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. 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 ("SB") 32 and SB 2 1X Amendments to Section 399.20 ("Ruling"), FuelCell Energy, Inc. ("FCE") submits the following comments on questions raised in the Ruling.[1] FCE appreciates the Commission's identification of SB 32 implementation as a priority in this proceeding, and the Commission's effort to seek broad stakeholder input on key issues. For the sake of clarity, FCE addresses the Commission's questions as they have been organized in the Ruling.

I. Introduction

The Ruling provides a well-reasoned framework for the expeditious implementation of the SB 32 and SB 2 1X amendments to Section 399.20. The Commission's ultimate goal should be the creation of a program that will operate efficiently and effectively and encourage the development of new, smaller scale, renewable distributed generation ("DG") facilities at optimal locations and from a diversity of resources. To satisfy this goal, program requirements and contracts need to be simple, clear and fair. Program administration must be transparent and streamlined to the extent possible. Pricing must meet all legal criteria, including the "indifference" requirement guaranteeing full payment for the unique benefits that small, optimally-sited, peaking, as-available and baseload resources provide to ratepayers.

In particular, FCE recommends that the Commission establish separate technology-specific prices for each type of eligible renewable resource. Although FCE does not believe that

[1] FCE manufactures, distributes and provides other services related to stationary fuel cells, including fuel cells fueled by renewable digester gas.

Section 399.20 mandates that the MPR, as currently calculated, be the starting point for SB 32 pricing, if the Commission chooses to use the MPR, the Commission also should find that technology-specific value-based adders must be included in SB 32 prices, to account for above-MPR environmental and locational benefits of DG, as mandated by the legislation.

FCE looks forward to actively participating in this proceeding and assisting the Commission in the successful implementation of SB 32 and SB 2 1X.

II. Procedural Issues

Before moving forward with the process of implementing SB 32, the Commission needs to resolve some procedural questions. The first issue, explicitly raised in the Ruling, is the question of delaying implementation of some contract terms and program requirements to a later phase of this proceeding. While well-intentioned, this approach is probably not workable. As discussed below in response to the Commission's questions, FCE prefers implementing SB 32 in one process, rather than trying to bifurcate the process. Since pricing and contract terms and conditions are a package in the eyes of customers, developers, and lenders, it really is not practical to implement them separately.

A second issue related to the timing of implementation has been raised, albeit informally, by the Clean Coalition, which asks the Commission to authorize projects larger than the current 1.5 MW limit to immediately begin signing contracts. This proposal should be promptly rejected. It would be disruptive and unfair to market participants that have acted in reliance on the Commission's prior rulings.

Lastly, FCE appreciates the ALJ's direction that pricing issues will be further discussed in a workshop setting. Given the disparate views on this subject, as discussed in interested parties' prior briefs, as well as some parties' view that the Commission does not even have the authority to set a renewable feed-in tariff price, FCE urges the ALJ to provide a clear agenda and as much guidance and facilitation as possible, in order to make the workshops a productive exercise.

III. Compliance with SB 2 1X

3.1 Definition of Market Price

1) ***Define market price of electricity as used in § 399.20. Is there one market price of electricity relevant to all types of electricity procurement or are there different market prices depending on the type of electricity that is being procured? For example, is there a unique market price of electricity for the market segment targeted in § 399.20? Does the market price of electricity include all types of electricity contracts and technologies that a utility procures or a subset of contracts and technologies? If you propose a subset, please define the subset.***

There is no one "market price" as used in section 399.20. In authorizing the Commission to establish a market price methodology, the statute acknowledges that prices paid for electricity by market participants reflect a variety of factors, including size, the length of contracts, long term ownership, operating and fuel costs, the value of different products (e.g., baseload, peaking, as-available), and the time of delivery. There is not a unique market price for the market segment targeted in section 399.20, as it authorizes purchases from a broad spectrum of renewable generators with unique and distinctive characteristics, applications, products and benefits. As discussed in FCE's March 2011 briefs, the Commission needs to set technology-specific prices for subsets of eligible technologies. Otherwise the program will pay too much for some resources (creating a "gold rush" to accept the SB 32 pricing) and too little for others (deterring their participation in the program), producing unbalanced and undesired results.

