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)

CLEAN COALITION REPLY COMMENTS ON

ALJ RULING

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August 26, 2011

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The Clean Coalition respectfully submits these reply comments on the Administrative Law Judge's Ruling dated June 27, 2011. The Administrative Law Judge granted an extension for reply comments in his July 15, 2011, ruling (Rule 11.6).

The Clean Coalition is a California-based policy organization, part of Natural Capitalism Solutions, a non-profit entity based in Colorado. The Clean Coalition focuses on policies that deliver cost-effective and timely clean energy, including within the underserved "wholesale distributed generation" (WDG) market segment, which is comprised of wholesale generation projects interconnected to the distribution grid. WDG is a particular focus given the combination of cost-effective energy and economic benefits that it delivers, while at the same time avoiding all of the challenges associated with transmission build-outs. The Clean Coalition is active in proceedings at the California Public Utilities Commission, California Air Resources Board, California Energy Commission, the California Legislature, US Congress, the Federal Energy Regulatory Commission, and in various local governments around California.

Our main points are as follows:

General Points

- The Clean Coalition recommends that the Commission utilize the following guiding principles on optimal feed-in tariff/CLEAN design: transparency, longevity, and certainty. These are the features that create best-in class feed-in tariffs, according to Deutsche Bank's well-known ranking of FITs around the world.
- The utilities' proposed PPAs are not sufficiently transparent or certain because of their tremendous complexity. Paperwork burdens can be deal killers and we fear that the immense burden of paperwork that the utilities seek to impose on SB 32 sellers will make the program unattractive to all but the largest and best-

financed companies. Currently, pricing and interconnection problems are the main barriers to wholesale DG, but if the proposed tariffs and PPAs are approved by the Commission, it is likely that the paperwork burden will become the main barrier. The Clean Coalition wishes to see a democratized energy grid, in which numerous parties, large and small, can take part with minimal burdens.

Proposed Tariffs and PPAs

- We have recommended numerous changes to the proposed PPAs and tariffs in order to achieve a more streamlined and less burdensome path forward. Some of the more prominent recommendations, which apply to all PPAs and tariffs, include:
  - It is imperative that tariffs and PPAs specify that MW limits are AC, not DC. AC reflects the actual power sent to the grid, whereas the DC rating reflects the power produced before various losses are considered
  - Full capacity deliverability should <u>not</u> be required of SB 32 projects. We have argued this issue in the RAM proceeding and it applies even more forcefully for SB 32 because these projects will be far smaller and at greater risk of becoming financially unviable due to unwarranted requirements. Seeking deliverability should be a developer/Seller choice, not a requirement
  - The Clean Coalition recommends that an application fee (not currently part of any of the proposed tariffs) of $2/kW be required in addition to the development security requirement. The application fee should be refunded if the project is not accepted into the SB 32 queue (which is the position the applicant will receive once the application is deemed complete). The fee paid will roll over into the development security if the project remains in the queue.
  - Utilities should be required to provide a response to applicants within 10 business days with respect to the completeness (or lack thereof) of the SB 32 application. Applicants should be given 10 business days to cure any

defects and the utility should then be given an additional 5 business days to inform the applicant of a successful cure (or lack thereof).

- Pricing of the SB 32 PPA should be locked when the queue position is granted – not when the date a project comes online, as discussed further below.
- Applicants should have 18 months from confirmation by the utility of the applicant's queue position to complete construction of the project, with one six-month extension allowed for events outside of the control of the applicant (as with the RAM program).
- In addition to the application fee as an initial hurdle to ensure only serious developers apply for what is a fairly modestly-sized feed-in tariff/CLEAN program, we recommend that applicants be required to submit an interconnection application to the utility or CAISO, under the Fast Track or ISP procedures, within one month of receiving the SB 32 queue position, or apply to the next cluster study window. If the applicant fails to meet this milestone, it will lose its queue position. We do not agree with the utilities' suggestion that a completed Phase 1 study or interconnection agreement should be required before an application to the SB 32 program may be submitted – this is an overly high hurdle that will prevent many eligible parties from participating.
- Once the utility verifies the interconnection application is submitted, the SB 32 PPA should be executed.
- We agree with the utilities that a development security of $20/kW should be required, but we recommend that this security be required within 30 days of receipt of a Phase 1 interconnection study (cluster), or System Impact Study (ISP or Rule 21), or successful Fast Track initial review.
- We agree with the utilities that a penalty of 1% per day of the development security should be assessed for late projects, up to a maximum of 180 days beyond the Commercial Operation Deadline (COD).

- The utilities argue that they should have discretion to deny SB 32 PPAs in a number of circumstances, and they include specific language in their proposed tariffs for doing so. The Clean Coalition disagrees with the IOU interpretations of SB 32 in that it seems clear to us that the language from SB 32 included in the tariffs (P.U. Code section 399.20(n)) should not be interpreted to provide any additional authority to the utilities on the issues discussed; rather, SB 32 should be interpreted as guidance with respect to other existing programs and procedures for SB 32 projects, such as the existing interconnection procedures that ensure that any renewable energy project seeking interconnection to the grid will not lead to grid instability

- PG&E proposes that the Commission should impose a sunset date for the SB 32 program, and that if the IOUs have executed sufficient volume of RPS-eligible PPAs to ensure they can satisfy their RPS requirements, then that IOU would no longer be required to offer a tariff under SB 32. The Commission should clarify that the tariff must remain available until each IOU has fulfilled its proportion of the 750 MW program size, and that the RPS requirements are a floor and not a ceiling for renewable energy procurement.
- SDG&E's request to limit FIT project size to 1.5 MW should be denied for lack of evidence. The Clean Coalition agrees with Vote Solar that SDG&E has made no showing that a limit of 1.5 MW is necessary "to maintain system reliability," as is required for the PUC to exercise its discretion under SB 32
- Section 399.20(m) requires electric corporations to post a copy of each FIT request on its Internet website within 10 days of receipt of such request. SDG&E proposes that a "request" be defined as the execution of tariff contract. Category VIII(A) of the Confidentiality Matrix adopted in D.06-06-066, et seq., treats bid data as confidential until contracts are submitted to the Commission. But in contrast to SDG&E's assertion, FIT participation requests are not bids, because a FIT is by definition a set price. "Request" should be given its plain meaning.

Pricing Issues

- We reiterate our recommendation for using TACs as a simple proxy for initial implementation of a Locational Benefits price adder

- The Clean Coalition agrees with parties, including IREC and Sierra Club, that the Commission should require that a generator apply for or obtain QF status, and determine that whichever pricing methodology is proposed is an "avoided cost" pursuant to PURPA. Doing so will bring the Commission's decision into compliance with FERC, enhancing legal certainty with respect to pricing.

Deliverability Issues

- We reiterate our opposition to the IOUs' request for full capacity deliverability because this should be a choice, not a requirement. This concern is even more relevant to SB 32 than to RAM because SB 32 projects are generally far smaller, and thus more on the edge financially, than RAM projects.

