 16, 2021.

CALIFORNIA AIR RESOURCES BOARD

On April 8, 2021, the California Air Resources Board (ARB) will hold a joint meeting with the California Transportation Commission and California Department of Housing and Community Development. The meeting will focus on planning for the state's transition to zero-emission vehicles by 2035 and the draft Climate Action Plan for Transportation Infrastructure. Pursuant to Assembly Bill 185 (Grayson 2019) and Assembly Bill 179 (Cervantes 2017), the agencies hold two joint meetings each year.

ARB has issued proposed modified text for public comment, revising its amendments to both the Regulation for the Reporting of Criteria Air Pollutants and Toxic Air Contaminants (Criteria and Toxics Reporting Regulation) and the Air Toxics "Hot Spots" Program Emission Inventory Criteria and Guidelines Report. The deadline for public comment is April 14, 2021. ARB states that the proposed amendments to the Criteria and Toxics Reporting Regulation are necessary to support efforts to reduce adverse and inequitable health impacts from air pollution to communities of concern. The amendments provide updated toxics data for air districts, so they may evaluate risks to residents related to the emissions of toxic contaminants pursuant to implementation of AB 2588. CARB will use the data to evaluate and update air toxic control measures. Under the Hot Spots Program, stationary sources are required to report the types and quantities of certain toxic substances their facilities routinely emit. ARB has proposed modifications to the amendments to the Criteria and Guidelines to provide ARB and air districts with a better understanding of stationary source toxic emissions, enhance public access to information on toxic pollutant emissions, and ensure that many new and emerging chemicals of concern are reported. ARB approved for adoption the proposed amendments to the Criteria and Toxics Reporting Regulation and the Hot Spots Program on November 19, 2020, subject to the additional conforming modifications now being made available for public comment.

MINNESOTA

1. Xcel Energy 2021 Stay Out, PUC Docket No. 20-743

On Friday, April 2, 2021, the Minnesota Public Utilities Commission (Commission) issued its written order in PUC Docket No. 20-743, approving Xcel's request to withdraw its pending rate case and collect its revenue deficiencies through the use of multiple true-up mechanisms (the 2021 Stay Out). The order can be found here. Xcel also received approval of a similar proposal for 2020 based on the apparent cost benefit of implementing the true-up mechanisms rather than interim rates (Xcel recently filed its finalized 2020 sales true-up calculations and that matter is pending before the Commission). Prior to the Commission's order approving the 2021 Stay Out, Xcel submitted a letter on March 3, 2021, indicating that it had inadvertently overstated the interim-rate increase of its pending rate case by approximately $43 million. In so doing, the delta between the 2021 Stay Out and rate case interim rates is smaller than initially projected. Therefore, in a seemingly unusual step, the Commission also noticed a corresponding comment period seeking feedback from parties on:

(1) whether the material in Xcel's letter materially changes the rationale for approving the 2021 Stay Out;
(2) whether the Commission should reconsider its approval of the 2021 Stay Out; and
(3) whether there are other issues or concerns.

Importantly, initial comments are due on April 22, 2021, which appears to match the normal timing for parties to petition for reconsideration of Commission orders pursuant to Minn. R. 7829.3000. Parties will also have the ability to respond by May 3, 2021.

2. Minnesota Power Deferred Accounting Request, PUC Docket No. 20-814

On Thursday, April 1, 2021, the Commission considered Minnesota Power's deferred accounting request. In that request, Minnesota Power sought Commission approval to track lost industrial sales revenue for potential recovery in a subsequent rate case. Various parties filed comments generally questioning/opposing the need for deferred accounting, and whether Minnesota Power's request met the traditional standard for approval of deferred accounting. After review, the Commission denied Minnesota Power's request. In so doing, the Commission reiterated its historically stringent standard for approving deferred accounting requests, seemingly distancing itself from other recent decisions appearing to relax that standard.

A written order on this matter is pending. Parties also expect Minnesota Power will file its next rate case in November 2021, though this result could theoretically alter that timing.

OREGON

PGE and PacifiCorp Submit Annual Net Metering Report – RE 45 and 39

Last week, PGE and PacifiCorp submitted their annual net metering reports for 2020. These reports depict the total number of net metering facilities by resource type and their total estimated generation capacity. The 2020 report for PGE can be located here and the PacifiCorp report can be located here.