3.2 Continued Reliance on Market Price Referent

2) ***Explain whether the price for electricity purchased under § 399.20(d), as amended by SB 2 1X, must or should be based on the MPR as currently calculated.***

It is clear that there is more than one way the Commission can calculate a price for SB 32 resources. FCE does not interpret Section 399.20(d) as mandating that the MPR as currently calculated be the basis for SB 32 pricing.

3) ***Explain whether the price for electricity purchased under § 399.20(d) must or should be based on the MPR as currently calculated with the addition of new adders, as suggested by parties in the March 2011 briefs.***

To the extent that the MPR is used as the starting point for SB 32 pricing, it is imperative that the Commission make clear that the MPR is only the starting point for such pricing. SB 32 pricing based on the MPR would require that technology-specific value-based adders be added to reflect above-MPR environmental and locational benefits, as mandated by the legislation.

The MPR proxy plant is by definition a fossil fuel-fired generator. The MPR proxy plant is assumed to represent the marginal generator whose generation will be displaced by distributed renewable generation. The MPR contract price reflects only the costs of that fossil fuel-fired generator; it does not reflect any of the additional above-MPR value provided by distributed renewable generation. Therefore, to the extent that SB 32 pricing is derived using the MPR as the starting point, the base MPR must be increased through the addition of the technology-specific above-MPR values provided by distributed renewable generation.

4) ***Explain the benefits and the drawbacks of continuing to use the MPR as the basis of the price for the program under § 399.20 given the statutory changes.***

One of the benefits of using the MPR as the starting point for SB 32 pricing is that the MPR is a well-understood metric that is established through negotiation and intense scrutiny. The MPR calculates the required contract price to cover the costs of the 500 MW natural gas-fired combined cycle proxy plant for project on-line dates several years into the future. The specific components that make up the MPR can be identified with some effort in the MPR model from which the MPR values are derived. This ability to identify the values of the specific components of the MPR is an important stepping stone to ensuring that all technology-specific above-MPR adders added to the base MPR appropriately reflect the technology-specific value added.

The greatest weakness of the MPR for purposes of renewable energy pricing is that the MPR reflects the costs of a large, fossil fuel generator using a mature technology. As such, it does not capture any of the technology-specific value provided by smaller scale, distributed renewable generation. This weakness must be addressed if the MPR is to be used as the starting point for SB 32 pricing.

Another disadvantage to using the MPR is that one of its major components, the embedded natural gas fuel forecast, can quickly become out of date given natural gas price volatility. Although natural gas prices have been lower and more range-bound over the past several years due to the economic downturn and new production from shale gas, there is still significant uncertainty surrounding future natural gas prices. Depending on anticipated changes in natural gas prices, there may be some gaming with respect to timing of bringing projects online to take advantage of expected upward or downward changes in updated MPR values compared to then-current MPR values.

The natural gas price forecast issue was resolved for CHP pricing in the AB 1613 implementation by replacing the forecast embedded in the MPR with a monthly natural gas price index. This made sense for CHP pricing because many CHP projects are fueled with natural gas. Since SB 32 is specific to renewable generation, such a change would actually increase the level of uncertainty for renewable projects versus using the full MPR as a starting point.

If the existing MPR methodology is used as the starting point for SB 32 pricing, FCE stresses the need for a scheduled annual MPR update. FCE recommends that then-current MPR values and above-MPR adders be fixed at the time the SB 32 contract is executed, with the specific values for the life of the SB 32 contract locked in based on the project online date, as has been the practice in the past. Pricing certainty for the life of the SB 32 contract is a critical factor when seeking financing.

