STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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April 3, 2020 **Agenda ID #18311**
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 18-07-017:

This is the proposed decision of Administrative Law Judge Peter Allen. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's May 7, 2020 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.2(c)(4)(B).

/s/ S. PAT TSEN for
Anne E. Simon
Chief Administrative Law Judge

AES:avs

Attachment

Decision **PROPOSED DECISION OF ALJ ALLEN** **(Mailed 4/3/2020)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Continued Implementation of the Public Utility Regulatory Policies Act and Related Matters.	Rulemaking 18-07-017

DECISION ADOPTING A NEW STANDARD OFFER CONTRACT FOR QUALIFYING FACILITIES OF 20 MEGAWATTS OR LESS PURSUANT TO THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

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DECISION ADOPTING A NEW STANDARD OFFER CONTRACT FOR QUALIFYING FACILITIES OF 20 MEGAWATTS OR LESS PURSUANT TO THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Summary

This decision adopts a new standard offer contract that will be available to any Qualifying Facility (QF) of 20 megawatts or less seeking to sell electricity to a Commission-jurisdictional utility pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA).[1] Consistent with the PURPA implementing regulations, the standard offer contract adopted by this decision includes two pricing options for both capacity and energy for a total of four avoided cost rates: a rate determined at the time of contract execution for both capacity and energy, and a rate determined at the time of product delivery for both capacity and energy.[2]

The maximum term of this standard offer contract is twelve years for new facilities and seven years for existing facilities, and the contract shall be made available to QFs of 20 megawatts (MW) or less until suspended by the Commission's Executive Director.

The availability of this new standard offer contract does not change or interfere with any of the Commission's other PURPA programs, including, without limitation, any existing or available PURPA contracts or with any aspect

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[1] PURPA is codified generally at 16 U.S.C. §§ 824a-3 and 2601. Various provisions appear elsewhere in the United States Code. The federal regulations implementing PURPA are available at 18 C.F.R. Subchapter K starting at Part 290. QF means a small power production facility or a cogeneration facility that meets the criteria under Subpart B starting with Section 292.201 of these regulations 18 C.F.R. § 292.101.

[2] *See* 18 C.F.R. § 292.304(d)(2).

of the Qualifying Facility (QF) Settlement approved in Decision (D.) 10-12-035 as modified by D.15-06-028 (QF Settlement). Consequently, after adoption of the new standard offer contract required by this decision, Investor Owned Utilities must continue to provide QFs the option of executing any existing PURPA contract that they qualify for, including, without limitation, the QF Settlement standard offer contract adopted in D.10-12-035 (QF Settlement SOC).

This decision also adopts an as-available energy price to be paid at the time of delivery where a QF has opted to sell as-available energy to the utility without a contract. (18 C.F.R. § 292.304(d)(1).) The price for as-available energy is based on hourly locational marginal prices (LMPs) from the California Independent System Operator Corporation's (CAISO's) day ahead market.

This proceeding remains open to consider, as necessary, whether any further action is required to comply with PURPA, particularly in light of the pending Notice of Proposed Rulemaking issued by FERC.[3]

1. Background

1.1. The Commission's Implementation of PURPA

As described in the Order Instituting Rulemaking (OIR) initiating this proceeding, this Commission has a long history of implementing PURPA over nearly four decades, resulting in more than 4,000 megawatts (MWs) of QF power in operation. (OIR at 2.) Because the OIR provides an extensive description of the Commission's past implementation of PURPA (OIR at 2-7), we will not repeat it here in detail, but note that the OIR recognized that a federal court

[3] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* 84 Fed. Reg. 53,246 (October 4, 2019).

found that the QF Settlement SOC did not comply with PURPA because it "failed to provide QFs the option to choose energy rates determined either at the time of contract execution or at the time of product delivery as required by 18 C.F.R. §§ 292.304(d)(2)(i) and (ii)." (OIR at 6-7 referring to *Winding Creek Solar LLC v. Peevey*, 293 F.Supp.3d 980, 990-91 (N.D. Cal. 2017) (*Winding Creek Order*), aff'd sub nom. *Winding Creek Solar LLC v. Peterman*, 932 F.3d 861 (9th Cir. 2019).) As stated in the OIR, as a consequence of this finding, the court also found that the Commission's Renewable Market Adjusting Tariff (ReMAT) program did not comply with PURPA because there is a cap on procurement under ReMAT and because the price that results from the ReMAT auction is not an avoided cost rate.[4]

The OIR also noted that:

> In light of the *Winding Creek Order*, this Rulemaking considers adoption of a New QF SOC[5] with price terms as specified in FERC's PURPA regulations at 18 C.F.R. § 292.304(d)(2) and available to any QF of 20 MW or less seeking to sell electricity in California pursuant to PURPA.

(OIR at 6-7.)

1.2. Procedural Background

The Commission opened this proceeding with an OIR issued on August 1, 2018. Attached to the OIR was a proposal by the staff of the

[4] The ReMAT program requires IOU procurement contracts for small renewable generators up to 3MW capacity, with a statewide program cap of 750 MW. It was enacted in accordance with Pub. Util. Code § 399.11 et seq. through Commission decisions D.12-05-035, D.13-01-041 and D.13-05-034. The *Winding Creek Order* enjoins the Commission from continuing to apply the ReMAT Program as implemented by these Commission decisions.

[5] "QF SOC" is Qualifying Facility Standard Offer Contract.

Commission's Energy Division: "Proposal to Update Avoided Cost Pricing for Qualifying Facilities of 20 MW or Less" (Staff Proposal).

Comments on the Staff Proposal and the OIR Preliminary Scoping Memo's list of issues were filed by The Utility Reform Network (TURN), Winding Creek Solar LLC (Winding Creek), Independent Energy Producers Association (IEP), Solar Energy Industries Association (SEIA), California Wind Energy Association (CalWEA), Clean Coalition, Green Power Institute (Green Power), the Commission's Public Advocates' Office (Cal Advocates), California Association of Small and Multi-Jurisdictional Utilities (CASMU),[6] the ReMAT Developers,[7] and the Investor Owned Utilities.[8] Reply comments were filed by the Investor Owned Utilities, SEIA and the ReMAT Supporters.[9]

A prehearing conference (PHC) was held on September 27, 2018 to discuss the issues and to address the procedures and schedule for this proceeding. At the PHC, a number of parties requested that a workshop be held. (Transcript v. PHC at 9-14.) No party requested or expressed a need for evidentiary hearings. (*Id.* at 6-7.) A workshop was held on October 18, 2018. A Scoping Memo and Ruling was issued on November 2, 2018.

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[6] CASMU includes Bear Valley Electric Service, a division of Golden State Water Company, Liberty Utilities (CalPeco Electric) LLC, and PacifiCorp, d.b.a. Pacific Power.

[7] The ReMAT Developers include Solar Electric Solutions, LLC; APT Solar Company; Division Solar, LLC; Poco Power, LLC; and ImMODO Development LLC,

[8] The Investor Owned Utilities include Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

[9] The ReMAT Supporters include the ReMAT Developers, with the addition of: JTN Energy; Utica Water and Power Authority; Association of California Water Agencies (ACWA); CalWEA; and Vejas Energy, LLC.

In response to the Scoping Memo and Ruling, comments were filed on November 14, 2018 by CASMU, Green Power, Winding Creek, and jointly by the Investor-Owned Utilities and certain QF Parties[10] (together "Joint Parties"). Reply comments were filed on November 28, 2018 by TURN, Green Power, Cal Advocates, Winding Creek, and the Joint Parties.

On February 15, 2019, Pacific Gas and Electric Company (PG&E) filed a Motion to File Supplemental Comments and Supplemental Comments regarding the need to modify the New QF SOC to address its filing for Chapter 11 bankruptcy protection on January 29, 2019. On April 26, 2019 Green Power filed a Motion for Leave to File Report in order to add to the record its own report "*A Modern Cinderella Story: Assessing the state of California's "community-scale" renewable energy market.*" Green Power's Motion was opposed by Cal Advocates and the three Investor Owned Utilities. PG&E's and Green Power's Motions are denied.

On October 22, 2019, Administrative Law Judge (ALJ) Allen issued a Ruling setting forth information on the contract duration for new electric generation projects in the last several years and providing an opportunity for Parties to file and serve supplemental comments to enable the Commission to determine the most appropriate term length for SOCs for new QF facilities. Recently executed contracts that were included in the ALJ Ruling had terms ranging from 10 to 20-years.

[10] The QF Parties include APT Solar Company; ACWA; CalWEA; the Clean Coalition; Division Solar, LLC; Poco Power, LLC; Solar Electric Solutions, LLC; and Utica Water and Power Authority.

In response to the ALJ Ruling, comments were filed on November 7, 2019 by Green Power, Winding Creek, and jointly by the Investor-Owned Utilities. Reply comments were filed on November 15, 2019 by Winding Creek, Cal Advocates, and jointly by the Investor-Owned Utilities, and on November 18, 2019, by Green Power.

On February 10, 2020, the Commission issued an Order Extending Statutory Deadline, extending the statutory deadline for resolving this proceeding from January 25, 2020, to July 25, 2020.

2. Issues to Address

The Scoping Memo in this proceeding quoted the OIR initiating this proceeding, stating:

> The scope of this proceeding is intended to be narrow; we are considering adoption of (1) a New QF SOC containing avoided costs rates required by federal regulations, and (2) adoption of a price to be paid at the time of delivery where a QF has opted to sell as-available energy to the utility without a contract. (Scoping Memo at 3, quoting OIR at 8.)

The Scoping Memo also reiterated the following issues that the OIR specifically identified to be addressed:

> 1. What is the appropriate avoided cost for energy where a QF elects to be paid a price determined at the time of contract execution?
>
> 2. What is the appropriate avoided cost for capacity where a QF elects to be paid a price determined at the time of contract execution?
>
> 3. What is the appropriate avoided cost for energy where a

QF elects to be paid a price determined at the time of delivery?

4. What is the appropriate avoided cost for capacity where a QF elects to be paid a price determined at the time of contract delivery?

5. What is the appropriate avoided cost calculated at the time of delivery for as-available energy sold by a QF to the utility without a contract?

6. Does PURPA require that any of the non-price terms of the Standard Contract for QFs 20 MW or Less[11] be modified before they are incorporated into the New QF SOC?

7. Are there any other issues that the Commission must address to adopt a New QF SOC that complies with PURPA? (Scoping Memo at 3-4, quoting OIR at 8-9.)

The Scoping Memo also found that two additional issues identified by the parties fell within the scope of the proceeding: 1) cost allocation, and 2) the duration of the contracts and how long they would be available. (Scoping Memo at 4.)

The Scoping Memo acknowledged that several parties at the October 18, 2018 workshop circulated and discussed a preliminary term sheet for a possible settlement. The Scoping Memo advised: "A settlement in this proceeding is encouraged. Parties may either submit a proposed settlement

[11] The term "Standard Contract for QFs 20 MW or Less" refers to the standard offer contract set forth as Exhibit 6 to Attachment A of D.10-12-035. This contract - known as the "Standard Contract for QFs 20 MW or Less" - was developed as part of the QF settlement approved in D.10-12-035 (QF Settlement), and will remain unchanged and available to QFs of 20 MW or less. (*See* OIR at 1.)

pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure, or may include a joint proposal in their November 14, 2018 comments." (Scoping Memo at 5.)

3. Parties' Comments

The Staff Proposal attached to the OIR proposed four avoided cost pricing methodologies for the new standard offer contract for QFs 20 MW or less (New QF SOC) – one each for energy and as-available capacity at both time of delivery and time of contract execution. All of the Staff Proposal's energy prices are based on the price paid, at a specific location, to all resources available in the market at that location – including both renewable and fossil fuel generators. Proposed prices for energy at the time of contract execution were based on an average of three years of historic publicly available CAISO market prices at the default load aggregating point (DLAP) or the LMPs, in order to account for anomalous years (through averaging), while still reflecting relatively current actual prices. Proposed prices for capacity at the time of contract execution were based on a choice between using either an average of publicly available forward-looking resource adequacy prices or the capacity prices provided in the QF Settlement SOC. Proposed prices for energy at the time of delivery were based on publicly available CAISO market prices that will be known at the time of delivery. Proposed prices for capacity at the time of delivery were based on an average of publicly available resource adequacy prices updated annually. For all non-price terms, the Staff Proposal proposed to start with those provided in the QF Settlement SOC, and sought party comments on which of those terms required revision. (OIR at 1-2; Scoping Memo at 3-4.)

The Joint Parties' proposal filed November 14, 2018 (Joint Proposal), appears to have evolved from discussions at the October 18, 2018 workshop. The Joint Proposal explains that following the October 18, 2018 workshop, the Investor Owned Utilities distributed their then-current proposal for New QF SOC prices and terms to all the parties on the service list, and likewise noticed and conducted an all-party conference call on October 26, 2018 to afford parties an opportunity to ask questions and provide feedback on the proposal. (Joint Proposal at 2.) Like the Staff Proposal, the Joint Proposal's energy pricing suggestions rely on aggregated CAISO market prices paid to all resources available in a specific location, and generally rely on an average of historic or forward-looking market prices for all but the price for energy at time of delivery, which is based on CAISO market prices at that time. However, the Joint Proposal advocates for use of LMPs, rather than the more aggregated prices at the DLAP, because, among other things, LMPs more accurately reflect the value of generation in a particular area. (Joint Proposal at 4-6.)