Staff Workshop on April 7 in Regard to QF Standard Contracts – AR 631

On Wednesday, April 7, the Oregon Public Utility Commission will hold a closed workshop to discuss major areas of disagreement related to the staff's proposal for proceeding with PURPA-related dockets in 2021. The staff proposal can be located here as well as next steps for public comment periods and future workshops.

Public Hearing on April 6 in Regard to Idaho Power's 2019 IRP – LC 74

On Tuesday, April 6 at 1:30 p.m. PST, the Oregon Public Utility Commission will hold a public hearing to discuss Idaho Power's 2019 Integrated Resource Plan (IRP). The Oregon Public Utility Commission will engage with stakeholders and staff regarding the action plan items published in Idaho Power's second amended 2019 IRP. Idaho Power's proposed action plan can be located on page 7 of the attached filing.

WASHINGTON

Public Workshop on April 6 in Regard to Implementation of the Clean Energy Transformation Act – UE – 210147

On Tuesday, April 6 at 9:00 a.m. PST, the Washington Utilities and Transportation Commission will hold a stakeholder workshop to discuss implementation of the Clean Energy Transformation Act's (CETA) equity and customer benefit mandates. Specifically, the CETA requires utilities to use certain customer benefit/equity indicators in future integrated resource plans and clean energy implementation plans. The workshop agenda can be located here.

NEW YORK INDEPENDENT SYSTEM OPERATOR

1. FERC Issues Order Accepting New York Independent System Operator (NYISO) Tariff Revisions to Implement Participation Model for Co-Located Storage Resources.

On March 30, 2021, Federal Energy Regulatory Commission (FERC) issued an order accepting NYISO's January 29, 2021, tariff revisions to implement enhancements that will enable an Energy Storage Resource (ESR) and a wind or solar Intermittent Power Resource (IPR) to share a common point of injection and participate in the NYISO-administered markets as a Co-Located Storage Resource (CSR). NYISO indicates that this is one of a number of upcoming tariff revisions related to ensuring that resources that share a common point of injection may participate in the market as individual or aggregated resources. The current filing is limited to the co-located operation of an ESR and a wind or solar IPR because: it was the most requested model and because it is feasible to develop the market improvements and implement the revisions by the fourth quarter of 2021.

NYISO proposed tariff revisions to its energy and ancillary services market rules, its metering rules, its Interconnection Process, its Installed Capacity (ICAP) market participation rules, and its market power mitigation measures to accommodate the interconnection and participation of an ESR that is co-located with a wind or a solar IPR as a set of CSRs. The tariff revisions will allow two generators to submit a single, shared interconnection request, or to consolidate two interconnection requests in NYISO's interconnection queue. The two generators in a CSR would share an injection limit determined by the associated interconnection and transmission facilities' physical capabilities and could potentially be less than the combined capability of the two generators in the CSR. The ESR and wind or solar IPR would be disaggregated as distinct generators in the NYISO-administered energy, ancillary services, and ICAP markets. These tariff revisions were uncontested.

FERC accepted these tariff revisions for CSRs, finding them just and reasonable. FERC noted that the tariff revisions will enhance the eligibility and participation of CSR component resources, as well as for ESRs more generally, in NYISO's energy, ancillary services and capacity markets.

As part of its filing package, NYISO proposed a tariff revision to revise how it assesses annual administrative and FERC fees. Specifically, NYISO proposed to revise the definition of Actual Energy Withdrawals in the Services Tariff by adding that withdrawals shall also include the absolute value of negative withdrawals by load for behind the meter generation.

Clean Energy Intervenors contested this proposal, arguing that it will create pancaked administrative fees. FERC rejected Clean Energy Intervenors' protest, finding that the fees are just and reasonable because NYISO proposed to assess charges on the same basis that it already assessed these charges to stand-alone ESRs and to stand-alone wind or solar IPRs. This equal treatment across resources, whether or not they participated in CSRs, was just and reasonable.

FERC also accepted NYISO's proposed effective dates. FERC accepted (1) the proposed new defined terms CSR and CSR Scheduling Limit; (2) the proposed revisions to the interconnection rules; and (3) the proposed revisions to the ICAP mitigation rules effective March 31, 2021. FERC accepted the remaining tariff changes effective on a flexible date between October 1, 2021 and December 31, 2021. NYISO must also make an informational filing on August 1, 2021, regarding NYISO's progress to test and complete the software changes needed to implement its CSR Participation Model and the estimated implementation date.