5) ***Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values. Consistent with CPUC decisions, Energy Division staff will calculate a 2011 MPR for the 2011 RPS Solicitation. Due to the statutory changes in SB 2 1X, it is not clear whether the Commission will continue to calculate an MPR to establish an RPS cost limitation. Parties should explain whether a new trigger for an MPR update is necessary and/or a schedule for how the MPR should be updated going forward.***

Any reliance on the MPR for purposes of SB 32 pricing would require the Commission to commit to a scheduled annual update of the MPR. An annual update would also ensure that the fixed and variable components of the MPR that underlie AB 1613 pricing reflect current MPR proxy plant costs. The scheduled annual update of the MPR should not be delayed based on RPS solicitation triggers or other SB 32 programmatic MW thresholds that might be established.

3.3 Additional Pricing Proposals

3.3.1 Technology-Specific Rates and Product-Specific Rates

6) ***Based on your definition of "market price of electricity," explain whether a technology-specific or product-specific proposal is a viable option for the § 399.20 program as updated by the SB 2 1X amendments.***

FCE supports the use of technology-specific rates for different types of renewable resources. Each type of renewable resource has a different value proposition with respect to environment (avoided emissions), location (ability to relieve congestion), and product provided (baseload, peaking, as-available). SB 32 pricing should appropriately compensate each eligible technology for the specific value proposition that it provides. Renewable technologies that are capable of cogenerating electricity and another useful product from waste heat should have a separate category of eligibility for electric-only and for cogeneration projects.

Product-specific rates for baseload, peaking, and as-available products can be differentiated by applying utility-specific time-of-delivery factors to the combined baseload MPR plus applicable above-MPR adders, or to any other all-in baseload price derived under SB 32. The physical quantity of avoided emissions should be based on the emissions of the underlying renewable technology compared to the average emissions of the California grid. The physical quantity of avoided emissions should be determined by the generating profile of each renewable technology, and thus does not need to have the time-of-delivery factor applied. In addition to being technology-specific, the physical quantity of avoided emissions should be valued at region-specific market prices to obtain the appropriate above-MPR adder for environmental attributes. Applying region-specific emissions allowance prices to a technology-specific physical quantity of avoided emissions will encourage renewable projects to locate in those regions of the state where avoided emissions have the most value.

FCE appreciates that different projects within a specific technology have different characteristics that would result in a project-specific value proposition. However, FCE believes that the resultant differences in pricing within a specific technology are unlikely to warrant the additional effort that would be required to derive project-specific prices.

7) Explain the specific methodology and all calculations and data that would be required to implement the technology or product-specific rate that you propose.

FCE continues to believe that the best foundational support for calculating a technology-specific rate for stationary fuel cells is the 2008 study issued by the National Fuel Cell Research Center at the University of California-Irvine, titled "Build-Up of Distributed Fuel Cell Value In California: Background and Methodology." ("UC-Irvine Fuel Cell Study" or "Study"). FCE described the methodology and results of the UC-Irvine Fuel Cell Study at some length it its March 2011 opening brief, and therefore limits its comments here to providing a specific example of how that methodology could be used to derive a region-specific value of avoided emissions, as recommended above.[2]

The UC-Irvine Fuel Cell Study calculates the value proposition of fuel cells by quantifying a number of distributed value elements, including avoided emissions and related health benefits. Then-current values for the MPR proxy plant are used in part to quantify the avoided costs of the electricity that distributed generation from fuel cells displaces. In this manner, the MPR is an integral component in determining the fuel cell value proposition. The methodology could be modified to incorporate avoided costs other than those associated with the MPR proxy plant to the extent the Commission determines that is appropriate.

The report described in CALSEIA's opening brief in this proceeding was prepared using the same methodology as the UC-Irvine Fuel Cell Study, changed as necessary to be applicable to rooftop solar photovoltaics ("PV") and presented in a different format designed to demonstrate its potential use for SB 32 pricing. The analysis underlying the CALSEIA report starts with the total solar PV value for each distributed value element and then strips out the MPR value (if any). The value proposition for solar PV is presented as the MPR plus the above-MPR value as a specific example of how SB 32 pricing could be derived using the MPR as a starting point. Utility- and region-specific results of the above-MPR values are presented on page 17 of CALSEIA's opening brief.