Rate-basing Distribution Grid Upgrades

- We support IREC's proposal to waive/rate-base distribution grid upgrade costs when a project's capacity is less than 100% of minimum load on a distribution feeder, but we recommend also that the utilities be required to provide line section data on their interconnection maps so that developers can easily see which lines will qualify for the waiver.

Federal Preemption Issues

- SCE is incorrect in arguing that the Commission cannot set a feed-in tariff price under SB 32 based on the MPR. FERC has made clear that states have broad latitude to set avoided costs, particularly when state law requires a particular type of energy procurement, as is the case with SB 32's 3 MW size limit carveout. Under FERC precedent, the Commission has clear authority to set a specific avoided cost for 3 MW and smaller renewable energy projects.

I. General comments

Deutsche Bank (DB) has released numerous reports on feed-in tariff policy and best practices.[1] They have suggested that successful programs are those that provide transparency, longevity and certainty (TLC). DB describes in their most recent FIT report how Germany has achieved the "best-in class" FIT because of its smart design and proven results (p. 3):

> Through our global analysis of international climate and energy policy, we have singled out Germany's feed-in tariff (FIT) for renewable electricity as 'best-in class' for minimizing investor risk and cost-effectively scaling up renewable generation. Germany's advanced feed-in tariff maximizes investor transparency, longevity and certainty (TLC) while charting a pathway to grid parity within an overall cost/benefit framework.

We recommend that the Commission use these as guiding principles in its implementation of SB 32.

II. Proposed tariffs

The utilities' proposed tariffs and PPAs are highly problematic for a number of reasons. They are neither transparent nor certain because of their tremendous complexity. The proposed PPAs, in particular, seek to impose a crushing amount of paperwork and other requirements on SB 32 sellers. The legal burden alone, in reviewing and complying with these proposed PPAs, would be prohibitively expensive for many parties. These requirements will very likely make the program as ineffective as the AB 1969 program has been unless the Commission is proactive and requires many substantial changes before approving these proposed documents. SCE, in particular, seeks to impose a far wider array of reporting requirements and seeks proprietary information from Sellers than is unwarranted.

[1] The most recent in 2011: http://www.dbcca.com/dbcca/EN/_media/German_FIT_for_PV.pdf.

We have recommended numerous changes to the proposed PPAs and tariffs in order to achieve a more streamlined and less burdensome path forward. Some of the more prominent recommendations, which apply to all PPAs and tariffs, include:

- It is imperative that tariffs and PPAs specify that MW limits are AC, not DC. AC reflects the actual power sent to the grid, whereas the DC rating reflects the power produced before various losses are considered
- Full capacity deliverability should <u>not</u> be required of SB 32 projects. We have argued this issue in the RAM proceeding and it applies even more forcefully for SB 32 because these projects will be far smaller and at greater risk of becoming financially unviable due to unwarranted requirements. Seeking deliverability should be a developer/Seller choice, not a requirement
- The Clean Coalition recommends that an application fee (not currently part of any of the proposed tariffs) of $2/kW be required in addition to the development security requirement. The application fee should be refunded if the project is not accepted into the SB 32 queue (which is the position the applicant will receive once the application is deemed complete). The fee paid will roll over into the development security if the project remains in the queue.
- Utilities should be required to provide a response to applicants within 10 business days with respect to the completeness (or lack thereof) of the SB 32 application. Applicants should be given 10 business days to cure any defects and the utility should then be given an additional 5 business days to inform the applicant of a successful cure (or lack thereof).
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- Applicants should have 18 months from confirmation by the utility of the applicant's queue position to complete construction of the project, with one six-month extension allowed for events outside of the control of the applicant (as with the RAM program).
- In addition to the application fee as an initial hurdle to ensure only serious developers apply for what is a fairly modestly-sized feed-in tariff/CLEAN

program, we recommend that applicants be required to submit an interconnection application to the utility or CAISO, under the Fast Track or ISP procedures, within one month of receiving the SB 32 queue position, or apply to the next cluster study window. If the applicant fails to meet this milestone, it will lose its queue position. We do not agree with the utilities' suggestion that a completed Phase 1 study or interconnection agreement should be required before an application to the SB 32 program may be submitted – this is an overly high hurdle that will prevent many eligible parties from participating.

- Once the utility verifies the interconnection application is submitted, the SB 32 PPA should be executed.
- We agree with the utilities that a development security of $20/kW should be required, but we recommend that this security be required within 30 days of receipt of a Phase 1 interconnection study (cluster), or System Impact Study (ISP or Rule 21), or successful Fast Track initial review.
- We agree with the utilities that a penalty of 1% per day of the development security should be assessed for late projects, up to a maximum of 180 days beyond the Commercial Operation Deadline (COD).

SCE's proposed tariff

SCE has proposed a new pricing mechanism ("MP FiT") with its tariff and PPA submission. We comment on this mechanism and other issues in Section III below, along with other party recommendations with respect to price.

As a general matter, we note that CREST projects in SCE's queue should be unaffected by SB 32 unless they wish to relinquish their CREST queue position and seek an SB 32 contract. If developers have signed a CREST PPA they should be bound by that PPA and not be able to seek an SB 32 contract for the same project unless they first terminate the CREST PPA. CREST developers that have not signed a PPA, but are in SCE's queue, should be given preference for seeking an SB 32 contract, based on queue position.

SCE should clarify its tariff statement with respect to participation by SB 32 customers in other programs (sheet 2), making it more clear that participants are not precluded from an SB 32 contract merely due to the fact they have a CSI or SGIP project already on-site. As is, the language could too easily be interpreted as preventing multiple projects. We suggest that SCE make it more clear that a "Facility" may not receive an SB 32 contract in addition to other program incentives, but that a "participant" is not precluded from an SB 32 contract for a different facility on the same property as a CSI or SGIP project.

SCE's Sheet 3 requires that applicants have a completed Phase 1 study or its equivalent, as well as a deliverability study:

> a. Eligible Electric Generation Facility – A generation facility that meets all of the following criteria:
> (1) Has a contract capacity of not more than 3.0 MW and is located within SCE's service territory.
> (2) Has a completed Phase 1 interconnection study or its equivalent, including a deliverability study.

The Clean Coalition strongly disagrees with these proposed requirements. If a developer wishes to take the risk of committing to a PPA without having a completed study it should have the right to make such a choice. Rather than require a completed Phase 1 study, we recommend that parties be required to submit an application fee and, no more than 30 days after receiving an SB 32 queue position, submit an interconnection application to the host utility or CAISO under ISP, Fast Track or Rule 21, or submit a cluster application into the next available cluster window. Failure to do so would cause the developer to lose its SB 32 queue position. We believe that requiring a Phase 1 study, by itself, is too high a hurdle for SB 32 and is not required by law, let alone a deliverability study.