In contrast to the QF Settlement SOC's 7 and 12 year terms, the Joint Proposal suggests a twelve month minimum and thirty six month maximum term. (Joint Proposal at 3-4.) It does not specify if the terms would apply equally to existing or new QFs. It justifies this shorter term for the New QF SOC as, among other things, a mechanism to mitigate the uncertainty and risk from significant changes that have occurred and will occur shortly in the energy markets, including the impacts of Community Choice Aggregators (CCAs). (Joint Proposal at 3-4.)

The Joint Proposal supports using many of the non-price terms of the QF Settlement SOC in the New QF SOC (Joint Proposal at 3-4), but also proposes that some terms should be changed or clarified. Specifically, the Joint Proposal advocates for the use of Net Qualifying Capacity (NQC) to measure capacity, with the understanding that:

> Buyer shall compensate Seller for the NQC value provided by Seller and available to meet the Buyer's monthly RA requirement. If Seller's generating facility is on outage or otherwise unable to provide RA in a particular month, Buyer will not have an obligation to provide any substitute RA or minimize any Resource Adequacy Availability Incentive Mechanism (RAAIM) or CAISO charges applicable to the Seller, for which the Seller will be responsible.

(Joint Proposal at 6.)

The Joint Proposal also proposes changes or clarifications to the timeframes for on-boarding generation, contract termination rights (there are none), economic curtailment, cost allocation for customer departures, and the length of time the New QF SOC should be available. (Joint Proposal at 7-8.) The Joint Proposal also requests that the Commission lift the suspension on ReMAT "without delay." (*Id.* at 8-9.)

TURN and Cal Advocates endorse portions of both the Staff and Joint Proposal, but also identify concerns and implementation issues. For example, TURN supports the Joint Proposal, but only as an interim solution. TURN explains:

> …[T]he proposed energy pricing is consistent with TURN's comments on the staff proposal, and the proposed cost allocation method resolves concerns TURN raised during the workshop on October 18, 2018. However, as anticipated by

> the Joint Proposal, TURN supports the Joint Proposal only as an interim, non-precedential resolution of such issues. Given this caveat, TURN believes the Joint Proposal reasonably resolves the general issues raised by the Commission and specific issues raised by parties to this Rulemaking.

(TURN Reply Comments at 2, footnotes omitted.)

Cal Advocates "does not object" to the terms set forth in the Joint Proposal, and supports the Joint Proposal's cost allocation recommendation, but notes that the Joint Proposal only addresses the first two of the OIR's objectives: to establish energy and capacity pricing at the time of contract execution, but fails to address pricing at the time of delivery. (Cal Advocates Reply Comments at 1-2.) Cal Advocates correctly observes that the Commission must address all the objectives set forth in the OIR.

Winding Creek argues that the Staff Proposal is unlawful and discriminatory because it will not encourage QF development. (Winding Creek August 31, 2018 Comments at 5-7.) It claims that "[t]he Commission and the utilities regularly use computerized forecasting models, but yet here the Staff Pricing Proposal completely abandons the modelling used in energy planning." (*Id*. at 6.)

Winding Creek believes that the Commission should modify those provisions of the ReMAT program that the District Court found did not comply with PURPA, rather than focus on developing a new standard offer contract. (Winding Creek Opening Comments at 2-3.) Winding Creek argues that "any state rule that does not *foster* electric generation by QFs conflicts with PURPA and is necessarily preempted." (*Id.* at 4, emphasis in original.)

Regarding the Joint Proposal, Winding Creek objects to its maximum three-year term because it would make a project "unfinanceable and is just another unlawful cap. The FERC has ruled that the term must [] at a minimum be equal to what is needed to finance the project. *See, Windham Solar LLC,* 157 FERC ¶61,134 (2016)." (*Id.* at 6.) Winding Creek also objects to basing a price forecast on a "3-year look back," on the basis that 18 C.F.R. § 292.304(d)(2)(ii) requires a forward-looking forecast and that looking backwards 3 years using historic costs is not a forecast of future avoided costs. (*Id*. at 3 and 6.) Winding Creek's Reply Comments raise no new issues.

Green Power objects to both the Staff and Joint Parties' Proposals. (Green Power Opening Comments at 1-4.) Green Power emphasizes that this proceeding will have "strong national implications" and claims that the Staff Proposal is legally deficient because it does not discuss the likely impact of its pricing proposals and does not compare its proposed pricing with other pricing options. (*Id*. at 2.) It also claims that the Staff Proposal's claim that "the calculated 3-year average day-ahead prices are commensurate to the contract prices from recent RPS contracts" is "revealed to be false by the 2018 RPS Padilla Report to the Legislature..." (*Id*. at 21.)

Similar to Winding Creek, Green Power advocates for ReMAT reform (*Id.* at 4-15) and states that PURPA requires the Commission to "encourage" renewable energy projects by offering avoided cost pricing. (Green Power Opening Comments at 2.) It argues that PURPA has "floor requirements" for avoided costs and that an avoided cost forecast cannot be based on an average of historic prices. (*Id.* at 1 (regulatory floor), 6 (floor requirements), & 20 (historical averages … not a forecast).) Green Power proposes that the Commission adopt a PURPA-compliant SOC and revise ReMAT to address the errors identified in the *Winding Creek Order*. (Green Power Opening Comments at 2.)

Regarding avoided costs, Green Power argues that, at a minimum, the Commission should consider locational net benefits "since that methodology is designed to capture the value of [distributed energy resources] at different locations on the grid." (*Id.* at 3 & 17-18.) Green Power also suggests that any avoided cost methodology "must also include a carbon cost because the proposed day-ahead three-year price average is for all power types, carbon-emitting and noncarbon-emitting" because "California utilities arguably must now buy only carbon-free power…" (*Id.* at 3.) Green Power objects to a 12-year contract term as too short to encourage investment in renewable energy, and it finds the Joint Parties' proposal for a maximum 3 year term to be even more unacceptable. (*Id.* at 3 & 16-17.) It proposes that, for simplicity, the Commission "adopt a single c/kWh price for each applicable contract type." (*Id.* at 3 & 20.)[12]

CASMU requests that the CASMU utilities should be exempted from this proceeding, or addressed in a later, separate track for a variety of reasons. Among other things, they explain that the CASMU utilities are significantly smaller than the larger Investor Owned Utilities that are the focus of this proceeding; CASMU utilities have significantly fewer QFs in their respective service territories and have accordingly implemented different policies and

[12] Many of these same Green Power arguments are provided in its September 12, 2018 comments on the OIR.

procedures to address PURPA; CASMU utilities were not parties to the QF Settlement and therefore do not use the QF Settlement SOC; and a one-size-fits-all approach should be avoided to ensure that unique characteristics of different utilities are recognized, particularly given the CASMU utilities' limited number of California customers and the disproportionate cost impacts that may result if they are required to participate in this proceeding.

4. Discussion and Analysis – PURPA's Requirements

4.1. The Commission Has Proactively Implemented PURPA For Nearly 40 Years

As described in the OIR, the Commission has a long history of embracing PURPA implementation over nearly four decades, resulting in more than 4,000 MWs of QF power in operation. (OIR at 2.)[13] Many of the state's first investments in renewable generation and efficient natural gas cogeneration stem from the Commission's implementation of PURPA. More recently, many of the product-specific procurement programs– such as ReMAT and the high efficiency CHP program – have been made possible because of the CPUC's proactive efforts to expand its ability to implement PURPA. For example, as long ago as 1992, the Commission required the Investor Owned Utilities to procure resources from QFs based on resource-specific competitive bids through the Biennial Resource Plan Update or "BRPU." (*So. Cal. Edison Co., et al.*, 70 FERC ¶ 61,215 at *61667 (1995).) The BRPU was a resource-specific PURPA program.

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[13] *See* Commission Decision (D.) 02-08-071 at 26-28 for an overview of PURPA-related requirements.

In 1995, in response to utility protests against the BRPU because it set different avoided costs based on specific types of generation – such as the cost of solar generation being used to set the avoided cost for solar QFs - FERC found that the Commission had violated PURPA because avoided costs must consider *all* generation sources, not just specific types of generation. (*So. Cal. Edison Co., et al.*, 70 FERC ¶ 61,215 at *61677 (1995).) In other words, while PURPA purportedly encouraged QF generation, FERC ruled that calculations of avoided costs had to include consideration of *all sources,* including larger fossil-fired generating units that had significantly lower costs at the time. (*Id.*) This FERC determination upended a process that had consumed many years of Commission and stakeholder efforts to require the Investor Owned Utilities to procure QF power at avoided costs for specific types of generation, many of which were renewables. (*See, e.g. So. Cal. Edison Co., et al.*, 70 FERC ¶ 61,215 at *61668 (1995).)

Recognizing that FERC's 1995 determination in *So. Cal. Edison* had the potential to interfere with the Commission's efforts in 2010 to support QF generation – including both more efficient CHPs and small renewables - the Commission petitioned FERC for a Declaratory Order that the Commission's decisions promoting CHP systems of 20 MW or less were not preempted by the Federal Power Act, PURPA or FERC regulations. (CPUC Petition for Declaratory Order, FERC Docket No. EL10-64-000, May 4, 2010.) When FERC's Order granting the Petition was not clear,[14] the Commission returned to FERC and

[14] *Cal. Pub. Utils. Comm'n,* 132 FERC ¶ 61,047 (July 15, 2010)

asked it specifically to confirm that the state enjoyed sufficient flexibility in calculating avoided cost rates to promote the development of highly efficient CHP generation that was considered necessary to achieve environmental goals, including compliance with federal and state air emission standards. (CPUC Request for Clarification, FERC Docket No. EL10-64-000, August 16, 2010.) In response, FERC affirmed that "the concept of a multi-tiered avoided cost rate structure to encourage different types of generation is consistent with the avoided cost requirements set forth in section 210 of PURPA and in the Commission's regulations." *(Cal. Pub. Utils. Comm'n,* 133 FERC ¶ 61,059, P 20 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011) (hereafter "*CPUC*".) This holding was entirely permissive: "a state *may* determine that capacity is being avoided, and so *may* rely on the cost of such avoided capacity to determine the avoided cost rate;" "just as a state *may* take into account the cost of the next marginal unit of generation, so as well the state *may* take into account obligations imposed by that state;" and "the CPUC *may* take into account actual procurement requirements, and resulting costs, imposed on utilities in California." (*Id.,* P 26 (*emphases added*).) FERC also reconsidered and overruled *So. Cal. Edison* to the extent it was inconsistent with these determinations. (*Id.,* PP 27, 28, & 30.)

This change in FERC precedent – achieved through this Commission's proactive efforts – means that this Commission has the option to adopt programs that set avoided cost for renewable generation with specific power production attributes, rather than requiring such resources to compete with larger, fossil-fired facilities. However, FERC expressly held that the Commission is not required to make all of its PURPA programs resource-specific, and it exercises its discretion here to adopt a New Standard Offer Contract that will be available to all QFs, regardless of size or technology.

4.2. PURPA Has Assisted in Meeting California's Aggressive Renewables Portfolio Standard

Comprehensive state laws require California utilities to meet some of the most aggressive renewable energy goals in the country. This requirement is referred to as the Renewables Portfolio Standard or "RPS." California's RPS was initially enacted in 2002; Senate Bill 1078 required 20% of electricity retail sales to be served by eligible renewable resources[15] by 2017. With the program's success, the legislature has incrementally accelerated and increased the RPS requirement. In 2006 Senate Bill 107 required 20% of electricity retail sales to be served by eligible renewable resources by 2010. In 2011, Senate Bill X1-2 expanded the RPS to require both retail sellers and publicly owned utilities to procure 20% eligible renewable resources by the end of 2013, 25% by the end of 2016, and 33% by the end of 2020. Current law requires utilities to meet an RPS of 50 percent by the end of 2026, and 60 percent by the end of 2030. (Cal. Pub. Utils. Code §§ 399.11(a), 399.15, and 399.30.) The Commission's 2019 California Renewables Portfolio Standard Annual Report explains that the Investor Owned Utilities have executed renewable electricity contracts necessary to meet the 33% RPS requirement by 2020 *and forecast reaching 50% by 2021* – well in advance of the 2026 requirement.[16] The Commission's embrace of PURPA at its inception, which

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[15] Significantly, eligible renewable resources for the purpose of RPS do not include large hydropower generation, which are not RPS-eligible resources, even though they are carbon-free. *See, e.g.*, Cal. Pub. Utils. Code §§ 399.12 and 399.30.

[16] *See* Table 2 on page 6 of the 2019 RPS Annual Report.

contributed to the development of renewable technologies, and its continued implementation of PURPA today has played an important role in this achievement.