The case of avoided particulate matter less than 10 microns in diameter ("PM10") is used to provide an example of a specific calculation that was used to quantify the value of avoided emissions for both solar PV and fuel cells. Southern California Edison ("SCE") is chosen as the specific region for this example because the maximum market price for a PM10 emissions reduction credit ("ERC") of $300,000/pound/day has not changed since the time the CALSEIA analysis was done.

In the CALSEIA analysis, the avoided central station generator was assumed to be the 2009 MPR proxy plant, with a PM10 emissions rate of 0.057 pounds/MWh (grossed up to reflect avoided losses). All of these proxy plant PM10 emissions are avoided by rooftop solar PV, which produces no PM10 emissions. At the 2009 MPR proxy plant assumed load factor of 92% over a 25-year life, the $300,000/pound/day cost of a PM10 ERC was converted to an average

2 A 2011 Update to the UC-Irvine Fuel Cell Study is in its final stages of preparation by the National Fuel Cell Research Center at UC-Irvine and FCE hopes to include the 2011 Update as part of its reply comments in this proceeding. .

cost of 0.187 cents/kWh.[3] This compares to a statewide average PM10 ERC cost of 0.122 cents/kWh included in the 2009 MPR.

Taking the difference between the calculated PM10 ERC cost for the avoided MPR proxy plant of 0.187 cents/kWh and the average cost embedded in the 2009 MPR of 0.122 cents/kWh yielded an above-MPR value of 0.065 cents/kWh for avoided PM10 emissions attributable to rooftop solar PV within SCE's service territory. This 0.065 cents/kWh of solar PV value for avoided PM10 emissions is adjusted by SCE's TOD factors for solar PV's generation profile in SCE's service territory and is one component of the 5.279-11.460 cent/kWh above-MPR adder cited on page 17 of CALSEIA's opening brief. Above-MPR adders for other types of avoided emissions are derived in a similar manner. Note that no above-MPR adder was included in the CALSEIA study for avoided CO_2 emissions. With no market information available since California-specific market prices for CO_2 emissions allowances do not yet exist, the values for CO_2 emissions allowances prices embedded in the 2009 MPR were assumed to reflect the value of the avoided CO_2 emissions attributable to solar PV.

The PM10 emissions of fuel cells are negligible at 0.00001 pounds/kWh. Therefore, if all of the same assumptions were used to value the avoided PM10 emissions for fuel cells as were used in the CALSEIA study, fuel cells would have essentially the same value as solar PV in terms of the above-MPR value of avoided PM10 emissions. The above comparison emphasizes the need to conform all of the underlying assumptions and input values when evaluating the value proposition of different renewable technologies. This is true regardless of the specific form of technology-specific SB 32 pricing, i.e., whether the technology-specific value proposition is used to calculate above-MPR adders or some other SB 32 pricing formula.

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[3] Total PM10 ERC Cost = $300,000 /pound/day ERC cost times the average daily PM10 emissions. Average daily PM10 emissions = 0.057 pounds/MWh x average daily MWh generated. Average daily MWh generated = 500 MW x 92% x (8760 hours/year) / (365 days/year).

PM10 ERC Cost per kWh = Total PM10 ERC Cost divided by lifetime kWh generated. Lifetime kWh generated = Average daily MWh generated x (365 days/year) x 25 years.

8) ***If applicable, identify what specific subset of proxy plants is appropriate for the calculation. An example of a Commission-adopted methodology for calculating technology-specific costs would be the MPR model, which calculates the proxy costs of building and operating a Combined Cycle Gas Turbine (CCGT) facility.***

The use of the actual projects for the development of technology-specific MPR proxy plants would be acceptable to FCE as a pragmatic approach to move forward with full SB 32 implementation as expeditiously as possible. To the extent that the Commission decides to move forward with defining technology-specific avoided costs as suggested by the FERC Order on Rehearing, FCE recommends that a Working Group representing each technology put forward a proposed avoided cost representative of that technology. As explained above, renewable technologies capable of cogeneration should have a separate category of eligibility for electric-only and for cogeneration projects to ensure that the value of cogeneration is fully compensated.

