BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program	Rulemaking 11-05-005 (Filed May 5, 2011)

FUELCELL ENERGY, INC. REPLY COMMENTS TO SEC. 399.20 RULING OF JUNE 27, 2011

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In accordance with the June 27, 2011 Administrative Law Judge's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1X Amendments to Section 399.20 ("Ruling"), FuelCell Energy, Inc. ("FCE") submits the following reply comments. FCE looks forward to working with the Commission and other stakeholders to complete implementation of SB 32.

I. Introduction

After reviewing opening comments it seems important to clarify from the outset: SB 32 did not create a new program, and does not oblige the Commission to develop an entirely new tariff, contract and rules. SB 32 made a few modest, but very important, changes in Public Utilities Code section 399.20, including adjustments to the parameters for pricing and increasing the maximum project capacity to 3 megawatts ("MW").

FCE is confident that if the Commission implements SB 32 consistent with the terms of the statute and the Federal Energy Regulatory Commission's ("FERC's") recent clarifying orders addressing the calculation of avoided cost feed-in tariff ("FIT") rates, the program will be a success. The Commission should reject proposals from the investor-owned utilities ("IOUs") and some other stakeholders that selectively ignore key language in Section 399.20 and the recent FERC rulings. The Commission should also resist the suggestion of some stakeholders to turn the renewable feed-in tariff into a clone of the existing renewable portfolio standard ("RPS"), renewable auction mechanism ("RAM") or photovoltaic solar ("PV") auctions. Each of these existing programs will play a useful part in helping California meet its ambitious 33 percent renewables portfolio standard goal. But they were designed for participation by larger generators, and in the case of the PV programs, for a single well established technology. The SB 32 program was designed to complement the other RPS programs. It was designed to encourage development of small, diverse distributed generation ("DG") resources that are located near load centers and that cannot participate in the existing RPS auctions because of their scale, project economics, or because they are owned by customers, farmers or public agencies rather than large developers.

The Commission should continue to keep this fundamental objective in focus as it addresses outstanding issues and proposals. In particular the Commission should very carefully consider how to ensure a measure of diversity in the SB 32 program. Of particular importance are the issues of pricing for baseload renewable resources and the proposed allocation for biogas projects, which provide unique benefits to the state of California, but also have unique challenges in terms of development time and project economics. The Commission's decision on these two issues will determine whether there will be a place in the program for digester gas projects and fuel cells.

II. Program Scope, Design and Eligibility

A. The Commission should allocate a portion of the program for baseload biogas projects.

FCE and a number of other parties have proposed and discussed in their briefs and opening comments the justification for establishing a reasonable program allocation or "carve out" for baseload biogas projects. While SB 32 does not address specifically the allocation of program capacity between technologies, it clearly does not preclude the Commission from doing so, and a baseload biogas allocation will serve the key goal of ensuring at least a minimal degree of diversity in the program.

FCE agrees with AECA that "in order to realize the benefits of bioenergy, and ensure that all eligible technologies are provided a meaningful opportunity to participate in the FiT program," the Commission should reserve an allocation to "incubate" biogas generation projects at California dairy, food processing, and wastewater treatment facilities.[1] As the California Wastewater Climate Change Group observes, "[b]iogas energy has a unique role to play in providing clean, firm-capacity renewable electricity. Biogas power supports electrical grid stability and requires no grid system storage or dispatchable power capacity elsewhere on the transmission system for support with changes in weather."[2]

The Sierra Club correctly points out in its opening comments that setting procurement targets (together with appropriate pricing) "helps to promote a balanced portfolio and renewable resources that balance generation and grid operations, and cost containment" and will "increase electricity security and reliability"[3] The Sierra Club's proposed creation of technology-specific "buckets" is interesting and conceptually consistent with the baseload biogas carve-out proposed by FCE and others.[4] However, given the relatively small size of the SB 32 program, once split up between the IOUs and POUs, the fine-tuned allocations according to project size and technology may not be practical. Alternatively, unless and until the 750 MW cap is eliminated or expanded, the Commission could focus on simpler means of ensuring a degree of diversity such as the 20 percent baseload biogas carve out. If the Commission decides to adopt the Sierra Club's proposal, the allocation should be by capacity, not by kWh, in order to ensure that baseload resources are not relegated to a small corner of the program as a function of their higher capacity factor.