Even though the new SB 32 program will be relatively modest in size, our recommendations are designed for an optimally-designed larger program because it is our hope that the Commission will use its inherent authority to expand the SB 32 program beyond the 750 MW initial tranche, if experience warrants such an expansion. As a potentially longer-term and larger program, we believe that the desire for increased democratization of energy production weighs heavily in favor of requiring neither a Phase

1 study or a deliverability study upon application. Completing a Phase 1 study will cost at least $50,000 in the case of the cluster process or ISP (much less for Fast Track but the vast majority of projects will not qualify for Fast Track). This is a very heavy hurdle for many potential applicants who wish to explore the potential for SB 32 projects on their rooftops or open space without committing very substantial funds and a lot of time. Our recommendation of a $2/kW application fee, refundable if the application is rejected by the utility, presents the appropriate balance between filtering out unserious applicants and an overly stringent application process like that proposed by the utilities. Under our proposal, a party may submit an SB 32 application for up to $6,000 (for a 3 MW project), find out from the utility if it meets the requirements, receive a queue position, and only then be required to submit an interconnection application – which may be far more expensive than the initial application fee. If the applicant decides not to pursue the interconnection study within 30 days of receiving its SB 32 queue position (or by the next cluster study window), it will lose its SB 32 queue position and that reserved capacity will go back into the available pool for other applicants

A potentially larger problem with SCE's proposed tariff is in the very next section, in which SCE requires applicants to develop only those projects identified in SCE's interconnection map as preferred locations:

> (3) [Eligible projects] Will interconnect at one of the preferred locations as identified on SCE's circuit map posted on its website; provided, however, that this provision shall not apply to generation facilities that, as August 5, 2011, had already submitted an interconnection application or were already interconnected.

The Clean Coalition strongly recommends that this requirement be eliminated. SCE's map, as the Commission has pointed out in its draft resolution E-4144 on the utility RAM advice letters, is not in compliance with the RAM decision. Moreover, it is entirely unclear what SCE's map depicts, in terms of an advantage for applicants, because the map is so sparse in its details that a developer can gain literally no information about the interconnection benefits of the areas identified by SCE in its map.

Moreover, it is bad policy to allow a black or white, "all or nothing," approach to determining good locations for SB 32 projects. Let the market decide through appropriate pricing for SB 32 projects – as we have suggested in our opening comments with our locational benefits pricing adder.

SCE also seeks to impose additional hurdles on SB 32 projects in its tariff that will be dealt with in interconnection studies, making any reference in the tariff redundant and potentially harmful. Specifically, SCE seeks to be able to reject applicants if:

> b. The transmission or distribution grid that would serve as the point of interconnection is inadequate.

We understand that this language derives from SB 32 itself, but this statement does not belong in this tariff. Rather, literally all interconnection issues will be resolved through interconnection studies <u>that have no relation to the SB 32 tariff</u>. A party may apply for interconnection and have no intent to utilize the SB 32 tariff because it wishes to sell into a different program or a different utility. As such, there is no good rationale for SCE to seek the authority to deny applicants based on what are unspecified and potentially arbitrary additional procedures suggested in SCE's proposed tariff. SB 32 does provide the authority to utilities to deny service based on this criterion, <u>but this authority should not be stated in the tariff as though it is an authority that exists over and above the normal interconnection study procedures, which in themselves provide the checks and balances SB 32 seeks to ensure with this language</u>. The Commission should be proactive in interpreting SB 32's language in this regard in such a way that makes the most sense given the lay of the land with respect to current interconnection procedures, the desire for a streamlined feed-in tariff, and fairness to applicants who need maximum transparency in this new program.

The next two sections in SCE's proposed tariff should be struck under the same rationale:

> c. The generation facility does not meet all applicable state and local laws and building standards and utility interconnection requirements.

d. The aggregate of all generation facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.

SCE also requests authority to deny an SB 32 applicant if: "e. A previously executed MP FiT PPA with the generation facility was prematurely terminated." The Clean Coalition is not necessarily opposed to this provision, but it needs more detail to avoid the potential for abuse by SCE with respect to applicants who had legitimate reasons for termination.

SCE also seeks to require interconnection of SB 32 projects exclusively under WDAT or CAISO procedures (Special Condition 5). <u>This is unwarranted and would constitute bad policy</u>. The Commission is currently considering Rule 21 reforms in the newly-convened Rule 21 Working Group, which has recently been transformed into a settlement proceeding with a target end date of the end of the year. However, the Clean Coalition has recommended previously, and will continue to recommend, that the Commission assert its jurisdiction over all wholesale distributed generation interconnection insofar as such jurisdiction is not preempted by federal law. This is a complex issue but it is very clear, and uncontested, that the Commission has jurisdiction over interconnection of Qualifying Facilities when such facilities sell all of their output to the host utility. As such, many SB 32 projects could certify as QFs and be eligible for interconnection under the existing or revised Rule 21. Rule 21 is currently used – electively – by SCE to interconnect AB 1969 FIT projects. There are numerous problems with using Rule 21 in this program, but these issues are being addressed in the Rule 21 Working Group. Accordingly, the Commission should strike SCE's suggested requirement for WDAT or CAISO interconnection procedures.

SCE's Special Condition 7 is also problematic insofar as it suggests that SCE's obligation to enter into SB 32 PPAs will end when it meets its 33 percent RPS requirement. SB 32 is, to the contrary, a stand-alone law and there is no requirement that it be suspended if and when SB 2 (1x)'s 33 percent requirement is met. The reference in SB 32 to section 399.15 (enacted by the previous RPS law, SB 1078) refers to the cost cap contained in that provision, not to any limitation imposed on compliance with section 399.20 with respect to the RPS program. Moreover, SB 2 (1x) has substantially modified section 399.15, such that when SB 2 is implemented the RPS cost cap will be eliminated in its current form. Thus, under either the current or new section 399.15, there is no requirement or authorization in law that the utilities' suspend their SB 32 program when (if) the 33 percent mandate is met.

PG&E's proposed tariff

PG&E's proposed tariff also has a number of serious problems.

Sheet 1 states that any qualifying project:

> (3) Is strategically located and interconnected to the electric transmission or distribution system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

PG&E should add to this paragraph that entering into an interconnection study agreement under either state or federal-jurisdictional interconnection procedures, prior to the Commercial Online Deadline, will suffice for the purposes of this paragraph and that no other authority is conferred on PG&E by this language. Requiring a completed Phase 1 study or a completed interconnection agreement is not part of SB 32, as discussed above. The Clean Coalition recommends requiring that applicants submit an interconnection study application within 30 days of receiving an SB 32 queue position, or enter the next available cluster study window.

Rates are specified as follows on PG&E's tariff Sheet 1:

> PG&E shall purchase the output produced by an Eligible Renewable Energy Resource pursuant to the terms set forth in Section 2.4 of the Small Renewable Power Purchase Agreement Generator PPA at the applicable Market-Price-Referent (MPR) in the table in Section 612 of the Special Conditions in this Schedule from the date the Eligible Renewable Energy Resource begins actual commercial operation.

