REGULATORY UPDATE FOR APRIL 19 (WEEK OF APRIL 12)

CALIFORNIA PUBLIC UTILITIES COMMISSION

New Proposed Decisions and Draft Resolutions[1]

R.13-11-005 (energy efficiency policies). This decision addresses policy issues surrounding the identification of energy efficiency potential and the setting of goals for program administrators to achieve in the design and implementation of energy efficiency programs. First, the decision adopts a new metric, called Total System Benefit, which combines and optimizes the energy and peak demand savings goals, along with greenhouse gas benefits of energy efficiency, into one metric that can be forecasted and tracked. Program administrators will continue to track individual electricity and natural gas savings as well. Next, the decision adopts a new approach to segmenting the energy efficiency program portfolios into programs whose primary purposes are resource acquisition, market support, or equity. A cost-effectiveness threshold will be applied to the resource acquisition programs, since those have readily identifiable costs and benefits that can be quantified. Program administrators will also continue to track the cost-effectiveness of the overall portfolio. The budget amount devoted to the market support and equity programs will be limited to 30% of the total budgets, except in the case of the regional energy network program administrators, who will not be subject to these limits because of the different nature of their portfolios. The evaluation, measurement, and verification budget will remain unchanged at 4% of the total portfolio. Further, this decision addresses changes to the rolling portfolio framework and regulatory processes as proposed by stakeholders in the context of the California Energy Efficiency Coordinating Committee and submitted to the Commission. The current rolling portfolio process originally adopted in Decision (D.) 15-10-028 is modified to require an eight-year business plan filing and four-year program portfolio filing, with updates to the potential and goals, as well as technical inputs and avoided costs, every two years.

Voting Meetings

April 15 Voting Meeting

The CPUC held a voting meeting on April 15, 2021. The agenda included the following items:

Item 9: Draft Resolution E-5118. By this resolution, the CPUC approves, with two adjustments, additions to several Southern California Edison Company (SCEC) net energy metering and virtual net energy metering tariffs related to customers who wish to replace their

[1] Per California Public Regulatory Commission (the 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.

renewable distributed generation systems destroyed as a result of disasters. The CPUC authorizes SCEC to modify certain tariffs for disaster-impacted customers to: allow sizing replacement renewable distributed generation systems to the estimated load, remove the 10%/1 kilowatt system modification threshold, and exempt customers from the interconnection application fee when reapplying for service. Also, the CPUC authorizes SCEC to update its interconnection application forms to provide a means for disaster-impacted customers to identify themselves during the interconnection process. The CPUC requires SCEC to allow disaster-impacted customers four years to apply for interconnection. **Approved.**

Item 13: Draft Resolution E-5119. This draft resolution would approve three PG&E power purchase agreements with Frito-Lay, Inc.; Olsen Power Partners; and Hydro Sierra Energy, LLC, and associated cost recovery. **Approved.**

Item 19: Draft Resolution E-5139. This draft resolution approves five contracts totaling 140 MW for incremental system reliability resources that San Diego Gas & Electric Company (SDG&E) procured through its System Reliability Request for Offers solicitation in 2020. SDG&E undertook this procurement to meet its 2021 incremental procurement requirements pursuant to D. 19-11-016 in the Integrated Resource Plan Rulemaking, 16-02-007. This resolution approves the contracts without modification. **Approved.**

The five contracts are described below:

Project Name (Counterparty)	**Technology**	**Size (MW)**	**Contract Type**	**Location**	**In or Adjacent to DAC?**	**Commercial Online Date**	**Term (Years)**
Johanna Energy Center (Calpine)	Standalone Lithium Ion Battery	20	PPA	Orange County	Yes	8/1/22	10
North Johnson Energy Center (Wellhead)	Standalone Lithium Ion Battery	25	PPA	San Diego County	Yes	6/1/22	15
BCE Los Alamitos (Bright Canyon)	Hybrid Solar Photovoltaic with Lithium Ion Battery	10	PPA	Orange County	No	6/1/22	10
Ortega Grid (Able Grid)	Standalone Lithium Ion Battery	10	RA-only	Riverside County	Yes	6/1/22	10
Desert Peak Energy Storage II (Next Era)	Standalone Lithium Ion Battery	75	PPA	Riverside County	No	6/15/23	15