B. The project size cap should be 3 MW.

Section 399.20(j)(2) authorizes the Commission to reduce the three megawatt capacity limitation established in section 399.20(b)(1) if it "finds that a reduced capacity limitation is

[1] AECA Comments at 2.
[2] CWCCG Comments at 2.
[3] Sierra Club Comments at 8-9.
[4] Id. at 9.

necessary to maintain system reliability within that electrical corporation's service territory."[5] SDG&E wants to limit the program to projects 1.5 MW or smaller.[6] However, in the absence of a showing that the limitation is "necessary to maintain system reliability" within SDG&E's territory, the Commission should not grant SDG&E's request. If the Commission concludes that SDG&E's concerns regarding the impact of intermittent resources on its system justify a limit, that limit should not be applied to baseload resources. Likewise, the Commission should simply dismiss the Clean Coalition's request that the Commission use its "inherent authority" to expand the size cap to 5 MW.[7] The Clean Coalition offers no justification relating to the purpose of SB 32, but instead cites as its "key rationale" the expansion of fast track interconnection eligibility by PG&E and CAISO.[8] If SB 32 were not a relatively small program this proposal might have merit. Since the program is very limited in scope and capacity, projects should be limited to 3 MW or less.[9] On a related note, FCE supports the recommendation that the Commission clarify that the capacity of existing or separate DG projects on the same site will not be counted in applying the 3 MW limit or the limits on support from other programs addressed in Section 399.20(k).

[5] Cal. Pub. Ut. Code § 399.20(j)(2).
[6] SDG&E Comments at 12.
[7] Clean Coalition Comments at 8.
[8] Id. The Clean Coalition's recommendation appears also to be driven by its prediction that "the SB 32 program will be dominated by projects at or close to 3 MW unless additional pricing options are included to support smaller projects." Id. at 17. It is certainly true that if the Commission adopts the Clean Coalition's proposals on pricing the program may only work for the Clean Coalition's apparent constituency – larger solar PV projects. But as discussed herein, this should *not* be the program's objective and hopefully will not be the outcome of this proceeding.
[9] As noted in opening comments, FCE is not opposed to the phase-in proposed by CalSEIA (CalSEIA Comments at 6) as long as it is specifically applied to solar PV and not to fuel cells.

C. A "sunset date" is neither necessary nor appropriate.

PG&E requests that the Commission establish January 1, 2014 as a "sunset date" for the SB 32 program.[10] PG&E's expectation, apparently, is that the IOUs may contract for so many large renewable projects through the "RAM Program, RPS Solicitations, IOU-specific programs (such as PG&E's PV Program), and bilateral negotiations" that they will have satisfied their 33% statutory RPS requirement by 2014. Thus, from PG&E's perspective, it would no longer be "necessary or appropriate" for the IOU to offer the renewable feed-in tariff to eligible projects, even if the program has not reached its very modest capacity limit. The sunset would, according to PG&E, provide "clarity" as to when the program will end.[11]

The Commission should reject PG&E's suggestion and clarify that the IOUs have an ongoing responsibility to include the full implementation of SB 32 as an assumption in their resource planning. The Commission should also clarify that the capacity set aside for any Section 399.20 project that does not come on line will be returned to the program.