The Clean Coalition strongly recommends that the applicable rate be triggered instead by the SB 32 queue position date – not the online date. Many hurdles may delay project completion beyond the expected COD and it is not fair to developers to penalize them in terms of a lower rate (assuming rates are lower at a later date), or reduced certainty with respect to the rate they can expect, due to matters outside of their control.

We note also that PG&E's proposed tariff includes the old Time of Delivery table, which should be updated to reflect the 2011 table.

Special Condition 2 (Sheet 1) should include a clarification that the limitation on other program benefits is project-specific, not applicant-specific (as discussed above with respect to SCE).

PG&E also seeks to require that applicants use FERC-jurisdictional interconnection procedures only (Sheet 2):

> 4. Electrical interconnection to support this Schedule shall be accomplished using PG&E's Wholesale Distribution Tariff Attachment I for distribution voltage interconnection and CAISO's Tariff Appendix Y (effective December 19, 2010) for transmission voltage interconnection. As part of the electrical interconnection process, the customer, PG&E, and the CAISO (if transmission) will execute a FERC-approved Small Generator Interconnection Agreement ("SGIA"). Service under this Schedule is not available to customers interconnecting to PG&E's Secondary Network.

The Clean Coalition disagrees for the same reasons discussed above – namely, that the Commission should finish its Rule 21 revision process sometime in 2012 and at that time may require that some or all wholesale DG projects, including SB 32 projects, interconnect under Rule 21. The Clean Coalition has described its concerns with WDAT and CAISO procedures in other documents submitted to the Commission and we won't rehash our concerns here. We have, however, recommended – and will continue to do so – that all wholesale DG projects be considered under state jurisdiction as much as is allowed within the law.

PG&E should also explain why it seeks to prevent customers interconnecting to its Secondary Network (Sheet 2, Special Condition 4, last sentence) under this program. This may exclude a number of attractive rooftops and parking lots for solar projects because most of PG&E's Secondary Network is in urban portions of the Bay Area.

SDG&E's proposed tariff

SDG&E's tariff is the least problematic of the three IOUs. However, SDG&E's suggestion to keep the tariff at 1.5 MW and below should be rejected and the limit should be expanded to 3 MW.

SDG&E should also clarify how applicants must demonstrate that the proposed project is not "part of a multi-facility installation" (Definitions, Sheet 2, para. (3)). The Clean Coalition agrees that some kind of "anti-splitting" rules should be imposed to prevent applicants from splitting a larger project into 3 MW or smaller chunks in such a way that contravenes the intent of SB 32. However, such rules should be clear and vetted thoroughly by the Commission.

Conversely, we disagree that parties should not be allowed to aggregate smaller projects (Definitions, Sheet 2, para. (3)) under a single SB 32 contract as long as the projects don't exceed, jointly, the 3 MW limit. We see no harm in allowing such aggregation. We generally approve of PG&E's proposed PPA language on this issue (proposed PPA for 1-3 MW projects, section 3.1(g)(iii)(A)):

> (A) An Aggregated Project shall mean two or more facilities located on one or more contiguous or non-contiguous sites, each of which individual facilities is composed of units that are under common ownership of the Seller, employ the same technology and produce the same type of Product, and each of which has a nameplate capacity of no less than 500 kWs, provided that all the facilities comprising the Aggregated Project share a single resource ID (that is, are deemed to deliver to the same PNode).

We do not support SDG&E's proposed 500 kW aggregation limit, because it may preclude the use of many suitable rooftops or parking lots for solar, for example. The real limit on aggregation will be the cost of interconnection studies for each aggregated project vis-à-vis the SB 32 PPA price, so it is unlikely that parties will find it economically feasible to aggregate more than a few projects under a single SB 32 contract, or to try and aggregate projects much smaller than a few hundred kilowatts – obviating the need for an arbitrary limit on size.

III. Proposed PPAs

SCE

SCE's proposed PPA is highly problematic for a number of reasons, not least of which its attempted imposition of extremely burdensome paperwork on developers. Such a burden is inappropriate and probably a deal killer for many SB 32 developers who don't have the resources for such a burden. In keeping with the principles of transparency, longevity and certainty, the Commission should require that SCE substantially modify its PPA in order to reduce the burden on developers, and increase the transparency and certainty of the SB 32 program by reducing the complexity of the PPA.

Section 1.01(d) states: "Product: All electric energy produced by the Generating Facility throughout the Delivery Term, net of Station Use; all Green Attributes; all Capacity Attributes; and all Resource Adequacy Benefits; generated by, associated with or attributable to the Generating Facility throughout the Delivery Term." SCE should clarify in this provision that the SB 32 PPA does not include Resource Adequacy Benefits, by necessity, and it needn't mention them at all.

SB 32 does not require that projects achieve full deliverability (and thus qualify for Resource Adequacy payments). Moreover, payment for Resource Adequacy Benefits will, if it occurs in each instance, occur outside of the SB 32 contract, with compensation entirely separate from the SB 32 contract. SCE should, at the least, include a clarification like that which appears in its CREST PPA section 6.4: "SCE shall pay Producer for all Attributes and electrical energy."

Seeking full capacity deliverability should be a developer/Seller choice. This is the case because for smaller projects full deliverability costs may be a substantial share of the total project cost and may nudge a project from viable to unviable. Exacerbating this is the fact that CAISO[2] Phase 1 deliverability studies only yield +/- 50% accuracy and it is not until Phase 2 studies are completed – up to two years after a party submits an SB 32 application – that the applicant will have any certainty with respect to the costs of network upgrades required to ensure full capacity deliverability.

Even if full capacity deliverability costs are not found to be substantial in specific cases, when the studies and upgrades are completed, no developer will be able to commit to the $20/kW development security (section 3.06 and PG&E proposed PPA section 8.4) required by SCE prior to knowing its financial obligations for full deliverability. SCE seeks to require the development security within 30 days (5 days for PG&E) of the Effective Date of the SB 32 PPA and to require that applicants have a completed Phase 1study or completed Interconnection Agreement at the time of application. However, due to the fact that the Phase 1 study only provides +/- 50% accuracy of network upgrade costs, this requirement will be a nonstarter for applicants who don't already have a Phase 2 study completed. These requirements are, combined, far too onerous for an effective SB 32 program.

There are also a number of blanks in SCE's proposed PPA that make it impossible to weigh definitively. SCE should fill in the blanks and re-submit.

Section 1.04(b) should be modified to include the phrase, after "regulatory delays," "including any delays in interconnection resulting from utility or CAISO delays."

[2] CAISO performs all deliverability studies.

Section 1.05 should be modified to include "subject to the 50 hours per year curtailment limitation in section 1.09."