3.3.2 Market-Based Rate

9) ***Do you support this [competitive auction] approach? Please explain. Discuss whether and how this approach is consistent with the provisions in § 399.20(f). Also explain the mechanisms of how a competitive auction would be used to determine the price (e.g., are projects paid as bid, paid the market clearing price, or paid another price point determined through an auction), and how, if at all, the auction would differ from the design of the Renewable Auction Mechanism in D.10-12-048.***

FCE does not support SCE's suggestion to determine the price under § 399.20 by competitive auction.[4] An auction would violate Section 399.20(f), which requires the IOUs to make the SB 32 tariff available to all eligible electric generation facilities upon request and on a first-come-first-served basis. SCE itself acknowledged in its March 2011 brief that altering this fundamental aspect of SB 32 would require action by the California Legislature.[5] For this reason alone, the Commission need not devote any additional time or resources to considering SCE's proposal.

SCE's brief was very clear that the auction proposal was premised entirely on its theory that the Commission could not legally set a feed-in tariff price. FERC has definitively rejected that argument, most recently in the Order Denying Rehearing issued January 20, 2011, mooting

[4] SCE's March 2011 opening brief argued that the Commission was preempted from setting prices for a renewable feed-in tariff, and on the basis of this argument, recommended that the Commission use the existing RAM program to implement SB 32.

[5] *See* SCE March 7, 2011 brief at 7 ("SCE recommends the Commission explore an SB 32 amendment with the legislature to allow for such an [auction] approach.")

the justification for SCE's proposal. The Commission has already authorized, and the IOUs have implemented, a variety of auctions and solicitation processes for renewable resources. Renewable generators that qualify for RPS auctions already have a place to go. The renewable feed-in tariff authorized by AB 1969 and SB 32 was designed to provide a streamlined process for a different class of market participants. These smaller generators – because of their size, technology, or project characteristics -- cannot compete in the auction processes available to larger, more established and well financed market participants. Turning the renewable FIT into an auction would completely undermine the purpose of SB 32.

3.3.3 Rate Based on Power Purchase Agreements

10) Given that a significant number of RPS solicitations have occurred since this time, using your definition of the market price of electricity, explain whether a rate under § 399.20(d) should be based on RPS power purchase agreement prices. Parties supporting this methodology should identify what subset of power purchase agreements is appropriate for the calculation, whether the price should be the weighted average of PPA prices or recommendations and calculations, where appropriate and necessary to implement such a methodology. Lastly, parties should articulate if there should be one rate or multiple rates. If parties suggest multiple rates, parties should define what the multiple rates should be and how they should be derived.

From the perspective of customers interested in developing fuel cell projects, basing prices for SB 32 on RPS contracts appears to be unworkable. The economics and market position of digester gas projects generally, and renewable fuel cell projects specifically, have effectively precluded their participation in all-source RPS solicitations. Notwithstanding the state's interest in encouraging digester gas projects, and the unique benefits that such projects provide, digester gas projects have not found a place in the existing solicitation processes. Therefore, the fact that the Commission has overseen "a significant number of RPS solicitations" simply has no relevance in determining an appropriate price for fuel cell projects fueled by biogas. For all the reasons discussed above and in FCE's March briefs, using RPS prices from PPAs with large solar projects or other technologies having different costs, benefits and project attributes would likely result in excluding fuel cells using on-site biogas from participation.

Leaving aside the lack of relevant RPS pricing data for fuel cells, there is also at least one other very important reason that using PPA prices from the RPS would be impractical across the board - the lack of transparency. Under the Commission's confidentiality rules, key information from the RPS is not available to market participants. Without access to project-specific prices *and* project characteristics *and* negotiated terms and conditions, there is no way market participants can make an informed discussion regarding the use of RPS prices as a reference point for SB 32 contracts. It would seem virtually impossible to ascertain, given the lack of publicly available information, whether the RPS-based price was consistent with SB 32 statutory requirements and whether the RPS contract terms are comparable. For these reasons, RPS contracts do not appear to be a viable basis for SB 32 project pricing.