D. The Commission should adopt appropriate conditions to discourage gaming.

FCE agrees with CalSEIA, PG&E and TURN that the Commission should adopt appropriate program conditions to prohibit gaming.[12] PG&E's proposal to prevent projects from terminating one section 399.20 contract and immediately signing another for the same project is reasonable, but needs a case-by-case exception for worthy projects that encounter permitting delays or other unanticipated obstacles resulting in contract termination solely due to failure to meet the development deadline. The Commission should explicitly reserve the right to adjust the concentration limit and anti-gaming rules as necessary to meet program objectives and address new issues as they may arise.

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[10] PG&E Comments at 25.
[11] Id.
[12] *See* CalSEIA Comments at 15; PG&E Comments at 25-26, TURN Comments at 7.

III. Pricing

A. The Commission has the authority under SB 32 and PURPA to set technology or product-differentiated rates.

Most parties appear to be in agreement that SB 32, the market pricing guidelines in SB 2 1X and PURPA afford the Commission useful guidance and considerable flexibility in formulating rates for projects under Section 399.20. A few parties disagree, suggesting for example, that terms such as "market price" should be read as limiting the Commission's discretion to differentiate prices according to the avoided cost and/or value to ratepayers of the resource or product.[13] To focus the conversation about pricing, it is important that the Commission address from the outset the scope of its rate-setting authority under the applicable statutes, regulations and applicable case law.

Section 399.20(d)(1) requires that the renewable FIT payment rate be "the market price determined by the commission pursuant to Section 399.15," including "all current and anticipated environmental compliance costs including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located." Section 399.15(c) authorizes the Commission to set a market price "in consideration of":

> (1) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission. (2) the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities. (3) The value of different products including baseload, peaking and as-available electricity.

[13] *See e.g.* SCE Comments at 5.

The Ruling points out that this language will be moved, verbatim, to Section 399.20(d) on the effective date of SB 2 1X.[14] The Commission has been authorized to adjust rates for time of delivery and to "establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit. The Commission needs to ensure that rates and charges leave other ratepayers "indifferent" (i.e. not better or worse off) as a result of the contract. And the Commission needs to set rates that are consistent with PURPA avoided cost principles and applicable regulations.[15] As some parties have pointed out, the PURPA regulations include a variety of parameters permitting variation in pricing to reflect the costs and benefits associated with different products. FERC has recently provided additional clarification that in implementing a state procurement program, a state may look to the "particular characteristics" of the relevant resources in setting avoided costs.[16]

Reviewing all of the above, it is more than clear that the Commission has broad authority to set appropriate prices for SB 32 resources. The Commission may consider fixed and variable costs associated with different types of renewable resources and variations in value between baseload and intermittent resources. As this is a renewable procurement program, the Commission also needs to determine and include in its pricing mechanism a value for the renewable attributes that will be delivered to the IOU along with capacity and energy.

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[14] Ruling at 2.
[15] FERC has recently clarified that states are entitled to set feed-in tariff prices for conventional and renewable resources, but only for qualifying facilities and generation owned by public entity sellers outside of FERC jurisdiction. See 132 FERC ¶ 61,047. This means that the prices set in this proceeding must conform to PURPA requirements and all sellers except non-jurisdictional public entities must obtain QF status to participate. See further discussion in section III.B.
[16] *See* March 7, 2011 Brief of FuelCell Energy, Inc. at 11-15.

B. The Commission should clarify that all FERC-jurisdictional sellers must be QFs and set SB 32 prices consistent with avoided cost principles.