2. Letter Order Finding NYISO's Proposed Tariff Amendments to Revise the Operating Reserves Demand Curves and to Establish the Process to Procure Supplemental Reserves Deficient.

On March 29, 2021, the Division of Electric Power Regulation – East (Division) issued a letter order indicating that NYISO's tariff revisions to implement the process for procuring operating reserves throughout the New York Control Area were deficient.

The Division seeks information regarding the steps and process NYISO undertakes to procure supplemental reserves, including the triggering condition(s) and the detailed process for approval from the Operating Committee. The Division also requests information regarding the conditions that would necessitate NYISO to propose to procure supplemental reserves for approval from the Operating Committee. Lastly, the Division seeks to understand how NYISO will proceed if it does not obtain Operating Committee approval for a proposal to implement or adjust supplemental reserves at least 30 days prior to being implemented in the wholesale markets.

NYISO has 30 days to respond to the deficiency letter by making a deficiency filing.

3. NYISO Seeks Request for Expedited Clarification of Interim ICAP Demand Curves.

On March 30, 2021, the NYISO filed a request for expedited clarification regarding the interim ICAP Demand Curves that would apply for the upcoming ICAP Spot Market Auctions if the NYISO's proposed ICAP Demand Curves are not accepted by FERC on or before April 13, 2021.

Per its tariff, NYISO's currently effective ICAP Demand Curves expire on May 1, 2021. In its request, NYISO explained that if FERC does not accept the proposal, without modification, by April 13, 2021, NYISO will not be able to implement the new ICAP Demand Curves by May 1, 2021. NYISO stated that in such an instance, it plans to continue to use the currently effective ICAP Demand Curves until the implementation of new ICAP Demand Curves for the 2021/2022 capability year. The NYISO is seeking an affirmative clarification from FERC that such action is reasonable and appropriate.

In the alternative, NYISO requested an expedited waiver of the provisions of Sections 5.14.1.2 and 5.14.1.2.2.5 of its tariff, which specify that the currently effective ICAP Demand Curves expire on May 1, 2021. The waiver would have the same effect as a clarification by allowing NYISO to use its currently effective ICAP Demand Curves until it is able to obtain a final order in the proceeding and implement new ICAP Demand Curves.

NYISO noted that for the 2011/2012, 2012/2013, and 2013/2014 capability years, resolution of the ICAP Demand Curves did not occur prior to expiration of the then-existing ICAP Demand Curves. In those instances, FERC directed NYISO to maintain the then-currently effective ICAP Demand Curves.

FEDERAL ENERGY REGULATORY COMMISSION

1. FERC's next open meeting is April 15, 2021.

2. FERC has extended the timeframe for market-based rate (MBR) sellers to file their baseline filings in compliance with FERC Order No. 860. Order No. 860 will now go into effect on July 1, 2021 and baseline filings will be due by November 2, 2021. The relational database system is open through June 30, 2021 for testing, and then the system

will be open for baseline filings from July through October. FERC has scheduled a technical workshop on April 22, 2021 to discuss the functionality and features of the relational database that will collect certain MBR information.

3. FERC has scheduled a technical conference to discuss electrification and the grid of the future on April 29, 2021.

4. FERC has scheduled a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events on June 1-2, 2021.

5. FERC Issues Order on Initial Decision in Panda Stonewall Reactive Power Rate Case. On March 31, 2021, FERC issued complementary orders related to reactive power rates within PJM Interconnection, L.L.C.'s (PJM) footprint. FERC issued an Order on Initial Decision and Contested Offer of Settlement (Opinion 574) related to Panda Stonewall LLC's (Panda) proposed rate schedule for reactive service and issued an Order Denying Petition for Declaratory Order of the Indicated Generation Owners, of which the parent company of Panda is a member. The Petition for Declaratory Order sought guidance regarding certain cost-based methodologies to compensate generators for providing reactive power service. FERC denied the request, finding that these issues are case-specific and largely addressed in Opinion 574.