11) Provide all relevant details for other alternate pricing proposals, if any, consistent with the provisions of SB 2 1X.

FCE has no additional comments to make at this time regarding alternative pricing proposals.

3.4 Additional Pricing Questions

12) Identify relevant data sources that could be used to implement any proposed methodology and whether the data used to calculate the rate should be derived from public or confidential data. Please comment on the appropriateness of the data sources as identified by parties in opening comments, such as Fuel Cell Energy and CALSEIA.

As discussed above, FCE continues to support using the UC Irvine Fuel Cell Study as the basis for data for setting prices for fuel cell projects.[6] FCE is open to consideration of additional sources of relevant input data, including information that may be available from existing digester gas and fuel cell projects.

13) Explain how often the price under § 399.20(d) should be calculated given your preferred price calculation approach. The price may be calculated once, at regular intervals, such as annually, or in response to a triggering event. For example, in March 2011 briefs, CALSEIA proposed that the price be modified quarterly and be increased or decreased based on market participation. The California Solar Initiative presented a different model for reducing prices over time in which incentive rates decline over the life of the program in multiple steps triggered by solar capacity additions to facilitate market transformation.

FCE conceptually supports periodic review and updating, as necessary, of technology-specific prices. Such updates may be performed with a scheduled periodicity or triggered by

[6] *See* FCE March 7, 2011 brief at 15, fn. 21.

program subscription milestones. Regardless of the approach taken to updating program prices, the Commission should also retain and exercise its discretion as necessary to adjust prices downward or upward within each technology-specific price category in response to unanticipated developments (e.g. lack of market response or oversubscription) in the program. The applicable program price should be fixed for the life of the contract based on contract execution date and project online date.

FCE is not opposed to CALSEIA's proposal for quarterly review of market response to PV prices. A less frequent review would probably suffice for fuel cell prices (coupled with a discretionary "step in" by the Commission as needed to correct prices in response to a "gold rush" if prices exceed reasonable levels or if the opposite occurs), given the longer lead time required to develop digester gas projects and the fact that the fuel cell market is smaller in number of participants and projects, and less mature than the market for solar PV applications.

3.5 Ratepayer Indifference

14) Respond to these [stakeholder and CPUC] interpretations of "ratepayer indifference" and explain how the SB 2 1X amendments to §399.20(d) and any new pricing proposal that you suggest pursuant to these amendments impact these interpretations.

In construing the meaning of "customer indifference" the Commission need not look beyond the plain meaning of the words. Indifference, by definition, means that sellers should be fully compensated, but not overcompensated for the value of the resource. FCE supports the Commission's recognition, in Decision 09-12-042, that the indifference standard dictates that the price paid for power must reflect the specific attributes of the resource, and the value of those attributes to all other customers.[7] This principle is fundamental to FCE's recommended approach to pricing.

3.6 FERC Order 134 FERC ¶ 61,044 – Order Denying Rehearing

15) Please indicate how those positions [in March 2011 briefs] have changed, if at all.

The statutory amendments in SB 2 1X do not alter FCE's position on the impact of federal law. As discussed in FCE's March 7, 2011 brief, the Order Denying Rehearing provides useful guidance for establishment of avoided cost prices that are consistent with PURPA. FERC

[7] D.09-12-042 at 17

reiterated in the Order Denying Rehearing that "a *state* may determine what particular capacity is being avoided" and that "the state may rely on the cost of such avoided capacity to determine the avoided cost rate."[8] And FERC helpfully clarified that "the avoided cost rate may take into account the cost of electric energy from the generators being avoided, *e.g. generators with certain characteristics*."[9]

The characteristics in question, for purposes of implementing SB 32 and SB 2 1X, are generators that meet the statutory definition of eligible renewable energy resources and other statutory criteria, e.g. size. There is nothing in the Order Denying Rehearing suggesting that the Commission may not categorize the "generators being avoided, e.g. generators with particular characteristics" by technology or other relevant criteria. And there is nothing preventing the Commission from setting avoided cost prices that are specific to each resource category.