The majority of commenting parties are in agreement that the Commission needs to establish a pricing mechanism that is consistent with PURPA, as implemented through the PURPA regulations and recently clarified by FERC. According to recent FERC orders, the Commission's jurisdiction to set feed-in tariff rates is bounded by its delegated authority under PURPA. This clearly means that any seller under SB 32 either must be a QF or a public entity that is exempt from FERC jurisdiction. It also means that the Commission needs to set renewable FIT rates that comply with PURPA, the PURPA regulations and FERC's recent orders. As some parties note, this obligation overlaps with the ratepayer indifference requirement codified in Section 399.20, and as FERC has recently explained, affords the Commission a "wide degree of latitude" in determining prices for QF resources.[17]

While the recent FERC orders are unambiguous (and are the result of the California IOUs' own request for clarification on this point), it seems the Commission needs to clarify that it is setting an avoided cost rate. PG&E says, without explanation, that "Section 399.20 is not a PURPA program," and rather confusingly offers that "the utility is not limited solely to new conventional generating facilities and there may be lower cost options available that have nothing to do with avoided costs and that would represent the utility's avoided cost.[18] SDG&E and SCE point out that FIT participants are not required under Section 399.20 to be QFs.[19] SDG&E further alleges that since the Commission has not "undertaken" the avoided cost analysis required by FERC, the Commission "may not require SDG&E to pay the

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[17] 133 FERC ¶ 61,059 ¶ 36, fn.83.
[18] PG&E Comments at 15.
[19] SDG&E Comments at 5; SCE Comments at 6. It should be noted that both SCE's and SDG&E's existing renewable FIT tariffs and PPAs *do* require participants to be QFs.

administratively set rate contemplated in § 399.20."[20] Since the June 27 Ruling only purports to serve as a "starting point for further comments by parties," it seems unfair to accuse the Commission of a failure to undertake FERC-mandated avoided cost analysis.[21] Indeed, the Ruling explicitly invites comments on "the impact of federal law on the implementation of §399.20,"[22] and many parties have done so. The Commission should clarify that it is setting an avoided cost rate, consistent with all applicable statutory requirements, PURPA regulations and FERC precedent.

C. The unadjusted MPR is not an appropriate pricing mechanism.

Most parties' comments recognize that the market price referent ("MPR"), as currently defined, does not meet the requirements of Section 399.20 or PURPA for pricing renewable resources. The MPR reflects the cost of a new utility scale fossil-fueled combined cycle generating turbine ("CCGT") and thus, by definition, does not reflect the avoided cost of distributed renewable resources. It also does not reflect the value to the ratepayer of distributed renewable resources, and thus does not satisfy the mandated indifference standard. Notwithstanding all of the above, a few parties propose using the MPR, as currently defined, to set a single price for all renewable resources procured under SB 32.

PG&E "acknowledges that different types of electricity products provide different values to customers," but maintains that the Commission's "interest in expeditiously implementing Section 399.20" outweighs the need for an accurate pricing mechanism.[23] There are two problems with this argument. First, it is based on an incorrect assumption that setting prices that reasonably reflect the difference in value to ratepayers between firm and non-firm resources

[20] SDG&E Comments at 5. See also SCE Comments at 6.
[21] Ruling at 1.
[22] Ruling at 13.
[23] PG&E Comments at 7-8.

would require lengthy hearings and a "substantial amount of time…" The Commission has both the experience and the information necessary to create a simple and workable mechanism for setting technology or product-differentiated rates. The second and more fundamental problem with PG&E's argument is that the Commission is under a statutory obligation to establish prices that reflect the utilities' avoided cost, and to meet all requirements of Section 399.20, including the obligation to ensure ratepayer indifference. The Commission cannot simply jettison that legal obligation at will.

The Utility Reform Network and Coalition of California Utility Employees ("TURN/CUE") appear to take the position that use of the MPR without adjustment or adders is appropriate because of a reference in Section 399.15 to the "long-term market price of electricity for fixed price contracts." TURN/CUE start by stating that long-term contracts are "typically" tolling agreements based on heat rates and gas prices.[24] They then extrapolate that "the legislature has explicitly decided that the §399.20 program will offer contracts with prices set at the long-term price of *conventional* resources."[25] The California Legislature has said nothing of the kind. The word "conventional" does not appear in Section 399.15(c), which rather requires consideration of the utilities' "general procurement activities," the long-term "ownership, operating and fixed-price fuel costs" associated with electricity from "new generating facilities," and the "value of different products including baseload, peaking and as-available electricity." TURN/CUE's view of legislative intent does not comport with the plain language of SB 32 and should be dismissed.