4.3. The Commission Has Broad Authority and Flexibility When Setting Avoided Costs Under PURPA

PURPA encompasses a dual federal and state regime whereby FERC is required to issue regulations regarding how PURPA will be implemented, and states are required to oversee regulated utilities' procurement of QF generation consistent with the FERC's regulations

PURPA and FERC regulations implementing PURPA provide that QFs shall be paid "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." (16 U.S.C. § 824a-3(b) & (d); *see also Independent Energy Producers Ass'n v. FERC,* 36 F.3d 848 (9th Cir. 1994) (hereafter "*IEP*").) FERC refers to such prices as the utility's "avoided cost." (18 C.F.R. § 292.101(b)(6).) States are charged with calculating avoided costs based on factors set forth in FERC's regulations at 18 C.F.R. § 292.304(e).

The law is clear that state regulators have a great deal of discretion in determining avoided costs under PURPA. As the Ninth Circuit Court of Appeals recognized in *IEP*, the Commission has broad authority to implement Section 210 of PURPA, as "states play the primary role in calculating avoided costs," and states have "a great deal of flexibility … in the manner in which avoided costs are estimated …." *IEP* at 856. Such deference is appropriate with respect to ratemaking because ratemaking is a legislative, not judicial, function, "a task of striking a balance and reaching a judgment on factors beset with doubts and difficulties, uncertainty and speculation." *U.S. v. Morgan*, 313 U.S. 409, 417 (1941).

In 2010, FERC affirmed and further clarified these principles in *Cal. Pub. Utils. Comm'n,* discussed above. There, it emphasized the fact-specific nature of avoided cost determinations and its reluctance to "second guess" state determinations:

> As the Commission has previously explained, "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA…." [*See American REF-FUEL Company of Hempstead*, 47 FERC ¶ 61,161, at 61,533 (1989); *Signal Shasta*, 41 FERC ¶ 61,120 at 61,295; *see also LG&E Westmoreland Hopewell*, 62 FERC ¶ 61,098, at 61,712 (1993).] In this regard, the determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include consideration of many factors, and we are reluctant to second guess the state commission's determinations; our regulations thus, provide state commissions with guidelines on factors to be taken into account, "to the extent practicable," [18 C.F.R. § 292.304(e) (2010)] in determining a utility's avoided cost of acquiring the next unit of generation.

(*CPUC* P 24.)

Indeed, FERC recognized when it first adopted its PURPA regulations that no single method for estimating avoided costs would meet the needs of every state. Thus, it made clear that states were generally free to use whatever avoided cost determination methodology they felt met the needs of their state. FERC's 1988 *Administrative Determination* explained FERC's reasoning behind the 1980 adoption of its PURPA regulations:

> A staff paper that preceded the Commission's regulations concluded that:
>
> **[the] variety of arrangements that might be made between qualifying facilities and utilities is enormous.** Therefore, we would recommend that the Commission promulgate broad general rules in the nature of guidelines, leaving flexibility for the states to experiment and accommodate local circumstances and leaving room for the parties to negotiate the particular terms and conditions of their arrangement within the broad parameters of the Commission's rules.[17]
>
> The philosophy behind this recommendation was that **state regulatory authorities, utilities, and QFs, being closer to each transaction, were better situated than the Commission to judge the actual costs avoided.** The Commission accepted this recommendation and accordingly issued generic rules that focused on the theory of avoided cost rather than the details of its determination. **Thus, state utility commissions were generally free to use whatever avoided cost determination method they felt met the needs of their state.**
>
> The Commission found that:
>
> > [to] the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogenerators and small power producers, it will be considered as satisfactorily

[17] Quotation from "Staff Paper Discussing Commission Responsibilities to Establish Rules Regarding Rates and Exemptions for Qualifying Cogeneration and Small Power Production Facilities Pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978," Docket No. RM79-55, at 26.

implementing the Commission's rules.[18]

Administrative Determination of Full Avoided costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, IV Federal Energy Reg. Comm'n Rep. (CCH) Par. 32,457 (Mar. 16, 1988), 2015 WL 8610994, at 11 (emphases added) (*Administrative Determination*).)

FERC has also been clear that setting avoided cost rates does not require mathematical precision or an exact correlation with actual costs. *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed. Reg. 12,214, at 12,224 (1980) (*Rulemaking Order*).

In sum, FERC's regulations do not mandate using a particular methodology or factors that must be addressed when setting avoided cost rates. Instead, the regulations list *factors to be considered* by a state commission, "to the extent practicable," such as the availability of electricity during daily and seasonal demand peak periods, and the reliability of the facility. (*See,* 18 C.F.R. §§ 292.304(b)(2), (e); *CPUC,* 133 FERC ¶ 61,059, at 24.)

4.4. The Commission's Challenge in Identifying An Appropriate Methodology To Set Fixed-Price Avoided Costs For Long Term Contracts

PURPA and FERC's implementing regulations provide that a QF shall be paid *no more than* the utility's avoided cost, shall be just and reasonable and in the public interest, and shall not discriminate against QFs. (16 U.S.C. § 824a-3(b) & (c); 18 C.F.R. § 292.304(a)(1) & (2).) In addition, FERC's regulations require

[18] Quotation from 45 FR 12226, *FERC Statutes and Regulations, Regulations Preambles 1977-1981* ¶ 30,128, at 30,883.

state regulators to establish avoided cost rates for both energy and capacity that are known at the time the contract is executed. (18 C.F.R. § 292-304(d)(2).)[19]

The Commission has previously faced numerous challenges in setting such rates,[20] which often involved reliance on long term forecasts of fossil fuel prices, and the utility's cost to construct a combined cycle gas turbine (CCGT), which was assumed to be the next "hypothetical unit" that a utility would build but for the QF's generation. (*Administrative Determination* at 2015 WL 8610994, at 7). These forecasted rates are often referred to as "administrative determinations" of avoided cost.

Developing this type of administratively determined forecast of avoided cost is even more difficult today because of the changes that have occurred in California's energy markets. Those changes have led to a reduced availability of the type of specific information regarding the cost to construct and operate a generation facility that were previously used in administrative determinations of avoided cost. This is because regulated utilities in California no longer own and operate the vast majority of California's generation, so that this information is not readily available from them.

In addition, California's generation mix has changed substantially as a result of the RPS so that reliance on the costs to build and/or operate a CCGT

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[19] Energy costs are the costs associated with the incremental production of electric energy, including the cost of fuel and certain operation and maintenance costs. (*IEP* at 851, fn. 5 citing FERC's 1988 *Administrative Determination* at 32,157). Capacity costs are the costs associated with providing the capabilities to meet the demand for electric energy. (*Id.)*

[20] *See, e.g., IEP* at 852 (describing CPUC efforts to project future avoided costs based on fossil fuel prices).

would not reflect the utilities' avoided costs today. For example, 26%[21] of the generation in the CAISO in 2018 was non-hydro renewable generation,[22] whereas in 2013 non-hydro renewable generation accounted for only 13% of the generation mix.[23] Indeed, natural gas dominated the generation mix in 2013, accounting for 40% of supply while in 2018 it accounted for 30% of CAISO supply.[24]

In light of these market changes and the absence of cost data on new IOU-owned generation in California, the Commission looks to the prices for energy reflected in the CAISO markets and the prices for capacity reflected in the bilateral contract market for Resource Adequacy (RA) for actual and accurate prices the utilities pay for the next increment of energy and capacity. These markets provide accurate, comprehensive, and publicly available information regarding the incremental cost of generation, which is more likely to produce more accurate avoided cost forecasts than prior methodologies. Among other things, these market prices reflect the price paid to all generation sources at a specific location, including multiple types of renewable generation as well as gas-fired facilities.

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[21] CAISO's 2018 Annual Report on Market Issues & Performance, May 2019, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

[22] CAISO's 2018 Annual Report on Market Issues & Performance, May 2019, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

[23] CAISO's 2013 Annual Report on Market Issues & Performance, April 2014, available at http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[24] CAISO's 2018 Annual Report on Market Issues & Performance, May 2019, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

We note that the prices that load-serving entities pay in contracts for RPS-eligible energy are not publicly available until three years after deliveries begin. Prior to this, RPS contract prices are available to the Commission only confidentially, but are not available to the public or to market participants. (General Order 66-D; D.06-06-066). Prices in RPS contracts executed by community choice aggregators (CCAs) and energy service providers (ESPs) are likewise not public. (D.19-12-042.) Thus, looking to such contracts to inform the determination of avoided cost would lack transparency and conflict with our policy preference of allowing parties to review the pricing methodology.

Significant for PURPA compliance, the information generated by the CAISO markets also allows state regulators to accurately address far more of the factors listed in FERC's regulations than prior avoided cost models. For example, 18 C.F.R. § 292.304(e)(2) provides that "the following factors shall, to the extent practicable, be taken into account:"

> The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
>
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities…

Many of these factors could not have been accurately valued under the methodologies used to set avoided cost rates in the early years of PURPA. In contrast, many of these factors are reflected in today's market price information. For example, location-based pricing (such a LMPs) and application of NQC address the primary goal of considering the availability of QF capacity or energy during system daily and seasonal peak periods. Energy prices from the CAISO market also reflect the utility's ability to dispatch the QF ((e)(2)(i)), the reliability of the QF ((e)(2)(ii)); and the individual and aggregate value of energy and capacity from QF's on the utility's system ((e)(2)(vi)). Factors such as the duration of the obligation ((e)(2)(iii) and coordination of scheduled outages ((e)(2)(iv) relate to capacity obligations and are reflected in the RA contract prices relied on here, which include an obligation to perform and coordination of scheduled outages.

Given California's current mix of resources, and the trend toward increasing renewable generation supply, it is appropriate for the Commission to rely on energy market prices that reflect the broad array of resources selling into the market – including fossil fuel facilities, CHPs, and renewable facilities – to identify avoided costs. As such, we find reliance on CAISO market prices appropriate for both QFs seeking a price fixed at the time of contract execution, and for QFs electing to be paid based upon avoided cost at the time of delivery.

In addition, in order to ensure consistency among the data sets, and a consistency of methodology, we find that averaged prices used to establish the rates should include five years of data, rather than the three years of data variously proposed in the Staff and Joint Proposals. Where rates based on averages of costs are adopted here – whether looking back for energy or forward for capacity - we find that a five year average is more likely to accurately reflect variations in energy prices over time by incorporating more data into the pricing mechanism. Among other things, using five years of data rather than three, each year is given less weight in the formula, muting the potential effects of anomalous years (whether high or low). This is particularly important given that prior and continuing impacts of climate change on the state's hydrology and weather patterns can cause significant variation in annual electricity prices. In addition, using a five-year average – which we propose for all averaged prices in the New QF SOC – provides methodological uniformity. While we recognize that in some circumstances, more data is better, we find that using market price data for energy more than five years back would not reflect the significant change in California's generation profile, described above, which has occurred more recently, and will continue over time. We find that rolling averages based on five years of data and updated annually for new contracts will appropriately take changes in energy and capacity prices into account.

Finally, for all of the reasons set forth above, we do not adopt the Winding Creek and Green Power proposals to set avoided costs based on "computerized forecasting models." (Winding Creek August 31, 2018 Comments at 5-6 and Opening Comments at 6; Green Power Opening Comments at 20-21.) Neither party expressly identifies what such forecasting models would consider; instead they simply claim that the Staff and Joint Proposals violate PURPA because a forecast cannot be based on historic market prices. (*Id.*)

As described above, FERC has been clear that state regulators have significant discretion in setting avoided costs, and FERC expressly declined to identify specific methodologies to set avoided costs in deference to state needs. As described in more detail below, the historic information of actual costs that we propose to rely on takes into account many of the factors PURPA identifies for consideration in establishing avoided costs. Consequently, we find that our adopted methodologies using actual prices accurately forecasts future prices for energy and capacity. We reject the use of administratively determined forecasts that require estimates of many unknown and unknowable variables because it could result in prices significantly higher or lower than actual avoided costs. *See, e.g., IEP*, 36 F.3d at 852 (reflecting the Commission's unsuccessful attempts to set avoided cost rates based on forecast oil and gas prices).

4.5. Response to Other Claims That The Staff Proposal Violates PURPA

In addition to the claims described above, Winding Creek and Green Power repeatedly argue that the Commission's implementation of PURPA in this proceeding is unlawful and discriminatory, because the Staff Proposal does not "encourage" QF generation. (Winding Creek August 31, 2018 Comments at 7;

Opening Comments at 4; Green Power September 12, 2018 Comments at 2, 4, 9, 11; Opening Comments at 2, 3, and 18.) Winding Creek states that the Commission seeks to "eviscerate" PURPA and "kill" QF contracts. (Winding Creek August 31, 2018 Comments at 3.) These claims are mistaken.