Section 1.06 discusses pricing, with special formulas for wind and solar. The Clean Coalition strongly objects to the additional complexity and uncertainty that SCE seeks to impose on wind and solar SB 32 projects. In keeping with the guiding principles of transparency, longevity and certainty, we recommend that all pricing be based on a single base value applicable to each tranche, which forms the base for the volumetric and locational benefits adder pricing formula, as described further below. Our approach is far simpler than SCE's suggested approach and provides far more certainty to developers and policymakers as to the actual price to be paid for power from SB 32 projects. Moreover, key values are left out of SCE's proposed formulas, making any judgment on their merits impossible.

Section 1.07 should be stricken because Seller is already heavily incentivized to produce as much power as possible due to the fact that Seller is not compensated for non-production under a FIT.

Section 1.10 seeks information that is of no concern to SCE and should be struck. Whether an applicant obtains an ITC, PTC or cash grant has zero impact on SCE's responsibility to pay for power from an SB 32 project.

Section 1.11 has a reference to projects smaller than 5 MW and projects greater than 5 MW, which is an error and a holdover from the RAM contract. The same section refers to the costs of compliance with procuring "capacity attributes" and "resource adequacy," which have no place in this PPA. SB 32 does not require resource adequacy to be provided by SB 32 projects. Rather, it requires only that if a project qualifies for resource adequacy it must provide such to the purchasing utility. However, this benefit is not part of the SB 32 contract price. Rather, it is a separate contract price to be achieved through a separate application for resource adequacy payments. As such, (c) and (d) should be stricken and the PPA revised accordingly.

Similarly, section 2.02(b) has no place in this PPA because it concerns interconnection. The PPA should cover only those issues necessary for sale of power to SCE. Section 2.02(b) should be stricken. The same section states: “Seller’s interconnection agreement shall reflect that the Generating Facility has Full Capacity Deliverability Status.” As we have explained above and in previous comments, SCE cannot require full capacity deliverability for SB 32 facilities. This is yet another reason to strike this section in its entirety.

Similarly, section 2.03(b)(ii)(3) must be stricken because it yet again seeks to require full capacity deliverability before commencement of operations. Section 2.03(b)(ii)(7) should also be stricken because it refers to the section 1.07 Performance Assurance that Clean Coalition believes should be stricken.

Section 2.04(a)(i)(3) should be modified to 18 months (rather than 12) because some jurisdictions, such as Kern County, require a full EIR for all projects, which will take at least a year by itself.

Section 2.04(a)(ii) should be stricken because it is not relevant to SCE’s purchase.

Section 2.04(a)(iii) should be stricken as unnecessary, overly complex and uncertain.

Section 2.04(b) should include a cure period for an Event of Default.

Section 2.05(a)(ii, iii, x, and xi) should be stricken.

Section 2.05(b) must be stricken as it seeks to impose an entirely unjustified two year “restriction period” on the Seller’s ability to sell power from the erstwhile SB 32 facility in the event of lawful termination of the contract. There is no basis in law or policy for such a limitation.

Section 3.01(a) should clarify that "Metered Amounts" does <u>not</u> include power consumed on-site, per the excess sales option.

Section 3.01(d) should be stricken because there is no basis in law or policy for Capacity Attributes or Resource Adequacy to be required for SB 32 projects (as discussed above). As we have explained, if a facility chooses to obtain Resource Adequacy benefits it must under SB 32 provide such benefits to SCE. But it has a choice as to whether or not to pursue such benefits. This is a key distinction. Thus, section 3.01(c) has a basis in law, but section 3.01(d) does not.

Similarly, section 3.02 should be stricken.

Section 3.05 should be modified to clarify that "if Seller chooses to obtain Resource Adequacy Benefits" it must also comply with the provisions in this section. As is, this section is not in compliance with SB 32 for all the reasons stated above with respect to Resource Adequacy requirements and full capacity deliverability.

Section 3.06(b)(i) should be modified to require posting of the Development Security 30 days after Seller receives its Phase 1 study results or SIS or Fast Track Initial Review. This is the case because, as discussed above, the Clean Coalition finds it too onerous to require that applicants have a Phase 1 study in hand (an interconnection study should be applied for within 30 days of the SB 32 application being deemed complete), requiring also that the Development Security posting be adjusted accordingly.

Section 3.06(f) refers to projects up to 5 MW and over 5 MW, another holdover from the RAM contract that needs to be modified for SB 32.

Section 3.06(h) should be stricken as there is no basis in law or policy for such a draconian restriction on Seller's rights.

Section 3.07 should be stricken as it is not clear why SCE would incur compensable damages in the event of the non-performance by Seller described in this section.

SCE should clarify whether section 3.08 applies if full capacity deliverability is not sought by Seller. If it does not, this section should be modified to impose requirements on Seller only when appropriate. More generally, the Clean Coalition requests that the IOUs explain to parties why any additional telemetry equipment should be required when advanced meters and trips (DTTs) are already required for all projects?

Section 3.08(f) should be stricken. This section only applies if Seller chooses full capacity deliverability and even then this section has no place in this contract. Rather, if Seller chooses full capacity deliverability it will enter into a separate contract where these kind of requirements may be appropriate. As is, this section is inappropriate and unnecessary.

Section 3.09(a) should remove "in SCE's sole discretion" and insert "must be reasonably granted by SCE."

Sections 3.11(c)(viii)-(xxiv) should be stricken. SCE has no real need for this information and it seems to be seeking additional onerous requirements on Seller.

Section 3.12(c)(vi) should be clarified to explain whether it applies only to Sellers seeking full capacity deliverability or to all Sellers.

Section 3.12(c)(xii) is inapplicable and should be stricken (another holdover from the RAM contract).

Section 3.12(d), (e) and (g) should be stricken as overly onerous and confidential to Seller.

Section 3.12(f) should include a clarification that it is "subject to the curtailment cap in section 1.09."

Section 3.12(i) represents a more reasonable requirement, but we don't believe an independent electrician is necessary. Self-certification should be sufficient.

Section 3.16 seeks to require monthly reporting on Seller's progress in meeting milestones. This is too onerous and should instead be required every 6 months, as recently required by the Commission with respect to the RAM.

Section 3.17(a)-(h) should be stricken as too onerous. SCE seeks to act as a regulator for SB 32 generators – this is not SCE's role. Rather, SCE should be allowed to require only that information from Seller that is <u>absolutely required</u> to ensure safe interconnection and operation of the SB 32 facility. The items in Section 3.17(a)-(h) do not fall into this category and nor do many other items mentioned above. Interconnection information is handled entirely through established interconnection procedures (WDAT, CAISO or Rule 21 currently) and has no place in the SB 32 PPA.

Section 3.18 seeks to impose an Availability Guarantee Lost Production Payment, under the following formula from Exhibit R:

AVAILABILITY GUARANTEE LOST PRODUCTION PAYMENT = [(A – B) x (C x (D - E))]

D – E cannot exceed 2 c/kWh, so Seller may face up to 2 c/kWh as a penalty under this provision. SCE should explain the rationale for this proposed penalty. The Clean Coalition's feeling is that such penalties are unnecessary because Sellers are already highly incentivized to produce as much power as possible from their facilities, obviating the need for penalties for non-production.