[24] TURN/CUE Comments at 2.
[25] Id. at 4.

D. The MPR with appropriate adjustments may provide a reasonable method of determining pricing for SB 32 resources

FCE agrees with a number of other parties that the Commission could use the MPR as the starting point in calculating prices that conform to the requirements of SB 32.[26] There is no single "right way" to set prices for SB 32 resources. The requirements and guidelines set out in Section 399.20 and under PURPA do not dictate a particular methodology. The Legislature *did,* however, articulate its intent with respect to pricing to help guide the Commission in considering the alternatives:

> A tariff for electricity generated by renewable technologies should recognize the environmental attributes of the renewable technology, the characteristics that contribute to peak electricity demand reduction, reduced transmission congestion, avoided transmission and distribution improvements, and in a manner that accelerates the deployment of renewable energy resources.[27]

Since renewable resources do not all offer the same environmental attributes, contributions to peak electricity demand reduction, and other benefits, differentiating prices by technology or product is entirely consistent with legislative intent. One way to accomplish this is by using the MPR as a proxy for the avoided cost of non-renewable power and using appropriate adjustments and/or adders to calculate a price that reflects the cost of procuring (and the benefits provided by) categories of renewable resources or products.

FCE acknowledged in its opening comments that the Commission could devise an MPR-based pricing methodology by using the MPR as a starting point and adding the above-MPR values provided by small renewable DG.[28] Others have voiced support for this general approach as well. As some parties observe, this approach would have the virtue of familiarity and may simplify the process.

[26] CalSEIA Comments at 9; AECA Comments at 3.
[27] Cal. Stats. (2009), Chapter 328, Section 1(e).
[28] See FCE Comments at 3-5.

A workshop would be a helpful forum for discussing assumptions and parameters for an "MPR plus" pricing approach. First, there is the question of how to value environmental attributes. PG&E's assertion that "all current and anticipated environmental compliance costs…" (per Section 399.20(d)) are already embedded in the MPR is correct only to a point. The MPR does not, for instance, include any environmental compliance costs for carbon monoxide ("CO") despite calculating the CO emissions rate for the proxy plant. In addition, the environmental compliance costs embedded in the MPR are based on statewide average emissions allowance prices. Regional emissions allowance prices vary significantly and the avoided emissions attributed to distributed renewable resources should be valued based on the difference between the region-specific emissions allowance price and the statewide average price embedded in the MPR, as was done in the CalSEIA study. This would be a good topic for discussion and clarification.

The Commission also needs to decide how to value the compliance value of renewable attributes. As CEERT notes, FERC has explicitly endorsed payment for the value of a renewable energy credit.[29] The REC represents the value of RPS-eligible renewable resources for compliance with renewable mandates. This value is separate and apart from that of avoided emissions and satisfies only a utility's renewable mandate; RECs do nothing to satisfy a utility's obligations to obtain emissions allowances for permitted emissions as determined by the applicable air quality management district.

Section 399.20(e) expressly requires the Commission to consider, and authorizes the Commission to value, location-based attributes. This reflects the stated intent of SB 32 that a renewable FIT "recognize … *reduced transmission congestion, avoided transmission and distribution improvements,* and in a manner that accelerates the deployment of renewable energy

[29] CEERT Comments at 7.

resources."[30] Further discussion of what those values are and how they may be valued is necessary in order to comply with Section 399.20(e), and inclusion of appropriate values is critical if the pricing mechanism is to correctly reflect the value of renewable DG resources.

