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

AMENDED CLEAN COALITION COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON THE RENEWABLE AUCTION MECHANISM

Rulemaking 11-05-005
Decision 10-12-048

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I. Introduction

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to local energy systems through innovative policies and programs that deliver cost-effective renewable energy, strengthen local economies, foster environmental sustainability, and provide energy resilience. To achieve this mission, the Clean Coalition promotes proven best practices, including the expansion of Wholesale Distributed Generation (WDG) connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove barriers to the procurement and interconnection of WDG projects, integrated with Intelligent Grid (IG) solutions such as demand response, energy storage, and advanced inverters. The Clean Coalition is active in numerous proceedings before the California Public Utilities Commission, the California Energy Commission, and other state and federal agencies throughout the United States. The Clean Coalition also designs and implements WDG and IG programs for utilities and state and local governments.

The Clean Coalition supports the reauthorization of the Renewable Auction Mechanism (RAM) with additional bid equalization factors. We propose streamlined methodologies for quantifying the following locational value for ratepayers: avoided Transmission Access Charges, avoided future Transmission Access Charges, avoided line losses, and local capacity value.

The Clean Coalition supports reauthorization of minimum procurement levels to maintain the market, while also using RAM as a mechanism to procure energy to meet operational needs and policy goals. We propose that RAM projects be included in competition with bids in RPS and other RFOs where RAM projects meet the eligibility criteria.

The Clean Coalition also opposes transfer of utility solar program allocations for 1-3 MW projects to the RAM. We recommend that the Commission protect allocations for smaller projects, recognizing that developers have reasonably relied upon such allocations.

The Clean Coalition also recommends that the Commission both define the criteria for establishing site control and approve standard forms for proof of site control. The Clean Coalition recommends the form used by the Los Angeles Department of Water and Power for its solar feed-in tariff program, attached to these comments as Exhibit A.

II. Comments on Renewable Auction Mechanism

Energy Division Staff drafted a series of questions incorporated into the December 31st, 2013 Ruling to help inform the Commission's review of the Renewable Auction Mechanism (RAM) program. The questions were separated into four sections: (1) Reauthorization (2) Program Elements (3) Eligibility and Viability (4) Contract Terms and Conditions. We address these questions in the following comments.

1) Reauthorization of RAM:

The Commission created the RAM program to meet a specific RPS program need not fulfilled through the annual RPS solicitation.

a) Does the initial RPS program need that the RAM program sought to fulfill still exist?

Yes. RAM was designed to provide a procurement mechanism for the 3-20 MW RPS-eligible market segment, and the need for that market segment will continue.

Recognizing inherent barriers in the RPS solicitation process, RAM was created to provide a viable market and cost effective procurement for 3-20 MW RPS-eligible projects. The value of a streamlined procurement process still exists in order to access the values offered by this market sector at competitive pricing. This targeted procurement mechanism should be retained and improved at least until replaced by an effective alternative.

D.10-12-048 states:

> "This decision authorizes a new procurement process called the Renewable Auction Mechanism, or RAM, for the procurement of smaller renewable energy projects that are eligible for the California Renewables Portfolio Standard (RPS) Program… The Commission adopts RAM as a primary contracting tool for this market segment because doing so will promote competition and elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term. We expect RAM to complement the RPS Program by reducing transaction costs and providing a procurement opportunity for smaller RPS-eligible projects, which have not been able to effectively participate in the annual RPS solicitations to date." (p. 2)
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> "The rules adopted for RAM in this decision are intended to reduce transaction costs, promote regulatory certainty, and provide value to the market, utility, regulator, and ratepayer. For this initial implementation of the program, we direct [the IOUs] to use RAM to procure at least 1,000 MW, …over two years." (p. 2)
>
> "Our intent in establishing RAM is to create a standardized procurement process for projects up to 20 MW in size in order to promote robust competition and reduce the administrative burden associated with these projects. Going forward, RAM should be the primary procurement vehicle for projects in this size range, though projects may still participate in other Commission-authorized programs such as the annual RPS solicitations and Commission-approved utility solar photovoltaic programs." (p. 3)

The quantity of procurement needed from this market segment in any given year is a separate question from the need for a mechanism through which any such procurement is fulfilled. Concerns regarding procurement shortfalls in meeting the 2020 RPS were only one foundation cited by the RAM decision D.10-12-048. The decision states, "The Commission adopts RAM as a primary contracting tool for this market segment because doing so will promote competition and elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term… The rules adopted for RAM in this decision are intended to reduce transaction costs, promote regulatory certainty, and provide value to the market, utility, regulator, and ratepayer."[1]

The 2020 RPS target establishes minimum procurement of renewables, not a limit, and additional procurement will be necessary both to meet longer range state goals, including greenhouse gas emissions goals, and to replace expiring contracts. Ongoing procurement from the RAM market segment is essential for maintaining a competitive supplier market in this sector for California. As noted prominently in NREL's review of research and best practices led by E3 Analytics[2], one of the most important elements of renewable energy procurement policy success is the long-term stability of the policy. Therefore procurement should be continued under this or a successor mechanism in order to maintain a viable market in this important and cost effective sector.