Section 3.23 seeks to require monthly Lost Output calculations and reports to SCE. We recommend that this be required every six months as there is no material harm from a twice yearly approach and this will substantially reduce the workload for both Seller and SCE.

Similarly, section 3.23 should be amended to require Actual Availability reports on a twice yearly basis, not monthly. The requirements SCE seeks to impose on SB 32 projects, some of which may be less than 1 MW, are extremely onerous. A concerted effort needs to be made by the Commission and SCE to reduce these requirements if the Commission wishes to create a functional program under SB 32.

Section 3.24 should be modified to require reporting only once every six months, not monthly.

Sections 3.25 and 3.26 should be stricken. Site-specific wind and insolation data are highly proprietary and SCE does not need historical wind or insolation data to safely purchase power from SB 32 projects. Moreover, we have recommended earlier in these comments that SCE's suggested capacity factor-adjusted FIT price be eliminated in favor of a single FIT price adjusted by TOD and locational benefits. Developers seeking to develop SB 32 projects are responsible for determining whether the SB 32 price offered will result in a viable project – this is not SCE's role. This suggestion by SCE in their PPA raises troubling concerns about the use of such data by SCE. The Commission should, if it doesn't already, ensure that such data is not passed to SCE's UOG arm or affiliates for scoping of their own projects.

Section 4.02(a)(ii) should also clarify that any curtailment is subject to the 50 hour total annual limit in section 1.09.

Section 6.01(b)(xix) includes "Seller transfers or assigns the Interconnection Queue Position" as an Event of Default. This is an overly broad limitation and should be modified to allow transfer or assignment of an interconnection queue position in the event that Seller's company is sold or changes names.

Section 8.02(a) should be stricken because it relates to the section 1.07 Performance Assurance that the Clean Coalition believes should not be required.

Section 8.03 should be stricken.

Section 10.06 (abandonment) should be modified to increase the 30 day limit to 180 days. Equipment procurement issues or permitting issues can often lead to delays of much longer than 30 days.

Exhibit F should be removed because there should be no Product Replacement Damage provision, as mentioned above.

PG&E's proposed 1-3 MW PPA

The Clean Coalition recommends that PG&E issue just one SB 32 PPA. We understand that the 1 MW and smaller PPA is simpler but we'd prefer to have just one contract for all SB 32 projects – as would developers seeking to understand their obligations under the proposed PPA. <u>We provide comments herein on PG&E's 1-3 MW proposed PPA only.</u>

Section 1.62 Delivered Energy limits projects to a maximum of 3 MWh/hour. The Clean Coalition recommends, however, allowing up to a 20% overproduction of nameplate capacity. This is the case, as we argued in the RAM proceeding, because renewable energy facilities may often over-produce in optimal conditions and it makes no sense to penalize SB 32 project owners for such over-production. Concerns about grid reliability are mitigated when we consider that the vast majority of SB 32 projects will never send power into the transmission system because it will be consumed on the distribution grid near where it is produced. The Commission agreed with our recommendation in its draft RAM resolution E-4414, stating:

> The Clean Coalition, Solar Alliance, SunEdison, and Foristar Methane protested PG&E's proposed Guaranteed Energy Product Section 3.1(e)(II)(E), which states that energy delivered in excess of 20 MW/hour will not be credited toward or added to Seller's Guaranteed Energy Production Requirement. SunEdison states that limitations on annual production are unnecessary, but could be capped at 120% of forecast annual production, as

> PG&E has done in previous contracts. Staff agrees with SunEdison and rejects PG&E's proposed language. Staff directs PG&E to modify this term to cap excess generation that can be credited toward the seller's guaranteed energy production requirement at 120%. Staff recommends the Commission adopt the following language:
>
> <u>PG&E shall change Section 3.1(e) (II)(E) to allow for annual production up to 120% of forecast annual production to be credited toward or added to Seller's Guaranteed Energy Production Requirements.</u>

Similarly, section 3.1(f) seeks to relinquish PG&E of any obligation to purchase power in excess of 110% of nameplate capacity. Under the same rationale just presented, the Clean Coalition recommends that up to 120% of nameplate capacity should be compensated at normal rates.

Section 3.1(g)(ii) imposes unwarranted restrictions on assignment. The Clean Coalition recommends that this section be eliminated or amended such that it imposes no restrictions on assignment other than that the new owner of the contract must meet and maintain all SB 32 project requirements.

Section 3.1(h)(i) contains a mistaken reference to SGIP interconnection procedures, which have been eliminated in favor of the GIP for utilities and CAISO. This section should be amended to refer only generically to interconnection procedures because it is likely that the Commission will require Rule 21 for some SB 32 projects.

Similarly, section 3.1(h)(ii) refers to SGIA – the Small Generator Interconnection Agreement. Section (h) could be eliminated in its entirety and the contract would be improved. As discussed above with respect to the proposed tariffs, interconnection issues are out of place in the proposed PPAs because interconnection issues are resolved entirely through an independent interconnection procedure (Fast Track, ISP, cluster, for either the utility or CAISO) managed by a different branch of PG&E or by CAISO.

Section 3.3 concerns deliverability and is problematic insofar as PG&E seeks to require in this section at least preparation for full capacity deliverability for all SB 32 projects. Section

3.3(a) states (emphasis added): “During the Delivery Term, Seller grants, pledges, assigns and otherwise commits to Buyer all of the Project’s Contract Capacity, including Capacity Attributes, from the Project to enable Buyer to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO or other regional entity may prescribe.” As this section notes, the Commission is developing RA rules, but the Commission has also recently disallowed mandatory deliverability requirements, where there are network upgrade costs, in the RAM program (Res. E-4414).[3]

The Clean Coalition reiterates its objection to mandatory deliverability as an unwarranted requirement. Rather, deliverability should be a developer/Seller choice in every instance. As discussed above, SB 32 does not require that projects achieve full capacity deliverability. Rather, it requires only that if a project achieves full deliverability that it must provide such value to the host utility. At most, the Commission should require, as it did in RAM, that Sellers apply for deliverability and sell RA benefits to utilities’ only where there are found to be no network upgrade costs.

With respect to section 3.6, we request that PG&E clarify why a CAISO meter should be required for all SB 32 projects, including distribution-interconnected energy-only projects, which will likely be the lion’s share of SB 32 projects.

Section 3.9(vi) seeks to impose monthly reporting requirements on Seller with respect to construction. This is more frequent than required and we recommend, as with SCE, that reporting requirements be limited to once every six months (as is required in the recent RAM resolution[4]).