Item 22: Draft Resolution E-5140. This resolution approves six contracts for incremental system reliability resources that PG&E procured through its System Reliability Request for Offers – Phase 2 solicitation in 2020. PG&E undertook this procurement to meet its 2022 and 2023 incremental procurement requirements pursuant to D. 19-11-016 in the Integrated Resource

Plan Rulemaking, 16-02-007. This resolution approves the contracts without modification. **Approved.**

The six contracts are described below:

Counterparty (Project Name)	Technology	Size (MW)	Location and DAC Designation	Contract Type	Initial Delivery Date	Term (Years)
Nexus Renewables U.S. Inc. (AMCOR)	Standalone Lithium Ion Battery	27	Fairfield, Solano County, CA (Not in DAC)	BTM LTRAA	8/1/2022	15
Lancaster Battery Storage, LLC (Lancaster Battery Storage)	Standalone Lithium Ion Battery	127	Lancaster, Los Angeles County, CA (DAC Adjacent)	LTRAA with ES	8/1/2022	15
LeConte Energy Storage, LLC (LeConte Energy Storage)	Standalone Lithium Ion Battery	40	Calexico, Imperial County, CA (In DAC)	LTRAA	8/1/2022	15
North Central Valley Energy Storage, LLC (North Central Valley Energy Storage)	Standalone Lithium Ion Battery	132	Linden, San Joaquin County, CA (DAC Adjacent)	LTRAA with ES	8/1/2023	15
Daggett Solar Power 2, LLC (Daggett 2 BESS)	Standalone Lithium Ion Battery	46	Daggett, San Bernardino County, CA (In DAC)	LTRAA	8/1/2023	15
Daggett Solar Power 3, LLC (Daggett 3 BESS)	Standalone Lithium Ion Battery	15	Daggett, San Bernardino County, CA (In DAC)	LTRAA	8/1/2023	15

Item 23: Draft Resolution E-5124. This resolution approves, with modification, CleanPowerSF's Advice Letter (AL) 12-E, East Bay Community Energy's AL 14-E/E-A, Marin Clean Energy's AL 42-E/E-A/E-B, Peninsula Clean Energy's AL 11-E, and San Jose Clean Energy's AL 15-E to create tariffs to implement the Disadvantaged Communities Green Tariff and/or Community Solar Green Tariff programs. **Approved.**

Item 36: Proposed Resolution M-4852. This resolution is issued to PG&E in accordance with D. 20-05-053, which gave Commission approval of PG&E's bankruptcy plan of reorganization with conditions and modifications. The decision established an Enhanced Oversight and Enforcement Process allowing the Commission to take additional steps to ensure PG&E is improving its safety performance if specific Triggering Events occur. The steps range from Step 1, which contains enhanced reporting and oversight requirements, to Step 6, involving the potential revocation of PG&E's ability to operate as a California electric utility. This resolution invokes Step 1, with regard to PG&E's insufficient progress with risk-driven wildfire mitigation efforts, and requires PG&E to submit a Corrective Action Plan within 20 days of the resolution effective date. **Approved.**

April 22, 2021 Voting Meeting

The Commission also has a voting meeting scheduled for April 22, 2021. The following item is included in the agenda:

Item 5: A.20-04-023 (PG&E Stress Test). California Public Utilities Code Sections 451.2(c) and 850.1(a) authorize the Commission to issue a financing order to allow for recovery of costs that exceed the maximum amount a utility can pay without harming customers, as determined pursuant to Section 451.2(b). The Commission issued a rulemaking in 2019 to, among other things, guide the evaluation of an electrical corporation's financial status and the determination of the maximum amount the corporation can pay for 2017 catastrophic wildfire costs. D. 19-06-027 adopted a methodology for conducting a financial "Stress Test" to implement the directives of Section 451.2. PG&E's application requested that the Commission apply that methodology because it has incurred costs and expenses from 2017 wildfires that should be disallowed, and it seeks to issue recovery bonds for a portion of those costs and expenses pursuant to Sections 451.2(c) and 850 et seq. This decision determines that Pacific Gas & Electric Company satisfies the Stress Test methodology adopted in D. 19-06-027 and that $7.5 billion of 2017 catastrophic wildfire costs and expenses may be financed through the issuance of recovery bonds pursuant to Public Utilities Code Section 850 et seq.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

Board of Governors Meeting

The next Board of Governors' meeting is scheduled for April 21, 2021. The agenda may be found here: FINAL Board of Governors Meeting Agenda (caiso.com). The Board will consider a decision on market enhancements for summer 2021 readiness.