While FCE is conceptually supportive of an MPR plus approach to determining technology or product-specific pricing, FCE also reiterates its support for basing the price for each category of renewable technology on the IOUs' avoided cost of building or procuring the same generation. As CEERT notes, basing feed-in tariff prices on the utility's cost of similar generation was explicitly endorsed in recent FERC orders addressing QF pricing.[31] This approach would have the distinct virtue of basing renewable feed-in tariff prices on the avoided cost of procuring comparable DG scale renewable resources rather than by reference to the base cost of a utility-scale non-renewable resource. The Commission clearly has information at its disposal to set technology or product-specific prices for SB 32 resources. While "black box" results of auctions for larger transmission-interconnected resources are not a viable source of information regarding the utilities' cost of procuring the smaller scale renewable resources eligible under Section 399.20, the Commission could look to available industry pricing data, bilateral contract information, or recent estimates from public sources, to determine the avoided costs associated with procurement of each category of renewable resource or product.

If the Commission does not pursue this approach to technology-specific pricing, which admittedly may be more complex than an MPR plus mechanism, the Commission should at least consider using available information regarding the actual cost of utility-owned renewable systems or relevant procurement costs as a useful reference for ensuring the reasonableness of the MPR plus pricing mechanism and demonstrating ratepayer indifference.

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[30] Cal. Stats. (2009), Chapter 328, Section 1(e) (emphasis added).
[31] CEERT Comments at 2-3.

E. SCE's proposal to use CAISO prices is not consistent with SB 32 or PURPA.

SCE proposes to pay for distributed renewable power based on the "average of the historical one-year day-ahead South Path (SP)-15 EZ Gen Hub price published by the California Independent System Operator (CAISO) plus the department of Energy (DOE) established price for renewable attributes in the Western United States."[32] The Commission should reject SCE's proposal without further consideration because it violates both Section 399.20 and PURPA requirements.

Looking first at the pricing criteria currently set forth in Section 399.15, SCE's proposal does not reflect consideration of the long-term market price for electricity for fixed price contracts, determined pursuant to SCE's procurement activities. It does not reflect the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities. It does not reflect the value of different products. SCE's proposal likewise does not include all current and anticipated environmental compliance costs (Section 399.20(d)1) and it does not reflect consideration of "a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit" (Section 399.20(e)). SCE's proposal would not ensure ratepayer indifference, since the CAISO hub price bears no relationship to the value that ratepayers would receive for the resource and there is no evidence that regional REC prices reflect the compliance value of RECs under the new California RPS rules. Last, but not least, SCE's proposed pricing mechanism would not satisfy PURPA avoided cost pricing requirements, a fact that SCE seems to acknowledge.

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[32] SCE August 5 Filing, proposed Schedule MP FiT.

F. Bids from the RAM and PV auctions are not an appropriate basis for determining pricing for baseload resources.

Vote Solar and the Solar Alliance propose to use winning bids from the RAM or PV program auctions to set prices. FCE does not comment on this proposal as a possible basis for setting prices for comparable solar PV projects, except to note that 1) there is a significant difference in eligible project size between the RAM and PV programs and SB 32, which is expressly limited to smaller projects, and 2) the IOUs have not held a single RAM auction yet, much less purchased a single kWh from a project actually built and operating under the RAM program.

As a proposal for setting prices for baseload resources under SB 32, the proposal is completely inappropriate. First, pricing data from auctions is not and will not be transparent to the public. Second, since the eligibility requirements for the programs are different from the eligibility requirements under SB 32, it is extremely unlikely that the Commission could ascertain prospectively - even for projects within the same product category – that the auction bids reflect the avoided cost of the SB 32 project. Third, at this point there is no assurance that a winning bidder in the RAM will actually build and operate a project, and so the Commission cannot rely on RAM results as any meaningful reflection of avoided cost.