[3] P. 17, emphasis in original: “The IOUs proposal to require a seller to achieve full deliverability status is rejected. The IOUs shall remove the requirement that the seller must achieve full deliverability status from the bidding protocols and the standard RAM contracts.”

[4] Appendix A, 6. Market Elements. a. “Project Milestones”: “Sellers shall submit a project development milestone timeline to the IOU upon RAM contract signing, and quarterly progress reports every six months.”

IV. Responses to other parties

SCE

SCE states (Opening comments, p. 2):

> [A] Commission-established requirement that utilities pay Section 399.20 generators the MPR is unlawful under the Federal Power Act. It would also require utility customers to pay such generators an administratively-determined price that is not consistent with actual market conditions. This is likely to lead to higher prices for customers and is contrary to Section 399.20's ratepayer indifference mandate.

The Clean Coalition disagrees with this statement, as we have discussed in opening and reply briefs submitted in R.08-08-009 (Clean Coalition Opening Brief, March 7, 2011, p. 22, citations omitted):

> FERC has made clear in recent decisions that states have authority to set "multi-tiered" FIT rates under PURPA's avoided cost methodology, if state law requires that utilities procure renewables under, for example, a Renewable Portfolio Standard, and if projects are registered as Qualifying Facilities (which is not a particularly onerous requirement). The methodology prescribed in SB 32, which we have commented on in this section, will not, however, result in a multi-tiered FIT. Rather, it will create a single-tiered FIT – a single base price applicable to all renewable energy technologies. As such, there is even less room for disagreement over federal precedent in this area because the Commission will be setting just one base rate for all SB 32 technologies, with Time of Delivery pricing varying by technology and location of projects.

Accordingly, if projects certify as QFs, there is no preemption issue. The Commission agreed with this interpretation in at least two recent decisions, including D.11-06-016 (p. 10, we discuss this decision in more detail in our reply below to DRA's opening comments):

> A recent FERC order reiterates the Commission has a wide degree of latitude in establishing avoided cost rates under PURPA and clarifies that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided costs requirements of PURPA. (*California Public Utilities Commission,* 133 FERC ¶ 61,059 (October 21, 2010) at 20 and 24.) As this FERC order explains, avoided cost rates under PURPA may "differentiate among [QFs] using various technologies on the basis of the supply characteristics of the different technologies." (Id. at 23.) The order further states that avoided cost rates for purchases from QFs must be, among other things, at rates that

> are not in excess of the "the incremental cost to the electric utility of alternative electric energy" which is further defined as "the cost to the electric utility of the electric energy which, but for the purchase from [the QF], such utility would generate or purchase from another source." (*Id*. at P 22.)

SCE also objects to the Commission's proposed division of 2011 and 2012 issues to be addressed (p. 3):

> [T]he Commission cannot defer consideration of statutory requirements like denial of tariff requests and contract termination provisions. These legal requirements of Section 399.20 are interrelated to other aspects of the program, and the Commission cannot direct the utilities to offer tariffs and contracts without procedures for denial of tariff requests and termination of such contracts. SCE believes that expedited interconnection procedures may be deferred; however, all of the other issues identified in the Section 399.20 Ruling should be considered and addressed by the Commission before it issues a decision adopting revised tariffs and contracts.

SCE believes that an auction approach to setting pricing for SB 32 will include environmental costs (p. 4): "Moreover, a market-based process will allow the 'current and anticipated environmental compliance costs' discussed in Section 399.20(d)(1) to be included." This is not necessarily the case because SCE has suggested that its MP FiT start at the day ahead price, which does not include all environmental compliance costs because this price includes dirty power as well as clean power – and for this reason and others this price will be wholly insufficient to support SB 32 projects. SCE's price increase formula may allow the price to reach a level, through monthly price increases under the formula they suggest, that could include environmental compliance costs, but it will probably be some time before that happens under SCE's proposed formula. The state can't afford to wait for this to happen.

SCE makes a number of contradictory and unsupported statements with respect to pricing (p. 4):

> SCE's proposed market-based methodology avoids the legal and practical pitfalls of establishing an administratively-determined price with static inputs and assumptions that cannot respond to market conditions. For

> example, the MPR benchmark established by the Commission and advocated by certain parties as the price for Section 399.20 contracts does not reflect market conditions. Indeed, prices for SCE contracts obtained through RPS solicitations and other renewable procurement mechanisms have been both higher and lower than the MPR. Using a stagnant administratively-determined price with no connection to market conditions is unlikely to reflect the costs to the seller, or benefits to the buyer, or the lowest cost to which the buyer and seller would agree. Requiring customers to pay more for power than they otherwise would pay would violate the ratepayer indifference standard in Section 399.20, and could result in protracted litigation.

First, the MPR is indeed a type of market price – as its name suggests. SB 32 does not specify what exactly "market price" should be, which is why the Commission has asked for party comments on this issue. We agree with SCE that the MPR is not meant to be an actual market price for renewables, as in the actual cost for renewables today. Rather, it is the calculated cost of power from a new 500 MW natural gas facility, which was chosen by the Commission as the best proxy for determining cost reasonableness for renewables. We have suggested in our opening comments that the 2009 MPR should be used as the starting point for SB 32 pricing because of this history with respect to the MPR and cost reasonableness. Our proposed mechanism then allows the actual market response under SB 32 to determine how pricing changes over time.

PG&E

The Clean Coalition is pleased to see that PG&E has maintained its position that MPR plus TOD pricing is appropriate for SB 32. PG&E's previous position on this issue, in its Opening Brief (March 7, 2011), was one reason we chose MPR plus TOD pricing as our suggested pricing mechanism for early implementation of SB 32.

We disagree, however, with PG&E with respect to using the 2011 MPR instead of the 2009 MPR, and with linking SB 32 pricing to the MPR in future years. As the Commission has suggested, there is no requirement, with SB 2's changes to section 399.20, that the Commission use the MPR at all for SB 32 pricing. We have, however, suggested that the

2009 MPR is the best starting point for pricing under SB 32 (what we have labeled the Volumetric Market Price or VMP) because of its history and rationale – but also because we believe that the market response to 2009 MPR plus TOD pricing will be good under SB 32. We do not have similar confidence that the 2011 MPR plus TOD will produce a good market response because it is likely, given reduced natural gas prices today, that the 2011 MPR will drop by about 10 percent from its 2009 value. A 10 percent reduction in PPA price is very substantial for the economic viability of projects.

We note also that PG&E's proposed tariff includes the old Time of Delivery table, which should be updated.