   FERC, in Opinion 574, affirmed the Initial Decision in part and reversed in part. Additionally, FERC rejected Panda's unilateral offer of settlement. Major issues within FERC's order include:

   a. Determination of Total Reactive Power Plant Investment. A reactive rate is determined by separately identifying the costs of four groups of plant investments: (1) the generator exciter system; (2) the GSUs; (3) the AEE; and (4) the remaining production plant investment, often referred to as Balance of Plant (BOP). FERC affirmed the Initial Decision's determination that Panda failed to provide sufficient evidence that its major equipment costs assignments were just and reasonable. Panda relied on the analysis of its third-party engineering, procurement and construction (EPC) contractor, which FERC determined was error-filled and inaccurate. FERC distinguished precedent that accepted third-party contractor analysis by showing that here, Panda did not seek a further breakdown of costs from its third-party contractor, its third-party contractor analysis was not subject to audit procedures during the construction period, and that FERC Trial Staff and intervenors provided a better estimate of costs. Parties may still seek to use EPC contracts and third-party contractor analysis to support their reactive power costs, but should follow the standard provided in *Chehalis Power Generating, LP*, 123 FERC ¶ 61,038 (2008), as summarized in Opinion 574.
   b. Indirect Costs. Panda incurred and sought recovery of additional costs outside of the EPC contract. FERC affirmed the Initial Decision that these costs were just

and reasonable, but that Panda's proposed allocation of these costs to the four categories detailed above was unjust and unreasonable. FERC confirmed that these indirect costs should be allocated to all four investment categories based on the ratio of reactive investment to total plant investment.

c. Power Factor. FERC agreed that the facility's nameplate power factor should be used in calculating reactive rates, rejecting the argument from the PJM Market Monitor that the tariff requirements should be used.
d. Accessory Electric Equipment Allocation Factor (AEE Allocation Factor). The AEE Allocation Factor is the ratio of generator and exciter auxiliary load divided by total production plant auxiliary load. This means the numerator is the amount of electricity consumed by the components of the generator responsible for reactive power production, and the denominator is the auxiliary load for the entire plant. The Initial Decision determined that Panda's calculation of the numerator and denominator was unjust and unreasonable. FERC partially reversed the Presiding Judge, finding that Panda's calculation of the denominator using a proxy group of design data was acceptable. FERC upheld the Presiding Judge's determination that Panda incorrectly conflated the power factor of AEE equipment with the facility's power factor when determining the numerator.
e. BOP Allocation Factor. FERC rejected Panda's approach to one component of the BOP Allocation Factor. Panda argued that the maximum MVARs component of the BOP Allocation Factor should reflect the higher of the leading and lagging MVAR output, while FERC Trial Staff argued that it should only be based on lagging output. FERC utilized Trial Staff's methodology, finding that it served the purpose of reactive power compensation: to incentivize investment in equipment related to the production of reactive power, whereas Panda's methodology incentivized the power to absorb reactive power.
f. Firm Fuel Transportation Costs. In this issue of first impression, Panda sought to recover its firm fuel transportation costs as fixed non-fuel O&M expenses in its O&M Production Demand Expense. FERC affirmed the Initial Decision in rejecting these costs as unjust and unreasonable. FERC reasoned that fuel costs are chiefly related to the provision of real power, not reactive power. Further, FERC found that Panda was recovering these costs through heating losses. Accordingly, allowing such recovery of firm fuel transportation costs would result in double recovery.
g. Cost of Capital. Panda proposed use of the capital structure and cost of capital of the Reference Resource from PJM's 2014 cost of new entry (CONE) study as a proxy to derive its cost of capital. FERC affirmed the Initial Decision's determination that use of the Reference Resource from the 2014 CONE study was not proven to be a just and reasonable proxy for setting Panda's ROE and capital structure for a reactive power rate case. FERC found that CONE was not intended to be used for reactive rate cases, but rather to establish the demand curves for the capacity auction. FERC ultimately affirmed the Initial Decision's conclusion that the capital costs of its interconnected utility (Dominion Energy Virginia/North Carolina) are a just and reasonable proxy for Panda's cost of capital, noting that

Panda could have performed its own unit-specific cost of capital analysis but chose not to do so.

h. Unilateral Offer of Settlement. FERC rejected Panda's unilateral settlement offer, finding that it was procedurally improper because it failed to provide other parties the opportunity to have their positions considered. Additionally, FERC rejected the settlement on the merits because it parroted the arguments Panda raised on exceptions to the Initial Decision that were largely not found in Panda's favor in Opinion 574.