G. The Net Surplus Compensation rate does not meet statutory or PURPA requirements.

The Division of Ratepayer Advocates conceptually supports a MPR-based price, but is concerned that the Commission may not update the MPR after 2011. As an alternative, DRA suggests the Net Surplus Compensation ("NSC") rate adopted in D.11-06-016 as a basis for paying net metered DG customers for net exports in years when their generation exceeds on-site use.[33] DRA does not attempt to explain in any detail how the NSC comports with the statutory requirements in Section 399.20, the indifference standard, or PURPA. Rather, DRA supports the NSC because it "utilizes publicly available data" and "never requires recalculation"[34]

DRA points to the Commission's finding in D.11-06-016 that the NSC satisfies the ratepayer indifference standard for net metered resources.[35] But DRA's suggestion that incidental exports from residential rooftop solar systems and long-term contract power from baseload SB 32 resources "provide similar value" to ratepayers is obviously not supportable. The Commission should reject DRA's proposal.

IV. Contract Terms and Conditions

A. The Commission should instruct the IOUs to continue using streamlined Section 399.20 contracts, with limited modifications consistent with SB 32.

PG&E and SCE propose to use a modified form of the current Section 399.20 PPA for projects up to 1 MW, and to replace it with the 100+ page RAM contract for all 1-3 MW projects. SDG&E proposes adding security requirements and other terms from its standard RPS agreement if the Commission turns down its request to exclude all projects larger than 1.5 MW. The IOUs' proposals should be rejected. The IOUs have offered no evidence to support their allegation that the existing PPAs are not workable for projects up to 3 MW. A complex and very lengthy PPA meant for 20 MW projects would obstruct rather than serve the Legislature's clearly expressed intent to address tariff structures and regulatory structures that are presenting a barrier to meeting the requirements and goals of the California RPS program.[36]

The Commission has invested time and effort in creating a streamlined form of contract for implementing Section 399.20, and should order the IOUs to continue using a similar PPA

[33] DRA Comments at 8-9.
[34] Id. at 9-10.
[35] Id. at 11.
[36] Cal. Stats. (2009), Chapter 328, section 1(b).

with the implementation of SB 32. FCE appreciates CalSEIA's sharing the German FIT contract – it informs the conversation regarding what terms are actually necessary in a streamlined FIT PPA.

SB 32 has revised some language in Section 399.20, and the Commission should authorize the IOUs to make limited modifications reflecting the statutory changes. FCE also encourages the Commission to consider standardizing the PPA. Currently there are differences in language (some substantive) between the SDG&E and SCE PPAs (which are similar to each other) and PG&E's Small Renewable Generator Power Purchase Agreement. These discrepancies are unjustified. Since it appears that PG&E's PPA would require less modification than the other IOUs' PPAs in order to be in conformity with Section 399.20 as modified by SB 32, the Commission could simply order all three utilities to use the PG&E Small Renewable Generator Power Purchase Agreement (with appropriate revisions) as a model. For the most part, FCE supports PG&E's proposed modifications to its PPA. FCE expressly supports the proposed revisions to PG&E's modified PPA and Schedule E-SRG filed today by Agricultural Energy Consumers Association ("AECA").

If the Commission adopts any additional limitations or requirements (e.g. an application fee) the requirement should be incorporated in simple, straightforward language.

B. Eligibility requirements need to be clear and consistent with Section 399.20.

FCE agrees with PG&E that the Commission needs to provide instruction to guide the IOUs in administration of the application process.[37] Establishing clear requirements that reflect the plain language in Section 399.20 will serve the interests of both applicants and the IOUs. SDG&E points out that "the ability to deny a FIT request on the first and third grounds [enumerated in Section 399.20(n)] should not be interpreted as an affirmative obligation on the

[37] PG&E Comments at 21.

part of the utility to "police" sellers in order to ensure compliance with § 399.20, other state and local laws, and/or applicable building standards."[38] FCE agrees and supports SDG&E's suggestion that the Commission allow sellers to warrant compliance with applicable standards.