While PURPA intends for states to "encourage" QF development, it also requires states to balance this goal with the need to ensure just and reasonable rates in the public interest. 16 U.S.C. § 824a-3(b)(1); *Exelon Wind 1 L.L.C. v. Smitherman,* 766 F.3d 380, 384 (5th Cir. 2014). Specifically, as explained above, PURPA and its implementing regulations require that rates shall not exceed the utility's avoided cost: the incremental cost to the utility of the electricity that, but for the purchase from the QF, the utility would need to generate or purchase from "another source." *See* 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. §§ 292.101(b)(6), 292.304(a)(2).

PURPA was never intended to guarantee QFs a rate of return or to be a subsidy. (*See* H.R. Conf. Rep. at *7831-32 (Oct.10, 1978).) As FERC has observed, rates exceeding avoided cost also allow QFs an unfair advantage in the competitive wholesale markets. (*So. Cal. Edison Co.,* P 61,175-76, *overruled on other grounds by CPUC* PP 26-30.)

Green Power's claim that the Staff Proposal's proposed energy pricing is not consistent with recently executed long-term prices for energy (Staff Proposal at 5) is also misplaced. (Green Power Opening Comments at 21.) Presumably, Green Power believes that the recent RPS prices in the 2018 Padilla Report to the Legislature ("Padilla Report") are higher than the energy price proposed in the

Staff Report.[25] Assuming this is the case, it appears that Green Power mistakes the averaged price of an RPS contract shown in Figure 4 of the Padilla Report, which includes both energy and capacity, with the proposed price of energy in the Staff Proposal. It is not accurate to compare the Staff Proposal for determining energy prices alone to RPS contract prices that include compensation for both energy and capacity.

Green Power's claims that the adopted avoided costs must include a carbon cost and take into account locational benefits (Green Power Opening Comments at 3 & 17) are mistaken. FERC has found that compensation for environmental externalities (like a carbon cost) is *outside of PURPA and not a part of the avoided cost calculation.* (*American Ref-Fuel,* 105 FERC ¶ 61,004 at 23.) This comports with the fact that gas-fired power plants that sell electricity in the CAISO market are already required to pay a "carbon price" pursuant to the cap and trade program implemented by the California Air Resources Board (CARB).[26] Renewable facilities that sell electricity in the CAISO market do not incur such costs. Regarding locational benefits, both the avoided cost pricing in the Staff Proposal and the pricing adopted in this Decision, based on LMPs, varies by location and therefore takes local grid benefits into account.

Arguments by Winding Creek and Green Power that the Commission should revise the ReMAT program are outside of the scope of this proceeding.

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[25] The 2018 Padilla Report to the Legislature is not in the record of this proceeding, but is publicly available on the Commission's website at https://www.cpuc.ca.gov/General.aspx?id=6442457306

[26] *See* Title 17 CCR §§ 95811, 95812, & 95852.

(Winding Creek August 31, 2018 Comments at 5; Green Power November 14, 2018 Comments at 2). The objective of this OIR was to provide for a New QF SOC available to all QFs that expressly contains all of the pricing provisions set forth in 18 C.F.R. § 292.304(d). The questions to be addressed were clearly set forth in both the OIR and in the Scoping Memo. (*See* OIR at 8-9 and Scoping Memo at 3-4.) Those questions asked what the appropriate avoided cost would be for each category of energy and capacity being provided by a QF. Revisions to ReMAT, to the extent necessary, is a subject to be addressed in other Commission proceedings.

Finally, certain other claims - that the pricing proposals considered in this proceeding are not PURPA-compliant because they are inconsistent with other pricing proposals in other Commission proceedings - are inapposite. (Winding Creek August 31, 2018 Comments at 5.) Avoided cost rates do not have to be "one size fits all."

To ensure that the prices adopted here reflect the market as closely as possible, they reflect, where practicable, the resource adequacy value, the location of the generation, and the time of day that the generation is produced. (*See* 18 C.F.R. §292.304(e).)

For all these reasons, and more as set forth throughout this Decision, Winding Creek and Green Power's various claims that the Staff Proposal would violate PURPA have no merit.

5. Discussion and Analysis Regarding Avoided Cost Prices

The following discussion and analysis address the avoided cost pricing issues identified in the OIR and restated in Section 2 above. In adopting these avoided cost pricing mechanisms for QFs, we note that conditions may change, and the Commission may revisit the avoided cost pricing mechanisms for QFs in the future as appropriate.

5.1. Energy Price at Time of Contract Execution

5.1.1. Determination

For the energy price identified at the time of contract execution (18 C.F.R. § 292.304(d)(2)(ii)), we adopt (with modifications) the Joint Parties' proposal to use a multi-year average of publicly available CAISO LMPs, calculated on a monthly basis with periods based on the Commission's most recently approved standard time-of-use (TOU) periods specific to a utility, and a collar based on prices at the relevant Energy Trading Hub in which the facility is located (either North of Path 15 or South of Path 15). These prices will remain the same for the term of an executed contract, but will be updated annually for new standard offer contracts to reflect changes in market conditions.

Each Investor Owned Utility shall file a Tier 2 advice letter within 30 days of the issuance of this order containing a working Excel file with columns containing the following information:

- All Aggregated Pricing Nodes ("APNodes") in its service area;
- The five-year historical average of LMPs for each APNode based on the 60 months from January 2015 through

December 2019, calculated on a monthly basis for each TOU period as defined above;

- The five-year historical average of the applicable Energy Trading Hub prices (NP 15 or SP 15), calculated in the same manner as the LMPs;
- The potential +/- 10% collar applicable to each APNode based on the five-year historical average of the applicable Energy Trading Hub prices, calculated on a monthly basis for each TOU period; and
- The resulting energy prices available to QFs at each APNode by month and TOU period.

The advice letter shall also explain how a QF can identify its APNode. The information provided shall be presented in the format demonstrated in the Appendix attached hereto.[27]

On the first business day of March each year, the Investor Owned Utilities shall make available new prices for new contracts by updating these calculations through the Tier 1 advice letter process, using historical prices during the 60 month period for the five prior January-to-December years. The Investor Owned Utilities shall also ensure that this information is posted publicly on their respective websites. In that annual filing, if the Investor Owned Utilities determine that Time-of-Day Periods should be revised due to future market conditions, or their TOU periods are updated, they may file a Tier 2 advice letter proposing new hours and justifying the proposal's rationale.

[27] In the event of an irreconcilable difference between the requirements in this Decision and the attached Appendix, this Decision shall control.

5.1.2. Rationale

For the energy at time of contract execution price option, Staff proposed to use an average of publicly available CAISO DLAP prices over the past three years, allocated to TOU periods as set forth in Tables 12-14 of the Staff Proposal. (Staff Proposal at 21-23.)[28]

The Joint Parties adopted the basic principles of the Staff Proposal – proposing a three-year average of publicly available CAISO prices allocated to TOU periods. However, the Joint Parties proposed using a three-year average of the CAISO's LMPs at the generator's APNode, allocated by month across three different Time-of-Day periods – Shoulder Peak, Mid-day Peak, and Off Peak. (Joint Proposal at 4-5.) The Joint Proposal results in 36 prices across the year, 3 for each Time-of-Day period in each month of a calendar year. (*Id*. at 5-6.[29]) The Joint Parties also proposed a "collar" around those LMP prices to ensure the LMP prices do not vary significantly from averaged market energy prices – either up or down. (*Id*. at 4-5.)

The Joint Proposal laid out the methodology and basis for this LMP approach in some detail:

> Since the Joint Parties are trying to establish a price based on the procurement cost for generation (PNode), and not the aggregated price paid by load (DLAP), the …. Joint Parties [sic] proposal more accurately reflects the utility's avoided cost. However, to limit the bounds in PNode pricing

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[28] Note that the text of the Staff Proposal sometimes refers to the wrong table. The table numbers referred to here are the numbers actually assigned to the tables in the Staff Proposal.

[29] *See* Joint Proposal at 6: "The three separate time periods per month results in 36 separate pricing periods per calendar year."

> variability, the PNode price will be subject to a collar equal to the Energy Trading Hub price for the same hours plus or minus 10%.
>
> Here is an example of how the collar on the PNode price will function. Assume a three-year historical average of PNode price for a time period is $29/MWh, and the three-year historical average for the applicable Energy Trading Hub Price for the same time period is $30/MWh. To calculate the collar around the PNode price, we take +/-10% of the Energy Trading Hub Price, which results in a minimum price floor at $27/MWh and a maximum price cap at $33/MWh. Since the $29/MWh PNode price with [sic] within the Trading Hub collar, the PNode price is the fixed-price payment for that time period. However, if the PNode price for that time period was $25/MWh, the Trading Hub cap would apply, and the fixed price would be set at $27/MWh for that time period. Likewise, if the PNode price was $35/MWh for that time period, the Trading Hub cap would also apply, and the fixed price would we set at $33/MWh for that time period. (Joint Proposal at 4-5.)

TURN observed that the proposal to set the rate using the LMP based on the generator's own node instead of the DLAP price was "most consistent with PURPA, because the purchasing utility would still incur losses and congestion charges when the generator's power is delivered to a utility's load. The pricing of deliveries at a utility's DLAP might 'double count' losses and congestion costs, as the DLAP already reflects aggregated losses and congestion charges."[30]

We concur with the Joint Proposal's preference for LMP prices, which is supported by TURN's observation. We note that LMP pricing is appropriate

[30] Comments of The Utility Reform Network on Staff Pricing Proposal and Rulemaking R.) 18-07-017, at 2.

given the maturity of that market and the number of PURPA-compliant factors that it reflects. As the CAISO's Business Practices Manual explains, LMP "is the marginal cost (expressed in $/MWh) of serving the next increment of Demand at that PNode consistent with transmission facility constraints, transmission losses, and the performance characteristics of the resources,"[31] and more specifically the LMPs at an APNode, "are calculated after Market Clearing as the weighted average of the LMPs at their individual PNodes, using distribution factors as the weighting factors."[32] As a result, the "LMPs for Energy [] reflect the System Marginal Energy Cost (SMEC), Marginal Cost of Losses (MCL), and Marginal Cost of Congestion (MCC)."[33] We also find that using LMP prices is appropriate because they are publicly available.

More specifically, the CAISO network is composed of Nodes, a subset of which CAISO selects to act as Pricing Locations (PNodes). Each generator is mapped to a PNode. Aggegated Pricing Nodes (APNodes) are groupings of PNodes used to consolidate bidding and pricing of supply and demand in the CAISO Markets.[34] The hourly price determined for the PNode is paid to all generating facilities at that location, including both renewable and fossil-fuel generating facilities.

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[31] California ISO, *Business Practice Manual for Market Operations, version 61*, revised August 7, 2019, at 128.

[32] *Ibid.*

[33] *Ibid.*

[34] All but one APNode have multiple generators feeding into that APNode so that the averaged price generated at any APNode is the avoided cost for the utility to serve load in the APNode area.

In the Ninth Circuit's recent decision *Californians for Renewable Energy v. CPUC*, 922 F.3d 929, 937 (9th Cir. 2019), the Court held that, "where a utility uses energy from a QF to meet a state RPS [Renewables Portfolio Standard], the avoided cost must be based on the sources that the utility could rely upon to meet the RPS." As discussed in Section 4, state law requires 33% of total retail sales of electricity in California to be from eligible renewable resources by the end of 2020, 50% by the end of 2026, and 60% by the end of 2030.

To bring the CPUC into full compliance with PURPA as soon as possible, it is appropriate to look beyond only RPS generation to determine the avoided cost price of RPS-eligible QF resources at this time. That is because pursuant to the CPUC's 2019 Renewables Portfolio Standard Annual Report, PG&E, SCE, and SDG&E have already signed procurement contracts that satisfy their existing RPS obligations and will satisfy their RPS obligations for many years into the future.[35]

The RPS Procurement Plans approved by the Commission in December 2019 indicate that the large IOUs will not hold any solicitations to meet RPS obligations.[36] The large IOUs have not held solicitations to meet RPS obligations since 2014 for SDGE, 2015 for PG&E and 2016 for SCE.[37] PG&E will not need to

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[35] *See* Table 2 at 6, showing IOU RPS compliance surpassing 50% by 2026 requirement and forecasted to reach 51% eligible renewable resources by 2021.

[36] *See* D.19-12-042 issued Dec. 30, 2019, *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program*, at 4, describing that the CPUC is granting the requests of the IOUs to forgo holding a RPS solicitation in 2019 because the IOUs already have sufficient renewable energy generation in their portfolios to meet the requirements of the RPS statute.