Stakeholder Initiatives: Upcoming Meetings and Deadlines

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 (FERC) in April 2021.

Final 2022 and 2026 Local Capacity Technical Study Results. Written comments on the final study results are due April 21.

Draft 2022 Flexible Capacity Needs Assessment. The California ISO will hold a public stakeholder call on April 22, 2021, to discuss the Draft 2022 Flexible Capacity Needs Assessment. Written comments are due April 30, 2021.

CALIFORNIA ENERGY COMMISSION

At its April 14, 2021 Business Meeting, the California Energy Commission (CEC) adopted 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. The next CEC Business Meeting is scheduled for May 12, 2021.

MINNESOTA PUBLIC UTILITIES COMMISSION

1. Minnesota Public Utilities Commission Inquiry into Actions by Electric and Natural Gas Utilities in Light of the COVID-19 Pandemic Emergency

On April 15, 2021, the Minnesota Public Utilities Commission (Commission) met to consider utilities' transition plans addressing the end of the current Minnesota peacetime emergency and the anticipated impacts on residential ratepayers. After discussion, the Commission adopted the consumer advocates' transition plan proposal and set additional reporting requirements for multiple utilities. Additionally, at the appropriate time, the Commission will work with the Department of Commerce to issue a press release notifying customers that utility disconnection and collection practices will be resuming.

2. Minnesota Power 2020 Renewable Resource Rider Solar Factor Docket

On April 15, 2021, the Commission met to consider Minnesota Power's 2020 solar renewable factors within its Renewable Resource Rider. Ultimately, the Commission approved Minnesota Power's petition, including cost recovery with revenue requirements of $7,150,343 for Camp Ripley, $16,984 for the Community Solar Garden, and $3,038,222 for Solar Sense, for a total recovery of $9,437,440. Additionally, the Commission approved Minnesota Power's proposed factor of Camp Ripley Costs and a 0.2917% carrying charge.

3. Minnesota Power Rider for Boswell Center Unit 4 Emissions Reduction Rider and 2021 Factor

At a hearing on April 15, 2021, the Commission met to analyze Minnesota Power's request to end the Boswell Energy Unit 4 (BEC4) rider credit. After review, the Commission approved Minnesota Power's request to make a one-time charge to a specific group of customers to recover the remaining BEC4 balance. The Commission also approved Minnesota Power's request to end the BEC4 bill credit and make a one-time credit to close out the tracker balance for another customer group. Minnesota Power will subsequently file compliance filings detailing the amounts charged/credited to specific customer groups. Additionally, Minnesota Power indicated that it will make a supplemental filing pertaining to one customer class in August 2021.

OREGON

OPUC Staff Requests New Rulemaking with Respect to Community Solar Program – AR 644

Last Wednesday, the Oregon Public Utility Commission (OPUC) staff filed a report recommending new rulemaking related to Oregon's Community Solar Program (CSP). The rules would address certification revocation for project managers who fail to comply with CSP guidelines, as well as establish a dispute resolution process for project managers who have complaints with other managers in the program. The initial filing can be located here.

OPUC Public Meetings This Week

On Tuesday, April 20, the OPUC will hold a public meeting to discuss a wide range of dockets. The agenda includes a discussion on project pre-certification in the Oregon CSP (docket UM 1930) scheduled at 9:30 a.m. and a discussion on PGE's 2019 Integrated Resource Plan (docket LC 73) which is scheduled for 1:30 p.m.

Additionally, later in the week on Thursday, April 22 at 1:30 p.m., the OPUC will host a public meeting to discuss rulemaking related to the use of renewable energy certificates in Oregon's Renewable Portfolio Standard (docket AR 617).

Senate Committee Meeting This Week with Respect to HB 2109

On Tuesday, April 20 at 1:00 p.m., the Senate Committee on Energy and the Environment will hold a public hearing to discuss HB 2109, which is a procedural rule that modifies the definition of "renewable energy facility" for county permitting processes. This bill has already been passed in the House. The complete measure history is located here.