C. Termination language should reflect statutory requirements.

PG&E suggests that both utilities and lenders need clarity regarding the parties' respective rights to terminate the PPA.[39] FCE agrees. The Commission should approve termination language that is straightforward and that is consistent with Section 399.20. As some parties have noted previously, certain termination language in the existing SCE and SDG&E PPAs is extremely ambiguous and problematic in the eyes of sellers and lenders.[40] The Commission can address this problem by adopting the PG&E form of PPA for SCE and SDG&E going forward or by ordering SCE and SDG&E to revise their PPAs to limit buyer termination language to terms consistent with Section 399.20.

D. Interconnection

The Commission should decline to adopt any requirement that sellers obtain deliverability status from CAISO as a prerequisite to participating in the expanded renewable feed-in tariff program.[41] Section 399.20(i) does not say anything about deliverability. It merely provides that the physical generating capacity of the facility "shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380." The Commission has recently initiated discussion of reforms to Rule 21 that are aimed at resolving the deliverability issue and other obstacles currently delaying the interconnection of DG facilities and inhibiting participation in the existing renewable feed-in tariff program.

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[38] SDG&E Comments at 19.
[39] PG&E Comments at 22.
[40] *See* SCE and SDG&E PPA § 4.2.
[41] SCE Comments at 15.

E. The Commission should provide clarification regarding dispute resolution.

FCE agrees with the Farm Bureau and Sierra Club that the Commission should provide guidance on dispute resolution.[42] Since the renewable FIT is designed for smaller sellers that may not have the resources to undertake costly litigation, the Commission's ADR program may be a useful alternative.

F. The Commission should adopt reasonable queue management requirements.

A number of parties make recommendations regarding the need for project development milestones. FCE supports such requirements. As discussed in previous filings, milestones and an on-line deadline are appropriate, as long as the expectations are appropriate for the technology and reasonable accommodations are made for public agencies.[43]

V. Procedural Recommendations

As discussed above, FCE supports the ALJ's initial proposal of a two-day workshop to discuss pricing proposals. FCE is already engaged in discussion with other stakeholders regarding pricing approaches and potential areas of agreement. The Commission should reschedule the workshop in the near future. In order to make the workshop an effective tool for exchange of ideas on pricing, FCE strongly urges the Commission to include in its ruling authorizing the workshop some initial guidance regarding the parameters for a pricing mechanism that is consistent with the plain language of Section 399.20 and PURPA. This guidance, together with an agenda that focuses discussion in the workshop on pricing approaches that conform to applicable requirements will appropriately narrow the discussion and facilitate productive dialogue.

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[42] Farm Bureau Comments at 7, Sierra Club Comments at 34.
[43] See FCE March 7, 2011 Brief at 24.

FCE is confident that the Commission can develop an appropriate pricing mechanism under Section 399.20 without holding evidentiary hearings. In other recent procurement-related proceedings the Commission has adopted a pricing mechanism for implementation of AB 1613 (the CHP feed-in tariff), various renewable auction mechanisms, and a complex negotiated QF pricing mechanism – all without requiring evidentiary hearings. It is in all parties' interest to develop a pricing mechanism that is simple and transparent as possible, while complying with applicable statutory and regulatory requirements. FCE is committed to helping the Commission accomplish this task.

VI. Conclusion

FCE appreciates this opportunity to provide further comments on issues related to implementation of SB 32. FCE looks forward to constructive discussion on key issues, including pricing and how to structure the program to encourage participation by a diversity of small DG resources.

Dated: August 26, 2011

Respectfully submitted,

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Attorneys for FuelCell Energy, Inc.

VERIFICATION

I am the attorney representing FuelCell Energy, Inc. (FCE) in this proceeding. FCE is absent from Sacramento County, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of FCE for that reason. I have read the attached *FUELCELL ENERGY, INC. REPLY COMMENTS TO SEC. 399.20 RULING OF JUNE 27, 2011*. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 26th day of August, 2011, at Sacramento, California.

Lynn Haug

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