[37] D.19-12-042 at 10 "2019 marks the fifth year in a row that PG&E and SDG&E will forgo an annual RPS solicitation; it is the fourth year in a row for SCE." *See also* D.14-11-042 at 128 and D.15-12-025 at 10-11, & 34.

procure additional RPS resources until 2029, but when considering its "Bank" [defined as renewable procurement greater than what is needed for RPS compliance in a given compliance period] this is extended even further, until 2033.[38] SCE anticipates it can use its Bank to meet its RPS obligations until 2030 and beyond.[39] SDG&E anticipates using its Bank to meet its RPS obligations through 2033.[40] In addition, the Commission approval of 2019 IOU RPS Procurement Plans authorizes PG&E, SCE and SDG&E to sell Renewable Energy Credits (RECs) generated from their renewable electricity procurement because they expect to have excess RECs beyond what is needed for their RPS obligations in the 2021 – 2024 compliance period.[41] PG&E, SCE and SDG&E were also authorized to sell RECs due to procurement in excess of RPS obligations in the 2018 RPS Procurement Plan decision.[42]

Unlike other renewable energy procurement in California, electricity generated under any contract currently executed pursuant to PURPA does not create RECs that may be used to meet the RPS.[43] Moreover, in *American Ref-Fuel Co. et al.,* FERC determined that PURPA contracts between a QF and a utility generally do not automatically convey RECs to the purchasing utility unless

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[38] D.19-12-042, at 17; *see* Decision (D.) 17-06-026 Section 3.1.5 for a detailed discussion on excess procurement of RECs which can be applied in later compliance periods.

[39] D.19-12-042, at 25.

[40] D.19-12-042, at33.

[41] D.19-12-042, at 68, 83, & 87.

[42] D.19-02-007, at 114-116, Ordering Paragraphs 8-10.

[43] Public Utilities Code Section 399.21(a)(5).

expressly stated in the purchase contract.[44] Instead, while a state may decide that the sale of renewable generation at wholesale automatically transfers ownership of the state-created REC, that requirement must find its authority in state law.[45] California has decided not to create RECs from renewable energy QFs. Indeed, California law prohibits the creation of RECs for any electricity purchase contract executed after January 1, 2005.[46] Instead, PURPA contract procurement is tracked by the California Energy Commission for the purpose of counting toward the RPS requirements of the purchaser.[47]

It is possible, but not required, that an IOU will use energy procured using the New QF SOC to meet its RPS obligations. The Energy Commission would track the IOU's procurement and a REC with compliance value would not be generated. It is appropriate to look beyond only RPS-eligible generation to determine the avoided cost price of RPS-eligible resources at this time because the RPS program is complied with, no new procurement is currently necessary to meet the statutory RPS goals, and no REC of compliance value is generated by a PURPA contract. The avoided cost pricing methodology for energy adopted in this decision uses an average of the hourly LMP price – which is one price paid to all generation sources at a specific location, whether renewable or fossil-fuel. This decision properly calculates the incremental cost to an IOU of alternative electric energy considering all sources, not measured against only the sources

[44] 105 FERC P 61,004, at 18 (Oct. 1, 2003).

[45] 105 FERC at 3 & 24.

[46] Pub. Utl. Code § 399.21(a)(5).

[47] Pub. Utl. Code § 399.21(a)(5).

required to meet already complied with state law as that would not reflect an IOUs current avoided cost.

We further find that averaging the historic CAISO LMPs to forecast fix energy prices for long-term contracts, is appropriate. As the Staff Proposal noted:

> … CAISO prices have remained fairly stable over the past three years and have not exhibited a clear upward or downward trend. In addition, these prices appear to be consistent with long-term contracts that have been executed recently for renewable energy. Finally, from a more macro perspective, there are pricing pressures that apply in both directions – that is, increasing penetration of renewables could exert downward pressure on prices (as they have done during mid-day periods over the past several years) and fluctuations in gas prices and supply and demand balances could exert either upward or downward pressure on prices over the coming decade.

(Staff Proposal at 23.) The Joint Parties concur, stating:

> Winding Creek incorrectly states that 18 C.F.R. § 292.304(d)(2)(ii) "requires a forward-looking forecast. Looking backwards 3 years is not a forecast of *future* avoided costs [,]".... Contrary to Winding Creek's assertion, 18 C.F.R. § 292.304(e) sets forth specific factors that should be taken into account, to the extent practicable, in determining utility avoided costs. Notably, PURPA's enumerated factors in determining avoided costs do not mandate a forward-looking forecast be utilized, or even suggest that such an approach is preferred over a historical approach.

(Joint Utility and QF Parties Reply Comments at 5, footnotes omitted, emphasis in original.)

The Joint Parties are correct that PURPA does not preclude a forecast of future avoided costs based on historic actual cost information. As described above, PURPA allows states the discretion to use whatever methodology meets their needs. (*Administrative Determination* at 2015 WL 8619004, at 11.)

We adopt a five-year average over the three-year average in the Staff and Joint Proposals for the reasons set forth above. We also adopt the "collar" proposal because it ensures that the LMP prices will not vary significantly from averaged market energy prices – either up or down – thereby more accurately reflecting the utilities' avoided costs. In adopting this avoided cost pricing methodology, the Commission has considered, to the extent practicable, each of the factors set forth in 18 C.F.R. § 292.304(e). We find that the avoided costs adopted here for energy at the time of contract execution are consistent with federal avoided cost regulations, including18 C.F.R. § 292.304(e) because, among other things: (1) they are consistent with other energy costs the Investor Owned Utilities have incurred over the last five years for both long-term and short-term energy; (2) the monthly averaging of prices and Time-of-Day periods take daily and seasonal peak periods into account; (3) the reliance on APNode pricing with a collar based on the Energy Trading Hub price takes into account both the individual and aggregate value of energy from the QFs on the utility's system; (4) the rates reflect a forecast of what the Investor Owned Utilities would otherwise pay for energy, since they would purchase energy from the same CAISO markets that inform the forecasts; and (5) the rates take into account the costs or savings resulting from variations in line losses.

Given the undisputed facts identified in the Staff Proposal – relatively stable prices, but with potential pressures in both directions (Staff Proposal at 23) – and the record before us, we have no basis to find that other suggested approaches would be more accurate.

5.2. Capacity Price at Time of Contract Execution

5.2.1. Determination

For the capacity price identified at the time of contract execution (18 C.F.R. § 292.304(d)(2)(ii)), we adopt the Staff Proposal to use an average of publicly available RA prices, shaped to time periods based on generation capacity allocation factors adopted by the Commission and applied to updated TOU periods. We add a 2.5% escalation factor for each year of the contract term after the last year included in the average. (Staff Proposal at 23-24.) To account for a facility's local, zonal or otherwise locational attributes, we deviate from the Staff Proposal and direct the use of the five-year weighted average RA contract prices that are published in the most current annual Resource Adequacy Report prepared by Energy Division. These five-year weighted averages include four unique weighted average RA capacity contract prices, including RA obligation type (local and system RA) and zone (North of Path 26, or NP-26, and South of Path 26, or SP-26). Those RA capacity prices shall then be shaped by applying the Commission's most recently approved capacity allocation factors, and TOU factors, (Staff Proposal at 18) pursuant to the following formula: $C_{ToE} = (C_{AF} / H)$ X RA where:

C_{ToE} = Capacity Price at Time of Execution, expressed in $/kWh.

C_{AF} = Capacity Allocation Factor, which allocates the capacity value for seasons and time-of-delivery periods.[48]

H = The number of delivery hours that comprise the applicable TOU period which was used to calculate the Capacity Allocation Factor.

RA = Capacity Price for a given RA obligation type and zone, derived from the most current annual Resource Adequacy Report prepared by Energy Division as described above.

The resulting number is the As-Delivered Capacity Price that a facility will be paid expressed in $/kWh for each period.

As with the energy prices described in Section 5.1 above, these capacity prices will remain the same for the term of an executed contract, but will be updated annually on the first business day of March for new standard offer contracts in order to reflect changes in RA market conditions and the most recently approved capacity allocation and TOU factors.

Each Investor Owned Utility shall identify the monthly capacity payments by zone (NP-26 or SF-26) and RA obligation type (local or system RA) in the Tier 2 Advice Letter served within 30 days of the issuance of this order. The payment to the QF shall be the Weighted Average Price for NP-26 or SP-26 and local or system RA, expressed in $/kW-month for Aggregated RA Capacity Contracts, shaped by the formula by applying the Commission's most recently

[48] Capacity allocation factors allocate the capacity value for seasons and time-of-delivery periods. These factors are derived by using the most recently adopted TOU periods and the most recently adopted capacity allocation factors, dividing the allocation percentages effective January 1, 2019, and approved in D.97-03-017 by the number of hours in each time-of-delivery period.

approved capacity allocation factors, and TOU factors, pursuant to the formula above and found in the Appendix attached hereto.

For example, if the Tier 2 Advice Letters submitted pursuant to adoption of this Decision are filed before the 2019 Resource Adequacy Report is published, the Investor Owned Utilities shall use the 2018 Resource Adequacy Report, which reports the Weighted Average Price of capacity by zone and RA obligation type in the fourth line of Table 7 "Aggregated RA Contract Prices, 2018-2022." The NP-26 price is $2.89/kW-month for local RA and $2.87/kW-month for system RA and the SP-26 price is $3.51/kW-month for local RA and $2.38/kW-month for system RA. These prices shall then be shaped as described above. A 2.5% escalator will be added to each year after 2022, the last year in the five-year aggregated RA contract price average.

With the release of the 2019 Resource Adequacy Report, the five- year aggregated RA contract price average will reflect the aggregated price of RA contracts for 2019 through 2023, and the 2.5% escalator will be added to each year after 2023. An example of this calculation is available in the Appendix. The Investor Owned Utilities shall update these capacity prices by Tier 1 advice letter annually on the first business day of March until all the contracts under the New QF SOC have terminated.

5.2.3. Rationale

The Staff Proposal identified two options for a fixed capacity price: (1) a price based on the as-available capacity prices currently available in the QF Settlement SOC with a pre-specified escalation factor of 2.5 percent, allocated by season and TOU or (2) a price established by "an average of publicly available RA prices at the time of execution." (Staff Proposal at 23-24.)

The Joint Proposal addresses the issue of capacity price, but without specifying whether the Joint Parties' position applies at time of execution, time of delivery, or both. It supports use of the prices reported and analyzed in the Energy Division's annual Resource Adequacy Report, which is publicly available on the Commission's website. However, the Joint Parties propose use of a three-year average of RA prices made available in that report – perhaps overlooking the fact that the averages in the report are based on an aggregate of five years of data.

The Joint Proposal explains:

> This report is an objective source of market information and represents the value of RA capacity in California. The use of a three-year average to set the fixed price is consistent with the use of three-year historical pricing to fix the energy price and is a reasonable approximation of the utility's value placed on RA Capacity given the lack of publicly available forward price information. (Joint Proposal at 6.)

The heading to this aspect of the Joint Proposal also clarifies that the price should be based on the "zone where the project is located." (*Id*.) The Joint Parties also propose that the net contract capacity for capacity payments be based on NQC, which is consistent with the rule that a load-serving entity's RA compliance is based on NQC. (*Id*.)

We find that using data from the RA program is an appropriate measure for calculating the utilities' avoided costs. The RA program was developed in response to the 2001 California energy crisis, and is designed to ensure that the

Commission jurisdictional load serving entities (LSEs) have sufficient capacity to meet their peak load with a 15 percent reserve margin. The program provides the energy market with sufficient forward capacity to meet peak demand and integrate renewables, including system RA, local RA, and flexible RA, all measured in megawatts. The RA program requires LSEs to make various and multiple compliance showings to ensure sufficient resources to meet peak load.

The prices for RA capacity produced by the RA program are an accurate reflection of the utilities' (and other LSEs') avoided costs for capacity. When the utilities procure capacity, they do so through these markets. We also find that the Energy Division's annual Resource Adequacy Report, which relies on five-year averages from prices in RA-only, bilateral contracts, is an accurate publicly available reflection of those avoided cost prices for capacity. In addition, we note that using such market-based prices to establish the avoided cost value of QF capacity is administratively efficient because such prices already incorporate locational, seasonal, and TOU differences, making additional price adjustments for such factors unnecessary.

We agree that a QF's capacity payments should be based on NQC, calculated as provided in the annual Resource Adequacy Report.[49] This is because, as the Joint Parties State, "[t]his reflects how the current market measures, values and trades capacity. Capacity only has value to the extent that it is accepted for compliance with a Load-Serving Entity's RA obligation." (Joint Proposal at 6.) However, we find that it would not be appropriate to adopt fixed

[49] The 2017 Resource Adequacy Report addresses the process for determining NQC in Chapter 5, at 43-47.

capacity prices based on a five-year forward average without an escalation factor for those years occurring after the term of the five-year average.

Given that no party has objected to the Staff Proposal of an annual 2.5% escalation factor added to capacity costs based on QF Settlement SOC prices, we find it reasonable to adopt this. Among other things, while the escalation factor has the possibility to overcompensate QFs because QF plant costs traditionally comprise the bulk of their costs and will not change significantly over time – the modest escalator is appropriate due to possible price increases in the capacity markets over time, as discussed below.

For similar reasons, while we recognize that using an average of five years of forward RA prices may overstate the value of QF capacity (particularly intermittent renewables), we find that the methodology is appropriate in light of possible changes in the capacity markets over time, as discussed below.