DRA

The Clean Coalition appreciates DRA's statement of support for distributed generation as a cost-effective means for reaching the state's RPS mandate (p. 2):

> DRA continues to support the Commission's advancement of distributed generation renewable energy programs as a cost effective means of meeting California's renewable energy mandates and providing opportunities for small-scale renewable developers to participate in the State's renewable energy market. An effective Feed-in Tariff (FiT) program**2** under §399.20 is a critical component of the 33% RPS goal due to the program's potential to provide cost-effective near-term renewable energy

While we appreciate DRA's support in theory, we do not agree with DRA's suggested pricing methodology. DRA suggests that the net metering surplus pricing in D.11-06-016 is an appropriate pricing approach for SB 32. The Clean Coalitions believes that this is an inappropriate avoided cost approach for SB 32 and would lead to an inadequate price level to bring any SB 32 projects to fruition. As the Commission has described in D.11-06-016, FERC has made it clear that states may craft avoided costs based on the specific energy resource required by state law. In the case of SB 32, <u>the appropriate avoided cost is the cost of power from long-term contracts from renewable energy projects 3 MW and below</u> – not the DLAP (Default Load Aggregation Point) avoided cost that the Commission relies on in

D.11-06-016. There is no relation between the DLAP and the appropriate SB 32 avoided cost because DLAP is based the day ahead market price for all electricity.[5]

The Commission clearly distinguishes in D.11-06-016 long-term contracted power under programs like SB 32 (and AB 1969) and net surplus power under AB 920, in a passage worth quoting at length (pp. 32-33, emphasis added):

> We reject the Joint Solar Parties' suggestion to base the NSC [net surplus compensation] rate on the Commission-adopted MPR, plus additional adjustments, for several reasons. First, we reject the proposal to rely on an MPR-based NSC rate because the MPR represents the cost to construct, operate and maintain a 500 MW combined cycle gas turbine, and we do not believe that surplus generation from NEM customers will result in avoided procurement from such a facility. Rather, we find that surplus generation from NEM customers is more likely to avoid short term wholesale purchases by the utilities. Thus, an MPR-based NSC rate would be inappropriate. As SCE and TURN both note, the MPR is a legislatively mandated metric intended as a cost benchmark for RPS projects with a known energy output, while NSC involves payment to NEM customers for an inherently unknown amount of net surplus generation. We agree with TURN that net surplus generation bears greater similarity to short term energy purchases by the utilities than the output of a long-term renewable generator under a power purchase agreement. As TURN notes, surplus generation cannot be forecast and only reduces real time market purchases. It does not serve as a hedge against gas price volatility so it should not be compensated as such. Since an individual NEM customer has no obligation to provide any energy to the utility, the only generation cost that the utility avoids when an NEM customer provides surplus is the reduced procurement of electricity from the CAISO wholesale market. While Joint Solar Parties contend the MPR should determine the NSC rate because it is used to pay generators under AB 1969 tariffs, <u>we find the AB 1969 program is distinguishable from NSC because AB 1969 involves contracted power, while NSC involves payment for incidental, non-contracted power production</u>.
>
> Second, we reject the proposal to use the MPR to set the NSC rate because <u>we agree with the utilities and TURN that it is not appropriate to pay</u>

[5] DRA also states that (p. 6): "some participants have found that relying on the MPR metric as a price point is an unrealistically low/unachievable price point for certain technologies and, accordingly, use of the MPR may have a negative impact on the overall success of the program." It is puzzling to the Clean Coalition how, given this concern by DRA for appropriate pricing support, they would now shift from previously supporting MPR pricing for SB 32 to DLAP pricing plus RECs because DLAP plus RECs pricing will be approximately half the price support as MPR plus TOD. D.11-06-016 shows that probably DLAP plus REC pricing will be approximately 6 c/kWh for PG&E – a price level that will not be viable for any SB 32 projects, as we know from experience with AB 1969.

> net exports which can be occasional, intermittent, and unpredictable, using a cost methodology that assumes a long-term projection of costs and includes a value for capacity. As SDG&E notes, NEM customers are not under a long-term contract to provide surplus generation.

We have suggested in our opening comments that the avoided cost for 3 MW and smaller renewable energy projects is best determined by the market response to an initial set price (we recommend the 2009 MPR plus TOD). Due to our recommended degression or price increases, the actual avoided cost for the SB 32 market segment will quickly be discovered.

DRA conditionally supports using MPR plus TOD pricing for SB 32 in 2011 (p. 8): "An MPR based price would be acceptable for the 2011 timeframe until the California Energy Commission (CEC) has calculated the price of the renewable energy credit (REC) green attribute component." The Clean Coalition has advocated a similar approach for early implementation of SB 32 in 2011, which will allow the Commission to gauge market response and degress or increase the SB 32 price accordingly.

IREC

The Clean Coalition supports IREC's suggestion that distribution grid upgrade costs be waived (and thus rate-based) for SB 32 projects when such projects comprise less than 100% of minimum load on the "distribution feeder." IREC states (p. 11):

> To encourage the siting of distributed generation on distribution circuits where generation can serve nearby load, IREC recommends that the Commission extend the cost waiver for distribution system upgrades that is currently in place for net-metered systems to cover additional types of generators that meet certain requirements. Presently, net-metered customers do not pay the cost of distribution system modifications that may be required to accommodate the interconnection of a net-metered system. Such costs are instead incorporated into utility distribution system costs that are paid by all ratepayers.

We recommend, however, that the Commission, if it adopts this recommendation, require the utilities to expeditiously add line section data to their interconnection maps. Minimum circuit load data could readily be added to the maps, whereas the utilities have pushed back on providing line section data at this time. We have urged the Commission to require that the utilities provide line section data, in addition to circuit data, in order to allow developers access to the relevant data for Fast Track (which is based on line section data), but the Commission has yet to accept this recommendation. Accordingly, tying the waiver of distribution grid upgrade costs to line section data would be improved by requiring also that the maps be improved.

IREC states (p. 12): "IREC recognizes that a small number of distribution feeders may be costly to upgrade and should be excluded from an expanded cost waiver." The Clean Coalition suggests that the cutoff for what "should be excluded from an expanded cost waiver" are those areas of the distribution grid that would require upgrade costs greater than 10% of the likely cost of a proxy SB 32 project. Since the large majority of SB 32 projects are likely to be solar PV, <u>we recommend that the Commission require (if it adopts IREC's recommendation) the utilities' to determine, as a general matter, what areas are to be excluded from the distribution cost waiver, based on the average cost of ground-mounted solar PV systems smaller than 10 MW that have bid into the utility PV programs in 2011</u>. (We generally oppose using auction pricing for SB 32, because of our concerns about the "race to the bottom" prompted by auctions as a general matter, but in this case we see it as the best proxy cost for determining waiver eligibility). The Commission should also ensure that implementation of this process for determining waiver eligibility is fully subjected to stakeholder scrutiny in this proceeding or its successor.

If the Commission adopts IREC's suggested distribution grid upgrade cost waiver, the Clean Coalition retracts its suggested TAC proxy for locational benefits. This is the case because waiver of upgrade costs would be an equivalent means for calculating locational benefits.

Respectfully submitted,

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Dated: August 26, 2011

VERIFICATION

I am an attorney for the Clean Coalition and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 26th day of August, 2011, at Santa Barbara, California.

Tam Hunt

Clean Coalition