NEW YORK PUBLIC SERVICE COMMISSION

1. New York Public Service Commission (NYPSC) Approves Consolidated Edison Company of New York Inc.'s (Con Edison) Transmission Reliability and Clean Energy Projects (TRACE Projects)

On April 15, 2021, the NYPSC approved Con Edison's request to recover costs associated with its trifecta of transmission projects that are collectively known as the TRACE Projects. The TRACE Projects are composed of the Rainey to Corona Project, the Gowanus to Greenwood Project, and the Goethals to Greenwood Project. The Rainey to Corona Project is expected to be operational at the start of summer 2023 while the other two projects are expected to be operational at the start of summer 2025.

NYPSC held that these projects will facilitate the integration of new renewable generation into the grid and that these projects are needed for reliability in 2023 and 2025. NYPSC determined that the TRACE Projects will help address deficiencies in two of Con

Edison's transmission load areas because of the retirement of peaking fossil fuel-fired generation.

2. Deal Struck for Closure of Indian Point Nuclear Power Facility

On April 15, 2021, Governor Cuomo announced a joint proposal with Holtec International and its subsidiaries to close the Indian Point nuclear power facility in the lower Hudson Valley. Interested parties may comment on the joint proposal and the NYPSC will subsequently review and consider the joint proposal.

In 2017, Entergy agreed to close the two remaining operating units at the facility. Subsequently, Entergy and Holtec sought approval to transfer the facility to Holtec for decommissioning. The joint proposal represents the culmination of negotiations between various stakeholders regarding this transfer and the funding for decommissioning activities. The joint proposal also resolves the pending litigation over the Nuclear Regulatory Commission's approval of the transfer from Entergy to Holtec.

The joint proposal is intended to ensure that the trust funds that were capitalized by New York ratepayers are sufficient to ensure safe and proper decommissioning. Specifically, the joint proposal (i) places certain minimum balance restrictions on Holtec; (ii) requires funding towards state and local emergency management response; (iii) ensures proper financial and project reporting to the state; and (iv) ensures site restoration is approved by the New York State Department of Environmental Conservation.

3. NYPSC Adopts New Data Access Framework

On April 15, 2021, the NYPSC adopted a new framework for data access that is meant to enhance customer protections and ensure that New York will meet its clean-energy goals. The framework creates a risk-based approach and is meant to serve as a single source for statewide data access requirements. NYPSC states that this centralized system will ease burdens on utilities while benefiting ratepayers. NYPSC states that the framework will provide uniform and consistent guidance on the availability of energy-related data, which will enable market participants to "deliver smart, economically sound energy solutions" to meet New York's climate goals. The framework also provides processes for data access and standardizes certain privacy, cybersecurity, and quality requirements for access to energy-related data.

4. NYPSC Issues Order Directing Modifications to Energy Storage Solicitations

On April 15, 2021, the NYPSC granted in part and rejected in part New York's electric investor-owned utilities (IOUs) petition for modifications to NYPSC's December 18, 2018, Energy Storage Order (Petition). The Energy Storage Order directed the IOUs to competitively procure dispatch rights for bulk-level energy storage systems to be operational by December 31, 2022. The IOUs conducted the first round of solicitations throughout 2019 and the first part of 2020, but did not meet the minimum statewide target for bulk-level energy storage systems.

On October 30, 2020, the Joint Utilities filed the Petition requesting that the NYPSC modify the Energy Storage Order in order to improve the procurement results. The Petition stated that negotiations were continuing with winning bidders from the first solicitation round, but that the IOUs were not able to collectively attain the full target set in the Energy Storage Order.

In the Petition, the IOUs requested three changes to be incorporated into the next solicitation: (1) an extension of the in-service date from December 31, 2022, to no later than December 31, 2025; (2) an extension of the maximum dispatch rights contract duration from the current "up to seven years" to "up to ten years"; and (3) an additional procurement option whereby the utility could solicit and purchase storage projects from a developer upon project operation, and after an established ownership period could seek to sell the storage project if the sale would produce a ratepayer benefit.