As the Ruling notes, SB 2 1X moved the language authorizing the Commission to establish a methodology for determining the market price of electricity from Public Utilities Code section 399.15 to section 399.20. That methodology mandates consideration of enumerated criteria, which include long term IOU fixed price contract prices, costs associated with new generating facilities, and the value of different electricity products. The price must include current and anticipated environmental compliance costs, and the Commission is authorized to adjust rates to reflect time of delivery, and is obligated to ensure ratepayer indifference.[10] FCE stated in its March briefs and continues to believe that the Commission can establish a price that is consistent with relevant FERC orders construing PURPA *and* the criteria set forth in section 399.20.

IV. Compliance with SB 32

16) Parties are requested to comment on this proposal [to implement identified issues in 2011 and others in 2012].

FCE understands and appreciates the Commission's desire to move forward quickly with implementation of SB 32. However, as a number of parties pointed out at the July 11 prehearing conference, many of the program elements are interrelated. In FCE's experience, customers carefully consider price *and* all other terms and conditions before making a decision to initiate

[8] 134 FERC ¶ 61,044 at paragraph 30 (emphasis in original).
[9] Id. (emphasis added).
[10] Pub. Ut. Code § 399.20(d).

project development. For this reason, and in order to avoid unintended confusion and controversy, it is preferable to address all issues in one coherent process. One issue – ensuring expeditious interconnection – obviously will require a degree of coordination with Commission efforts underway in other proceedings. However, such coordination does not necessitate delay. Indeed, the fact that the Commission is already working to address DG interconnection issues should be helpful.

Lastly, FCE reminds the Commission of the proposal by several parties to allocate 20 percent of program capacity for digester gas projects. If the Commission agrees that such an allocation is justified it needs to be implemented from the outset.

4.1 Increase Size of Eligible Facility to 3 MW

17) Explain any further issues to be considered on capacity limitation under this program and next steps necessary to implement the provision. To implement § 399.20(b)(2), tariff language and form contracts may need to be amended. The investor owned utilities should submit tariff changes or revised contract language, if any, to implement this change with comments on July 21, 2011 and July 28, 2011.

In its March briefs FCE discussed its support for increasing the size to 3 MW for fuel cell and other biogas facilities. FCE also indicated that it supports CalSEIA's recommendation regarding the phase-in for small solar PV.[11] These positions are unchanged, and FCE is not aware of any additional issues to be considered at this time.

4.2 Proportionate Share and Increased Program Cap to 750 MW

18) Explain the drawbacks and benefits to relying on the existing methodology for calculation of proportionate share. Does the statute require a recalculation of proportionate share based on the addition of publicly owned utilities? Would the Commission's calculation of proportionate share for local publicly owned utilities be restricted by any jurisdictional limitations?

FCE has no additional comments on the proportionate share methodology. Since the Commission does not have jurisdiction over local publicly owned utilities, the Commission's calculation must, of necessity, be based on its best estimation of local publicly owned utilities' share of the 750 MW program.

[11] FCE Reply Brief at 4.

FCE notes that two additional questions arise with respect to the program cap. First, as noted above, the Commission needs to make a determination on the proposal for setting aside a portion of each of the three large IOUs' program for digester gas projects. For the reasons discussed in FCE's March 2011 briefs (and the briefs of other parties advocating a similar set aside), FCE urges the Commission to adopt a 20 percent allocation for digester gas projects.

The second question that requires clarification is how to account for the capacity associated with projects that drop out of the program after signing a contract or otherwise fail to initiate commercial operations, or that amend the PPA to decrease project size. In order to effectuate the intent of the Legislature, the unused program capacity associated with such projects should be added back into the IOU's total available MW allocation, subject to any relevant sub-allocation (e.g. drop-out biogas project MWs should go back into the biogas allocation, assuming the Commission adopts the biogas set aside proposal). In order to avoid uncertainty, the Commission should provide specific instructions on how to administer this process.