We recognize that California's capacity markets are in a state of flux, in part because significant amounts of utility load have migrated to other load serving entities, such as Community Choice Aggregators – thus creating multiple entities now competing for the same RA resources. Other factors include statutory obligations to retire older generation facilities and RPS requirements. We also recognize that recent RA compliance filings interpreted by a Staff report reflects that load serving entities have had increased difficulty procuring sufficient capacity to meet their RA requirements, with some load serving entities reporting an inability to identify available capacity "at any price." Considering all of this, the report concludes that "[a]lthough it appears that there is currently sufficient capacity on the system, and compliance with RA requirements is possible, we can expect that the market will continue to tighten." This is because replacements are not keeping up with retirements.[50]

Given the state of flux in the capacity markets and the fact that prices are going up, the 2.5% escalator, and the averaging of five years' worth of RA prices, which includes all types of resources, including small QF capacity with larger, more dispatchable facilities, strikes an appropriate balance between over- and under-estimating the utilities' avoided costs and the fact that variations in the markets are likely to occur over the possible 12 year term of the contract.

In adopting this avoided cost pricing methodology, the Commission has considered, to the extent practicable, each of the factors set forth in 18 C.F.R. § 292.304(e). We find that these determinations are consistent with federal avoided cost regulations, including 18 C.F.R. § 292.304(e), because, among other things: (1) they reflect the cost of capacity the Investor Owned Utilities will actually incur over a five year period; (2) the market-based nature of the RA prices take daily and seasonal peak periods into account; (3) the use of NQC to establish the capacity payment to the QF reflects the ability of the utility to dispatch the QF and the reliability of the QF to the system; and (4) the locational nature of the prices takes into account the individual generator's value to the utility and the costs of line losses.

[50] Energy Division report on "The State of the Resource Adequacy Market" issued September 3, 2019 in R.17-09-020.

5.3. Energy Price at Time of Delivery

5.3.1 Determination

For the energy price determined at the time of delivery (18 C.F.R. § 292.304(d)(2)(i)), we adopt the Staff Proposal to use hourly LMPs from the CAISO's day-ahead market for the APNode specific to the QF.

The Investor Owned Utilities shall each identify the publicly available source for these CAISO prices in their Tier 1 advice letter filings submitted on the first business day of March each year until all contracts under the New QF SOC have terminated.[51]

5.3.2. Rationale

The Staff Proposal recommended establishing the avoided cost price for the energy price at the time of delivery based on hourly prices from the CAISO's day-ahead market, and provided two price options to choose from – DLAP or LMP. (Staff Proposal at 18.) It explained that "[t]he day-ahead hourly market prices represented by DLAP would be an aggregated number, but the LMP would be specific to the QF resource and may be more accurate." (*Id.*) The Staff Proposal also noted that day-ahead market prices may become more granular over time, leading to negative energy prices in some hours due to excess energy on the system. It proposed that "these negative prices apply in these hours or 15-minute increments." (*Id.*)

As Staff correctly observes, and as discussed in Section 5.1 above, the LMP approach is more precise because it reflects an average price of all generation available at the QF's location, therefore more accurately reflecting the purchasing

[51] This information is currently available to the public for download at OASIS.CaISO.com.

utility's avoided cost at that location. We accordingly adopt the more precise LMP approach rather than the DLAP approach, which reflects a more aggregated price.

As provided in Section 5.5 below, this same price would also be available to QFs providing as-available energy without a contract. (18 C.F.R. § 292.304(d)(1).)

In adopting this avoided cost pricing methodology, the Commission has considered, to the extent practicable, each of the factors set forth in 18 C.F.R. § 292.304€. We find that these determinations are consistent with federal avoided cost regulations, including 18 C.F.R. § 292.304€, because, among other things: (1) the LMP prices adopted accurately reflect the utilities' actual avoided costs for energy, as they procure from the CAISO's day-ahead markets when they have a need for additional energy; (2) the market-based nature of the day-ahead LMP prices takes daily and seasonal peak periods into account; and (3) the locational nature of the LMP prices takes into account the individual generator's value to the utility.

5.4. Capacity Price at Time of Delivery

5.4.1. Determination

For the capacity price determined at the time of delivery (18 C.F.R. § 292.304(d)(2)(i)), we adopt the same methodology set forth in § 5.2 above, which reflects the Staff Proposal to use an average of publicly available RA prices set for the next five years, that are then shaped by applying the Commission's most recently approved capacity allocation factors, and TOU factors, and updated with the most recently approved factors on an annual basis. (Staff

Proposal at 18.) The difference is that QFs electing a time of delivery contract will receive a capacity price that is recalculated each March based on changes in the cost of RA (if a new Resource Adequacy Report is available) and/or capacity allocation factors, and TOU factors.

To this end, the Investor Owned Utilities shall each identify the capacity prices and submit them to the Commission by Tier 2 advice letter within 30 days of the issuance of this order. The prices shall be based on the capacity prices derived from the annual Resource Adequacy Reports, and modified as provided in Section 5.2 above. The resulting number is the As-Delivered Capacity Price that a facility will be paid expressed in $/kWh for each period.

The Investor Owned Utilities shall update these capacity prices by Tier 1 advice letter annually on the first business day of March until all contracts with this pricing provision are terminated.

5.4.2. Rationale

Like the proposed avoided cost for capacity at the time of contract execution, the Staff Proposal suggests relying on an average of RA market prices that are publicly available in Energy Division's annual Resource Adequacy Report published on the Commission's website. The difference is that for capacity priced at the time of delivery, the Staff Proposal suggests that the average of the RA market prices should be updated annually using the most currently available 5 year average RA prices, adjusted by the Commission's most currently determined capacity allocation factors, and TOU factors. In contrast, the capacity price at the time of execution will be locked in place for the term of the contact. The Staff Proposal explains:

> …[T]he capacity allocation factors would need to be updated to reflect more recent Commission decisions on TOU periods and loss-of-load probabilities on a yearly basis. This process would involve: 1) identifying Commission approved generation capacity allocation factors, 2) identifying Commission approved time-of-use periods, and 3) allocating adopted capacity costs to the time of use periods based on the generation capacity allocation factors. (Staff Proposal at 18.)

As mentioned in Section 5.2 above, the Joint Proposal supported the use of an average of RA prices as reported in the Annual Resource Adequacy Report to establish the avoided cost of capacity payments, but it did not specify whether its support was for capacity at time of execution, time of delivery, or both.

For the same reasons provided in Section 5.2, and given no objections to the Staff Proposal, we adopt the Staff Proposal's methodology for establishing the avoided cost of as-available capacity.

5.5. As-Available Energy Price at Time of Delivery

For as-available energy that is not subject to a legally enforceable obligation (18 C.F.R. § 292.304(d)(1)), we adopt the Staff Proposal to use the same pricing methodology adopted for the time of delivery price established pursuant to 18 C.F.R. § 292.304(d)(2)(i) for the New QF SOC and described in Section 5.3 above. That methodology, which relies on the hourly LMPs from the CAISO's day-ahead market, is an appropriate avoided cost for as-available energy that is not subject to a legally enforceable obligation for the same reasons described in Section 5.3 above.

6. Discussion and Analysis - Non-Price Terms for the New QF SOC

The QF OIR proposed to start with the non-price terms provided in the QF Settlement SOC set forth as Exhibit 6 to Attachment A of D.10-12-035. OIR at 1. It asks whether PURPA requires modification of any of the non-price terms in the QF Settlement SOC before incorporating them into the New QF SOC. (OIR at 2.) While the parties did not identify any non-price terms *requiring* modification to ensure PURPA compliance, they proposed modification or clarification of several non-price terms in the QF Settlement SOC for adoption in the New QF SOC. We address those proposals below.

6.1. Contract Duration

6.2. Determination

We adopt a maximum 12-year term for new QFs and a maximum 7-year term for existing QFs, with the seller designating the start and end dates.

6.2.1. Rationale

The Order Instituting Rulemaking for this proceeding proposed to start with the non-price terms of the existing Qualifying Facility and Combined Heat and Power Program Settlement Agreement standard offer contract (QF/CHP Settlement SOC). The Staff Proposal did not include a proposed modification to the maximum contract duration of the QF/CHP Settlement SOC, which is 7 years for existing and 12 years for new facilities.

The Joint Proposal recommends that the duration of the New QF SOC range from a 12-month (one year) minimum to a 36-month (three year) maximum. (Joint Proposal at 3-4.) We presume these proposed terms apply to both new and existing QFs. According to the Joint Parties, this relatively short term is necessary to mitigate uncertainty and related risks in the electricity markets resulting from significant recent changes, including shifts in generation from gas fired plants to renewables, the rise of Community Choice Aggregators, and increased behind-the-meter generation and large-scale energy storage. (*Id.*)

In contrast, Green Power quotes FERC's decision in *Windham Solar, LLC,* 157 FERC ¶61,134 (2016) ("*Windham*"), where FERC agreed with commenters that "'stressed the need for certainty with regard to return on investment in new technologies'" and found that "[g]iven this 'need for certainty …' coupled with Congress' directive that the Commission 'encourage' QFs, a legal enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors." (Green Power Opening Comments at 19, citing *Windham* at 8.) Green Power rejects both a 3-year and a 12-year term, suggesting that even the 12-year term in the QF Settlement SOC "is too short to provide assurances of finance ability." (Green Power Opening Comments at 3 and 19.) It recommends that QFs be provided the choice of 12, 20, or 25-year terms. (*Id.*) Green Power explains that the 12-year term "will not encourage renewable energy" and that the existing terms in the QF Settlement SOC "will only work for existing QFs seeking new contracts." (*Id*. at 3.)

In Reply Comments, Green Power reiterates that it "cannot accept the very short 3-year contract term" in the Joint Proposal and recommends instead terms of 10, 15, and 20 years. (Green Power Reply Comments at 11.) It also reiterates that "[t]he longer term is required by binding precedent" as discussed in its Opening Comments. (*Id*.)

Winding Creek argues that "the Commission knows[] a minimum 20-year contract term is needed for a viable contract that can encourage QF generation." (Winding Creek August 31, 2018 Comments at 7) and it questions whether a three-year term would comply with PURPA. (Winding Creek Opening Comments at 3.) It cites FERC's *Windham* decision for the proposition that "FERC has ruled that the term must [] *at a minimum* be equal to what is needed to finance the project." (*Id*. at 6, emphasis in original.)

In response, the Joint Parties argue that *Windham* expressly acknowledges that FERC's regulations do not "specify a particular number of years for such legally enforceable obligations." (*Windham* at 8, fn. 13.) They explain that "FERC concedes that it is a state commission's discretion in implementing PURPA on the appropriate length for a QF contract." (Joint Parties Reply Comments at 4, fn. omitted, citing *Windham* at 8.)

The Joint Parties are correct that *Windham* finds that states have discretion to determine the term of a QF contract when implementing PURPA. Thus, in this regard, *Windham* is consistent with the United States Supreme Court's and the Ninth Circuit's determinations that states have broad discretion to implement PURPA. *FERC v. Mississippi*, 456 U.S. 742, 749-51 (1982); *IEP*, 36 F.3d at 856. Even FERC will not second-guess a state's avoided cost rates. *CPUC*, 133 FERC at P 24. However, Green Power is also correct that PURPA, as interpreted in *Windham,* finds that the term for a new QF should be long enough to allow a QF a reasonable opportunity to attract capital from potential investors.[52]

On October 22, 2019, Administrative Law Judge (ALJ) Allen issued a Ruling providing additional information regarding the appropriate contract duration for new electric generation projects and providing an opportunity for Parties to file and serve supplemental comments to enable the Commission to determine the most appropriate term length for the new SOCs developed in this proceeding.[53] Parties reiterated their previously submitted comments received on the November 8, 2018 Scoping Memo and did not add any new information to the record. Recently executed contracts that were included in the ALJ Ruling, with terms ranging from 10 to 20-years, affirm that a twelve-year maximum term for new QFs would provide adequate certainty with regard to a QFs return on investment and allow a reasonable opportunity for new QFs to attract financing.[54]

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[52] We do not agree with Winding Creek that *Windham* goes as far as it claims, to find that a PURPA contract's term must be at least "equal to what is needed to finance the project." Indeed, looking to the financing requirements of individual QFs is antithetical to PURPA and FERC's regulations. Avoided cost rates are determined based on the next increment of energy or capacity available to the purchasing utility. Again, *Windham* says that the term for a new QF should be long enough to allow a QF a *reasonable opportunity to attract capital* from potential investors.

[53] The prices in contracts identified in this Ruling are confidential.

[54] Load-serving entities executed the following recent energy procurement contracts with 10 or 12 year terms: Apple Valley Choice Energy, Lancaster Choice Energy and Rancho Mirage Energy Authority – wind contracts totaling 21MW with the same generating facility for 10 year term; Redwood Coast Energy Authority – 2MW solar PV contract for 10 years; Calpine Energy Solutions, 20MW solar PV contract for 10 years; Marin Clean Energy – 42 MW wind contract for 12 years and 125 MW wind contract for 12 years. (Ruling dated October 22, 2019).