In its April 15 order, the NYPSC granted the extension request, finding that it was not feasible for the IOUs to select and complete negotiations with winning bidders, and have projects permitted, constructed, and in service by December 31, 2022. The NYPSC also granted the request to extend the maximum contract duration from seven to ten years. However, the NYPSC rejected the request for an IOU ownership option in procuring energy storage resources in the next solicitation round. The NYPSC reasoned that there exists a strong market position in achieving its energy storage deployment goals, and accordingly, it should be conservative when considering utility ownership. The NYPSC held that there was no reason to modify its preference for third party development of these projects in rejecting this proposal.

NEW YORK INDEPENDENT SYSTEM OPERATOR

1. FERC Issues Order on New York Independent System Operator (NYISO) Petition for Declaratory Order Regarding Order No. 1000 Transmission Upgrades

On April 15, 2021, FERC issued an Order granting in part and denying in part NYISO's August 18, 2020, Petition for Declaratory Order seeking (1) confirmation that the New York Transmission Owners (NYTOs) have a federal right of first refusal (ROFR) under NYISO's foundational agreements and section 31.6.4 of NYISO's Open Access Transmission Tariff (OATT) to build, own, and recover the cost of upgrades to their existing transmission facilities, as permitted under Order No. 1000; (2) confirmation that, if an NYTO exercises its federal ROFR for upgrades to its existing transmission facilities, the NYTO should be treated under the existing OATT as a Developer for the upgrade portion of the transmission project; and (3) clarification of the scope of the definition of "upgrade" under the OATT (Petition).

After reviewing the foundational agreements between the NYTOs and NYISO, FERC confirmed that the provision within these agreements that transmission owners continue to own their transmission facilities and retain the right to modify their transmission facilities and the right to build, maintain, replace, etc. all or any part of their assets encompasses transmission upgrades. Accordingly, FERC granted this clarification of a federal ROFR for NYTOs with respect to transmission upgrades.

FERC denied NYISO's request that, under Order No. 1000, NYTOs undertaking upgrades should be treated as Developers, for that upgrade portion of the transmission project for purposes of cost allocation. NYTOs sought this treatment so that they would become a sponsor of the upgrade portion of any transmission project selected in the regional transmission plan for purposes of cost allocation. FERC held that to be a Developer designation in Order No. 1000 was exclusive to entities that submit a bid to sponsor or propose an Order No. 1000 transmission project, not an NYTO that proposes an upgrade to its own existing transmission facility that is included in another Developer's selected Order No. 1000 project.

Lastly, FERC granted in part and denied in part the clarifications regarding the scope of the definition of "upgrade." FERC granted the request to clarify that a new transmission facility that requires the retirement or decommissioning of an NYTO's existing transmission facility and connects to the transmission system in a different configuration than the original facility is not an upgrade, but a new transmission facility. Further, FERC declined to opine on the second requested clarification regarding the process for such decommissioning activities, finding that NYISO had not provided sufficient information on the matter.

FEDERAL ENERGY REGULATORY COMMISSION

1. 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.

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

3. 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.

4. FERC issued a supplemental NOPR proposing to modify its March 2020 plan to revise its electric transmission incentives policy. The supplemental NOPR proposes to codify FERC's current practice of granting a 50-basis-point increase in return on equity as an incentive for utilities that join a transmission organization and make the incentive available only for the first three years after the utility transfers operational control of its facilities to the transmission organization. The previous March 2020 plan would have increased the incentive and extended it indefinitely. Chairman Glick characterized the March 2020 plan as a "handout," not an incentive, for transmission utilities. The supplemental NOPR also seeks comment on whether the incentive should be available solely to transmitting utilities that join a transmission organization voluntarily.

5. FERC issued a policy statement on carbon pricing in organized wholesale markets. The statement clarifies how FERC will consider market rules proposed by regional grid operators that seek to incorporate a state-determined carbon price in organized wholesale electricity markets. The policy statement explains FERC's jurisdiction under Section 205 of the Federal Power Act and presents a framework to review any wholesale market rules incorporating a state-determined carbon price, but it also affirms that whether and how a state chooses to address greenhouse gas emissions is a matter exclusively within that state's jurisdiction.

6. FERC assessed a $15 million penalty against Boyce Hydro Power LLC for dam safety violations at three of the company's hydroelectric projects in Michigan. The violations followed significant flooding and a dam breach in May 2020 that resulted in substantial damage to the surrounding communities.