4.3 Separate Tariffs

19) This ruling proposes to implement this provision by end of 2011. Explain the next steps necessary to implement this request.

The ALJ has instructed the IOUs to file draft tariffs and contracts on August 5, 2011. The IOUs should (and presumably will) start with the existing renewable FIT contract and revise it to add language reflecting the new statutory requirements established in SB 32. Other parties will comment on the draft contract in reply comments. FCE is hopeful that, consistent with the purpose of the FIT, the final contracts will be as simple and streamlined as possible, consistent with statutory mandates.

4.4 Retail Customer Requirements Eliminated

20) Explain the next steps necessary to implement this provision, what modification to tariffs are needed to reflect this change, and what changes to the form contract might be required.

References to "customer" in the tariffs and contracts should be removed and the appropriate language tracking section 399.20(b) added to the "applicability" section of the tariff and contract.

4.5 Yearly Inspection and Maintenance Report

21) Parties are asked to comment on this recommendation.

For the reasons discussed above, FCE recommends not deferring implementation of this requirement. As discussed in FCE's March briefs, the inspection and maintenance reporting requirement should be bi-annual, simple and straightforward.

4.6 10-day Reporting Requirement of Request for Service under Tariff

22) Parties are asked to comment on this recommendation.

FCE supports implementing this requirement in 2011 and has no additional comments at this time.

4.7 Publicly owned electric utilities

23) Identify any issues and explain why coordination would be helpful. Identify any potential matters that the Commission may address relative to § 399.20 that may impact the implementation of § 387.6. One issue already identified in March 2011 briefs is the calculation of proportionate share of the 750 MW program cap.

FCE has no additional comments on this question.

4.8 Utility Discretion to Deny Tariff

24) Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

With respect to the timing of implementation, this task should not be delayed. In order for prospective customers and financing entities to have a clear understanding of all program requirements, and to prevent unnecessary disputes, it is critical that the Commission establish guidelines for the exercise of utility discretion from the outset.

4.9 Tariff or Contract Termination Provisions

25) Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.

Contract termination provisions are an essential condition of the PPA. The Commission should not delay implementation of SB 32, which provides clear direction regarding this key aspect of the FIT contract. Implementing this standard term will eliminate perceived risk, the presence of which can make it difficult for sellers to obtain project financing.[12]

4.10 4.10 Expedited Interconnection Procedures

26) Parties are asked to comment on this recommendation.

FCE supports making expedited interconnection procedures a priority in implementing SB 32. As a number of parties pointed out in briefs and at the recent prehearing conference, interconnection of small DG facilities has become increasingly difficult. FCE understands that ensuring expedited interconnection under SB 32 cannot be accomplished in a vacuum. However, implementing section 399.20(e) need not and should not be delayed until all of the larger issues surrounding distribution voltage interconnections are solved.

4.11 Adjustments for Small Electric Utilities

27) Parties are asked to comment on this recommendation.

FCE supports the Ruling's recommendation to create an exemption for small electric utilities.

4.12 Refunds of Other Incentives

28) Parties are asked to comment on this recommendation.

FCE does not support the recommendation to delay implementation of section 399.20(k). For many eligible generators, the decision whether or not to sign a renewable FIT contract will depend on how the Commission implements this provision of SB 32. FCE has provided additional comments on this issue in its March briefs. FCE adds here that regardless of the eligibility conditions adopted for projects that have previously received incentives, the Commission should make it clear that a customer with an existing CSI or SGIP project at a particular location is not barred from signing a PPA for any separate, additional generation facility located at the same site.

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[12] As noted in FCE's March 7, 2011 Brief, the termination provisions of the FIT contracts are currently not standardized between the IOUs. *See* FCE Brief at 9-10.

V. Conclusion

FCE appreciates the opportunity to provide its views on the most effective and efficient means of implementing the amendments to section 399.20 in SB 32 and SB 2 1X and looks forward to actively participating in the workshops on pricing issues.

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Respectfully submitted,

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