As described above, no party at the PHC suggested that hearings in this proceeding were necessary, or that there were any issues of material fact to resolve. (Transcript, v. PHC at 6-7.) Accordingly, this proceeding has focused on legal and policy issues associated with the Commission's obligations to both comply with PURPA and support the development of new renewable resources under state law.

This Commission cannot conclude that the Joint Parties' proposal for a maximum 3-year term is compliant with PURPA because the record in this proceeding does not show that a 3-year contract term provides a reasonable opportunity for a project to attract financing from potential investors.

The maximum 20-year term proposed by Winding Creek (and by Green Power as one of several proposed terms) evidently is not the term needed for financing and development of new generation. For example, many new generation projects provided in ALJ Allen's October 22, 2019 Ruling have contracted for 10-, 12-, and 15-year terms, suggesting that a 20-year term is not needed to enact FERC's guidance that the term "should be long enough to allow QFs reasonable opportunities to attract capital from potential investors." (*Windham* P 8). PURPA does not require the Commission to choose the longest term or even to average the terms.

Therefore, based on the recent history of varying term lengths, and the State's discretion to implement PURPA, we find it reasonable to adopt a 12-year maximum term for new QFs and a 7-year maximum term for existing QFs, consistent with the QF Settlement SOC. For both new and existing QFs, the contract term may be any time shorter than these maximum periods, at the discretion of the seller.

6.3. Availability of the New QF SOC

6.3.1. Determination

The New QF SOC shall be available to all QFs of 20 MW or less until suspended by the Commission's Executive Director. Justifications for a future suspension could include, but are not limited to, the following:

- Changes to PURPA, Rulemakings related to PURPA, or any changes FERC makes to PURPA implementation, or
- Determination by the Commission's Executive Director that the New QF SOC is not necessary under PURPA.

6.3.2. Rationale

The Joint Proposal recommends that the New QF SOC be available until December 31, 2020, alleging that this is when the availability of the QF Settlement SOC ends. It reiterates that nothing in the New QF SOC "would be considered binding for purposes of any new agreement to replace the existing" QF Settlement SOC. (Joint Proposal at 8.) The Joint Proposal provides no meaningful explanation for why the New QF SOC would only be available for 9 months or less, and is therefore unpersuasive.

Federal law requires this Commission to comply with PURPA. FERC has been clear that the Commission must have a PURPA program in place that complies with its regulations and is available to all QFs. Consequently, the New QF Contract is necessary for the Commission to meet its PURPA obligations. It shall therefore be available until such time as it is not necessary, as determined by the Commission's Executive Director.

6.4. Obligation to Provide Substitute RA in the Event of an Outage

6.4.1. Determination

The New QF SOC shall specify that the Buyer will not be obligated to provide substitute RA or to minimize any Resource Adequacy Availability Incentive Mechanism (RAAIM) in the event of an outage.

6.4.2. Rationale

The Joint Proposal recommends that the New QF SOC specify that the Buyer has no obligation to provide substitute RA or minimize RAAIM in the event that the Seller's generating facility is on outage and no party opposed this term. (Joint Proposal at 6.)

6.5. Notification Prior to Commercial Operation to Receive Capacity Payment

6.5.1 Determination

The New QF SOC shall include a provision requiring the Seller to provide a seventy-five day notification before the first month of commercial operation in order to receive a capacity payment for that month.

6.5.2. Rationale

As the Joint Proposal explains, "the CAISO RA timeline requires that the IOU include NQC for the facility in its RA supply plan 45 days prior to start of the month in order to receive any benefit from the capacity of the generation resource." (Joint Proposal at 7.) Requiring this notification supports compliance with RA requirements, and ensures prompt payment for capacity at the time of commercial operation.

6.6. CAISO Charges/Revenues

6.6.1. Determination

The New QF SOC shall specify that the Seller shall receive: (1) CAISO revenues and charges associated with the delivery of any Additional Dispatchable Capacity into the CAISO markets; and (2) any RAAIM benefits or charges.

6.6.2. Rationale

These terms were proposed by the Joint Parties. Receipt of revenues and charges associated with the delivery of Additional Dispatchable Capacity is consistent with the terms of the QF Settlement SOC. Receipt of RAAIM benefits is consistent with market practices for capacity transactions. No party objected to these proposals.

6.7. Contract Termination Rights

6.7.1. Determination

Consistent with the QF Settlement SOC, no contract termination rights will be provided in the New QF SOC.

6.7.2. Rationale

As the Joint Proposal explains: "(c)ontract terminations have important ripple effects on a Buyer's RA positions, hedging and risk management, dispatch systems, accounting and financial planning." (Joint Proposal at 7.) Contract termination rights may encourage disruption in resource planning, and are not necessary given the flexibility of term provisions in the New QF SOC. No party objected to this proposal.

6.8. Economic Curtailment

6.8.1. Determination

The New QF SOC shall allow for economic curtailment provisions consistent with existing RPS agreements.[55]

6.8.2. Rationale

The Joint Proposal argues that "[i]nclusion of 'take or pay' economic curtailment provisions consistent with existing RPS agreements is a reasonable approach to assist in mitigating the risk of using historical prices as the basis for future payments." (Joint Proposal at 8.) The Joint Proposal summarizes that "Buyer pays for deemed delivered energy to have economic bidding and curtailment rights." (Id. at 10.) No party opposed this proposal.

6.9. Application of the QF Settlement Term Sheet

We note that application of the QF Settlement SOC is informed by various non-price provisions of the QF Settlement Term Sheet (Term Sheet) that was approved with that SOC in D.10-12-035, as modified by D.15-06-028. For example, § 4.10 of the Term Sheet, rather than the SOC, identifies the processes for Commission approval of the contracts and any material modification to the contracts. Other provisions of the Term Sheet would not be applicable, such as the Goal and Objectives in Section 1, the Transition PPA Matters in Section 3, and the provisions regarding the Short Run Avoided Cost Pricing Structure in Section 10.[56]

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[55] A good example of this in an existing RPS agreement can be found in Sections 3.4(b) and (c) (under "Dispatch Notices") of SDG&E's 2018 RPS Long-Term Model Power Purchase Agreement.

[56] This listing is illustrative and is not intended to be comprehensive.

In order to ensure that important non-price substantive terms intended to apply to the QF Settlement SOC are carried through to the New QF SOC, we clarify here that the New QF SOC should provide that where any non-price issue is not expressly addressed in the New QF SOC, the applicable provisions of the Term Sheet shall control.

We note that this determination is consistent with the initial proposal set forth in both the OIR and the Scoping Memo to rely on the terms of the QF Settlement SOC where appropriate, that no party has objected to this proposal, and that it is consistent with the Joint Proposal's suggestion to rely on the provisions of the QF Settlement SOC (what it refers to as the "QF/CHP PPA") for several specific issues, such as designation of the scheduling coordinator, scheduling coordinator fees, energy scheduling, and interconnection. (Joint Proposal at 10 (Position Summary).)

7. Discussion and Analysis - Cost Allocation

The Scoping Memo found that cost allocation was also an issue that fell within the scope of the proceeding. The Staff Proposal did not address this issue. The Joint Parties propose "use of the [Power Charge Indifference Adjustment] (PCIA) mechanism as adopted by the Commission in D.18-10-019, but non-vintaged, *i.e.*, without respect to when the customer departed, as all customers benefit from compliance with federal law regardless of their departure date." (Joint Proposal at 8.)

Public Advocates supports this proposal, TURN does so on an interim, non-precedential basis (Public Advocates Reply Comments at 1; TURN Reply

Comments at 1), and no party objects to it. Consequently, we adopt this proposal.

8. CASMU Issues

CASMU, on behalf of several small and multi-jurisdictional utilities, filed comments on both September 12, 2018 and November 14, 2018, raising similar arguments, specifically that: "[T]he CASMU utilities should be exempted from this proceeding, or, in the alternative, should be addressed in a later, separate track for a variety of reasons…" (CASMU Opening Comments at 1.) In general, CASMU argues that the small and multijurisdictional utilities are very different from the large California utilities, the QF scheme previously adopted for the large utilities was not applicable to them, and that QF requirements applicable to the large utilities would not be appropriate or workable for them. (Id. at 1-5.)

No party responded to CASMU's arguments or otherwise addressed the treatment of the small and multi-jurisdictional utilities. Accordingly, at this time we have no reason or basis for changing their existing approaches to QF contracting. The small and multi-jurisdictional utilities represented by CASMU can continue utilizing their existing QF contracting approaches. If changes to the QF contracting approaches applicable to the small or multi-jurisdictional utilities become necessary, parties may file a petition for modification of this decision.

9. Comments on Proposed Decision

The ALJ's proposed decision was mailed to the parties in accordance with Section 311 of the Public Utilities Code, and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by ______________. Reply comments were filed by _______________.

10. Assignment of Proceeding

Cliff Rechtschaffen is the assigned Commissioner and Peter V. Allen is the assigned ALJ in this proceeding.

Findings of Fact

1. CAISO energy prices have remained stable over the past five years, appear to be consistent with recently executed long-term renewable energy contracts, and are consistent with the IOU's recent energy costs.

2. The weighted average price for resource adequacy provided in Table 7 of the Energy Division's RA Reports reflect prices from competitively bid contracts that are averaged over a five-year forward period, and accurately reflect the investor-owned utilities' avoided cost of capacity.

3. Hourly LMPs from the CAISO's day-ahead market accurately reflect the utilities' actual avoided costs for energy at time of delivery.

4. Capacity prices for time of delivery contracts should be updated annually as new price information is available.

5. Recent energy procurement contracts executed by Load Serving Entities have terms that range from ten to twenty years.

6. Recent energy procurement contracts executed by Load Serving Entities include multiple contracts for terms of ten or twelve years.

7. It is not clear that a maximum three-year contract duration is adequate to support the financing and development of new generation.

8. A maximum contract duration of 12 years is adequate to provide QFs reasonable opportunities to attract capital for the development of new generation.

9. Existing Qualifying Facilities do not require a specific contract duration to ensure construction financing.

10. The QF Settlement SOC has a maximum contract duration of seven years for existing Qualifying Facilities.

11. For QF contracting purposes the small and multi-jurisdictional California utilities represented by CASMU differ significantly from the three large California utilities.

12. No issues were raised relating to the QF contracting practices of the small and multi-jurisdictional California utilities represented by CASMU.

Conclusions of Law

1. The use of recent historical CAISO energy prices to forecast future energy prices is appropriate.

2. It is appropriate to use RA capacity prices to establish QF capacity prices.

3. It is appropriate to use hourly LMPs from the CAISO's day-ahead market to establish QF energy prices at time of delivery.

4. Capacity prices for time of delivery contracts should be updated annually, using relevant currently available information from RA contracts that is provided in Table 7 of the Energy Division's Resource Adequacy Reports.

5. A three-year maximum contract duration for new facilities is not consistent with PURPA.

6. A maximum contract duration for new facilities of 12 years is consistent with PURPA.

7. A maximum contract duration for existing facilities of seven years is consistent with PURPA.

8. There is no good basis in this proceeding for changing the existing approaches to QF contracting of the small and multi-jurisdictional utilities represented by CASMU.

9. Approval of the New QF SOC does not affect availability of the "Standard Contract for QFs 20 MW or Less" set forth as Exhibit 6 to Attachment A of D.10-12-035, which will remain unchanged and available to QFs of 20 MW or less pursuant to the QF Settlement terms.

O R D E R

IT IS ORDERED that:

1. The energy price identified at the time of contract execution (18 C.F.R. § 292.304(d)(2)(ii)) is calculated by use of a five-year average of publicly available California Independent System Operator locational marginal prices for the APNode specific to a qualifying facility, calculated on a monthly basis with periods based on the Commission's most recently approved time-of-use periods specific to a utility, and a collar based on prices at the relevant Energy Trading Hub.

2. The capacity price identified at the time of contract execution (18 C.F.R. § 292.304(d)(2)(ii)) is calculated by use of a five-year weighted average of publicly available resource adequacy prices for the next five years, shaped to time periods based on generation capacity allocation factors adopted by the Commission and applied to updated time-of-use periods, with a 2.5% escalation factor for each year of the contract term after the last year included in the average.

3. The energy price determined at the time of delivery (18 C.F.R. § 292.304(d)(2)(i)) is calculated using locational marginal prices from the California Independent System Operator's day-ahead market for the APNode specific to a qualifying facility.

4. The capacity price determined at the time of delivery (18 C.F.R. § 292.304(d)(2)(i)) is set by the same methodology used for capacity price at time of execution, but with the price recalculated each March based on changes in the cost of resource adequacy (if a new Resource Adequacy Report is available) and/or capacity allocation factors, and time-of-use factors.

5. For as-available energy that is not subject to a legally enforceable obligation (18 C.F.R. § 292.304(d)(1)), we adopt the same pricing methodology as adopted for the energy price at time of delivery established pursuant to 18 C.F.R. § 292.304(d)(2)(i).

6. Pacific Gas and Electric Company, Southern California Edison and San Diego Gas and Electric shall calculate initial prices in accordance with the above ordering paragraphs within 30 days of this decision and submit these prices to the Commission via a Tier 2 Advice Letter. They shall calculate revised prices by March 15th of each year via a Tier 1 Advice Letter.

7. The maximum contract duration for new Qualifying Facilities is 12 years, with the seller designating the start and end dates.

8. The maximum contract duration for existing Qualifying Facilities is seven years, with the seller designating the start and end dates.

9. The New Qualifying Facilities Standard Offer Contract shall be available to all Qualifying Facilities of 20 megawatts or less until suspended by the Commission's Executive Director.

10. Other non-price terms in the New Qualifying Facilities Standard Offer Contract shall be consistent with the discussion in Section 6 of this decision.

11. The New Qualifying Facilities Standard Offer Contract shall provide that where any non-price issue is not expressly addressed in the New Qualifying Facilities Standard Offer Contract, the applicable provisions of the Qualifying Facilities Settlement Term Sheet that was approved in Decision (D.) 10-12-035 (as modified by D.15-06-028) shall control.

12. The "Standard Contract for QFs 20 megawatt (MW)or Less" set forth as Exhibit 6 to Attachment A of Decision 10-12-035 will remain unchanged and available to QFs of 20 MW or less.

13. Cost allocation shall use a non-vintaged version of the Power Charge Indifference Adjustment mechanism adopted by the Commission in Decision 18-10-019.

14. The small and multi-jurisdictional utilities represented by California Association of Small and Multi-Jurisdictional Utilities can continue utilizing their existing Qualifying Facilities contracting approaches.

15. Each utility subject to this decision shall file a Tier 2 advice letter within 30 days of this decision with their New Qualifying Facilities Standard Offer Contract, and including a redline version comparing the new contract with the superseded prior contract.

16. This proceeding remains open to consider whether any further action is required to comply with Public Utility Regulatory Policies Act of 1978, as necessary, such as to comply with any changes in federal regulations.

This order is effective today.

Dated ______________________________, at San Francisco, California.

APPENDIX

Avoided Cost Pricing Methodologies for Capacity

Avoided Cost Pricing Methodologies

1. Capacity Price at Time of Contract Execution

To establish a QF's avoided cost for capacity at the time of contract execution, Investor Owned Utilities (IOU) shall utilize the five-year weighted average price ($/kW-month) of publicly available historic Resource Adequacy (RA) capacity prices published in the annual Resource Adequacy Report and a 2.5% escalation factor for each year of the contract term after the last year included in the five-year weighted average price of capacity.
To illustrate this calculation, we outline the steps to establish the avoided cost for a capacity QF at the time of contract execution (2019) as follows:
Facility Location: NP-26
RA Designation: Local RA
Contract Execution Year: 2019

Table 1: Capacity Prices at Time of Execution:

Capacity Year	Contract Price ($/kW-month)[57]	Escalation	Total ($/kW-month)	Total ($/kW-year)
2019	$2.89	n/a	$2.89	$34.68
2020	$2.89	n/a	$2.89	$34.68
2021	$2.89	n/a	$2.89	$34.68
2022	$2.89	2.5%	$2.96	$35.55
2023	$2.96	2.5%	$3.04	$36.44
2024	$3.04	2.5%	$3.11	$37.35
2025	$3.11	2.5%	$3.19	$38.28
2026	$3.19	2.5%	$3.27	$39.24
2027	$3.27	2.5%	$3.35	$40.22

To allocate capacity costs at time of contract execution by IOU, capacity prices shall utilize capacity allocation factors that have been adopted by the Commission and applied to revised TOU periods. Illustrative revised time-periods and TOU factors are outlined by IOU in Tables 2, 3 and 4 below. Capacity allocation factors must be updated to reflect the most recent Commission decisions on TOU periods. This would require:

1. Identifying Commission approved generation capacity allocation factors,

[57] 2018 Resource Adequacy Report at 25, Table 7: Aggregated RA Contract Prices, 2018-2022. Available at: http://www.cpuc.ca.gov/ra/. This example pulls the weighted average price ($/kW-month) for a facility located in NP-26 with a local RA obligation.

2. Identifying Commission approved time-of-use periods, and
3. Allocating adopted capacity costs to the time-of-use periods based on the generation capacity allocation factors.

Using the $/kW-year value derived identified above, the capacity calculation at time of execution can be calculated as follows:

$$C_{ToE} = (CAF / H) \times RA$$

Where:

C_{ToE} = Capacity Price at Time of Execution, expressed in $/kWh.

CAF = Capacity Allocation Factor, which allocates the capacity value for seasons and time-of-delivery periods.[58]

H = The number of delivery hours that comprise the applicable Time-of-Use period which was used to calculate the Capacity Allocation Factor.

RA = Capacity Price in $/kW-year, as calculated in Table 1 for a given RA obligation type and zone, derived from the most current annual Resource Adequacy Report prepared by Energy Division.

The resulting number is the Capacity Price that a facility will be paid expressed in $/kWh for each period.

Tables 2, 3 and 4 outline an illustrative capacity price for PG&E, SCE and SDG&E (accounting for TOU periods by IOU) for a facility located in NP-26 designated as Local RA in 2019 (continuation of above example).

[58] Capacity allocation factors allocate the capacity value for seasons and time-of-delivery periods. These factors are derived by using the most recently adopted time-of-use periods and the most recently adopted capacity allocation factors, dividing the allocation percentages effective January 1, 2019, and approved in D.97-03-017 by the number of hours in each time-of-delivery period.

Table 2: Illustrative PG&E Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Price at Time of Execution ($/kW – year)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (Jun – Sep)				
Peak	76.19%	610	$34.68	0.0433
Partial Peak	2.38%	488		0.0017
Off-Peak	0.02%	1,830		0.0000
Super Off-Peak	NA	NA		
	78.59%	2,928		
Winter (Jan – May and Oct – Dec)				
Peak	21.25%	1,215	$34.68	0.0061
Partial Peak	0.00%	NA		
Off-Peak	0.00%	4,157		0.0000
Super Off-Peak	NA	460		
	21.41%	5,832		
Without Time-of-Delivery Metering				
Summer	78.59%	2,928	$17.34	0.0047
Winter	21.41%	5,832		0.0006

Table 3: Illustrative SCE Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Price at Time of Execution ($/kW – year)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (Jun – Sep)				
Peak	71.68%	420	$34.68	0.0592
Partial Peak	12.40%	190		0.0226
Off-Peak	0.24%	2,318		0.0036
Super Off-Peak	NA	NA		
	84.32%	2,928		
Winter (Jan – May and Oct – Dec)				
Peak	NA	NA	$34.68	0.0041
Partial Peak	14.24%	1,215		0.0114
Off-Peak	0.88%	2,673		0.0100
Super Off-Peak	0.56%	1,944		
	15.68%	5,832		
Without Time-of-Delivery Metering				
Summer	84.32%	2,928	$17.34	0.0050
Winter	15.68%	5,832		0.0005

Table 4: Illustrative SDG&E Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Price at Time of Execution ($/kW – year)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (May - Sep)				
Peak	72.79%	765	$34.68	0.0330
Partial Peak	NA	0		
Off-Peak	5.86%	1,613		0.0013
Super Off-Peak	NA	1,294		
	78.65%	3,672		
Winter (Jan – Apr and Oct – Dec)				
Peak	5.84%	1,060	$34.68	0.0019
Partial Peak	NA	0		
Off-Peak	15.51%	2,056		0.0026
Super Off-Peak	NA	1,972		
	21.35%	5,088		
Without Time-of-Delivery Metering				
Summer	78.65%	3,672	$17.34	0.0037
Winter	21.35%	5,088		0.0006

2. Capacity Price at Time of Delivery

The capacity price at time of delivery shall be calculated in $/kWh using the methodology identified for time of contract execution, as described in the section above[59]. Updated annually by advice letter, the capacity price at time of delivery shall utilize the average of the historic RA prices using the most currently available five-year weighted average price of capacity,[60] adjusted by the Commission's most currently determined capacity allocation factors and time of use factors.

For consistency, Table 5 outlines illustrative capacity allocation factors and time-of-use periods used to shape the appropriate five-year weighted average price of capacity.

[59] Except for the 2.5% escalation factor is not applied, because these prices are updated annually.

[60] The most recent five-year weighted average can be found in the 2018 Resource Adequacy Report at 25, Table 7: Aggregated RA Contract Prices, 2018-2022. Available at: http://www.cpuc.ca.gov/ra/.

Table 5: Illustrative As-Available Capacity Allocation Factors for Time of Delivery Contracts

	PG&E		SCE		SDG&E	
	Capacity Allocation Factor	Hours	Capacity Allocation Factor	Hours	Capacity Allocation Factor	Hours
Summer	**Jun – Sep**		**Jun – Sep**		**May - Sep**	
Peak	76.19%	610	71.68%	420	72.79%	765
Partial Peak	2.38%	488	12.40%	190	NA	0
Off-Peak	0.02%	1,830	0.24%	2,318	5.86%	1,613
Super Off-Peak	NA	NA	NA	NA	NA	1,294
	78.59%	2,928	84.32%	2,928	78.65%	3,672
Winter	**Oct – May**		**Oct – May**		**Oct - Apr**	
Peak	21.25%	1,215	NA	NA	5.84%	1,060
Partial Peak	0.00%	NA	14.24%	1,215	NA	0
Off-Peak	0.00%	4,157	0.88%	2,673	15.51%	2,056
Super Off-Peak	NA	460	0.56%	1,944	NA	1,972
	21.41%	5,832	15.68%	5,832	21.35%	5,088
Without Time-of-Delivery Metering						
Summer	78.59%	2,928	84.32%	2,928	78.65%	3,672
Winter	21.41%	5,832	15.68%	5,832	21.35%	5,088

3. Energy Price at Time of Execution

As described in the Decision, the energy price identified at time of execution shall be a five-year average of publicly available CAISO LMPs at each APNode, calculated on a monthly basis with periods based on the Commission's most recently approved standard time-of-use periods specific to the utility. These prices will be subject to a +/- 10% collar based on prices at the relevant Energy Trading Hub in which the facility is located (either NP 15 or SP 15).

Each Investor Owned Utility shall file a Tier 2 advice letter within 30 days of the issuance of this order containing a working Excel file with columns containing the following information:

- All Aggregated Pricing Nodes ("APNodes") in its service area;
- The five-year historical average of LMPs for each APNode based on the 60 months from January 2014 through December 2018, calculated on a monthly basis for each TOU period as defined above;
- The five-year historical average of the applicable Energy Trading Hub prices (NP 15 or SP 15), calculated in the same manner as the LMPs;
- The potential +/- 10% collar applicable to each APNode based on the five-year historical average of the applicable Energy Trading Hub prices, calculated on a monthly basis for each TOU period; and

- The resulting energy prices available to QFs at each APNode by month and TOU period.

Each Investor Owned Utility shall display this information in three tabs, as shown by example below.

Tab 1 – 'Final Prices'

APNode	NP-15/SP-15	January Peak	January Off-Peak	January Shoulder-Peak	February Peak	…
APNode-1	NP-15	28.20	30.54	45.81	21.15	
APNode-2	NP-15	25.16	29.12	42.62	44.56	
APNode-3	SP-15	29.31	27.67	45.88	37.18	
…						

Tab 2 – 'APNode averages'

APNode	January Peak	January Off-Peak	January Shoulder-Peak	February Peak	…
APNode-1	28.20	30.54	45.81	21.15	
APNode-2	25.16	29.12	42.62	44.56	
APNode-3	29.31	27.67	45.88	37.18	
…					

Tab 3 – 'Trading Hub collars'

APNode	January Peak	January Off-Peak	January Shoulder-Peak	February Peak	…
NP-15 – 10%	38.116	23.976	26.159	36.459	
NP-15	42.351	26.640	29.066	40.510	
NP-15 + 10%	46.586	29.304	31.973	44.561	
SP-15 – 10%	39.91	34.61	32.83	35.43	
SP-15	44.34	38.46	36.48	39.37	
SP-15 +10%	48.77	42.30	40.12	43.30	

Where:

- 'Final Prices' – indicates the tab where prices are listed, as expressed in $/MWh, that a facility would receive for each hour it generates in each applicable month and TOU period.
- 'APNode Averages' – indicates the tab where the five-year historical average of LMPs for each APNode based on the 60 months from January 2014 through December 2018 are listed, calculated on a monthly basis for each TOU period.
- 'Trading Hub collars' – indicates the tab where the five-year historical average of each Energy Trading Hub prices (NP-15 and SP-15) calculated in the same manner as the LMPs, as listed, as well as the potential +/- 10% collar.
- 'APNode' – indicates the column where the utility lists every APNode in its service territory.

- 'NP-15/SP-15' – indicates the column where the utility identifies the applicable Energy Trading Hub for each APNode.
- 'January Peak', 'January Off-Peak', 'January Shoulder-Peak,' and 'February Peak' – represent the method in which the utilities shall label each column with each month, January through December, and the TOU periods in that month.

(END OF APPENDIX)