While we support ongoing evolution and improvement in procurement practices, the following reasons for establishing RAM have not changed and RAM has successfully met those expectations of the Commission. As the Energy Division Summary attached to the Ruling requesting comments concluded:

> "The RAM program created a robust market for renewable energy projects sized 3 - 20 MW. The competition in this market has resulted in cost-effective procurement of viable projects, while minimizing transaction costs for the developer, the utilities, and the regulator relative to the annual RPS solicitations. In addition, there has been a robust response from the solar PV market segment, with lower response from the still-evolving non-peaking and baseload market segments."[3]

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[1] D.10-12-048 at p.2, emphasis added.

[2] A Policymaker's Guide to Feed-in Tariff Policy Design, NREL/TP-6A2-44849, July 2010. (citing Klein et al. 2008, Dinica 2006, Diekmann 2008, Fouquet and Johansson 2008, Ragwitz et al. 2007, COM 2008, Deutsche Bank 2009).

[3] Attachment A to the ruling requesting comments at 13.

b) Is there currently a different specific RPS program or system need (as may be identified from the long-term procurement planning process, i.e., need for renewable resources to meet local capacity requirements) that would be effectively and efficiently fulfilled through a RAM procurement mechanism rather than through the annual RPS solicitation or other procurement mechanism?

RAM represents a market sector that is critical for implementing "least regrets" procurement planning. RAM projects take advantage of economies of scale and can also be quickly sited and deployed to address evolving local capacity requirements. For example, maintaining the availability of RAM projects will allow policymakers to make fewer commitments to large-scale generation and transmission projects to meet future load growth in transmission-constrained areas like Southern California, displacing costly investments that may result in stranded assets if such large advance commitments are not actually required when eventually available, and higher emissions if procured fossil fueled capacity is utilized.

RAM projects may also be less likely to face delays or cancellation due to opposition to siting projects or transmission extensions on sensitive lands. We support the recommendations by the Natural Resource Defense Council, the Sierra Club, The Nature Conservancy and Defenders of Wildlife relating to environmental criteria for RAM projects.

RAM auctions can also enable California ratepayers to tap the locational benefits of distributed generation. If the locational values that the Clean Coalition recommends below are incorporated into the bid equalization process, ratepayers can access significant savings.

<u>RAM effectively establishes both an active pool of ready projects and a mechanism for efficiently selecting the least cost and best fit from that pool under existing criteria or additional criteria as appropriate.</u> While the Clean Coalition sees clear rationale for maintaining a minimum ongoing level of procurement to maintain a viable market in this sector, we see no reason to limit authorization of RAM from fulfilling any general procurement need where it is competitive. The RAM process is more efficient in both application and evaluation than an RFP. With the enhancements noted above, the RAM

process can also encourage participation of projects with higher locational value and lower environmental impact. Therefore, as discussed further below in response to question 2e, RAM bids should be automatically included in competition with in all RPS solicitations where the RAM projects meet qualifying criteria in order. By including and comparing existing RAM bids to RFP respondents, a larger and potentially more competitive pool of bids will be available, resulting in a more effective and efficient outcome for ratepayers.

> *c) If yes to either question (1.a.i) or (1.a.ii), what type of renewable resource would be procured to fulfill the identified need? Why isn't this resource being effectively or efficiently procured through the annual RPS solicitation, or why would a RAM auction better fill the need? Please provide a justification for the identified need, utilizing quantitative justification to the extent possible.*

This question is addressed in the responses to (1.a.i) and (1.a.ii), which identify the opportunities for projects that (a) can be deployed with fewer delays than larger projects, (b) have higher locational value, and (c) have lower environmental impact to utilize the relatively streamlined RAM process to more efficiently and effectively meet procurement needs in a Least Regrets planning approach.

> *d) Based on the response to question (a) above, what criteria should the Commission use for reauthorization of the RAM mechanism? If the Commission decides to reauthorize RAM, explain how reauthorization should or should not align with resource planning and the annual RPS Procurement Plan process?*

As RAM is the only mechanism providing streamlined bidding, procurement selection, standard contracts and approval for RPS-eligible projects greater than 3 MW, the Commission should retain the RAM mechanism unless and until a preferable alternative is available.

> *e) If the Commission decides to reauthorize RAM, explain how reauthorization should or should not align with resource planning and the annual RPS Procurement Plan process?*

Under AB 327, enacted in 2013, the RPS mandate does not limit the Commission's authority to require procurement of RPS-qualifying generation. While general resource planning and RPS mandates may appropriately look to RAM and other procurement mechanisms to meet projected minimum requirements, the Commission should also anticipate both 1) additional future renewable requirements in line with established long-term state emissions and sustainability goals, and 2) opportunities to both maintain a competitive market and obtain energy at the lowest delivered cost to customers, in order to establish the maximum authorized procurement.

> *f) If the Commission determined that a future authorization of the RAM mechanism was needed to serve a specific goal of the RPS program, what criteria should be used to determine the frequency of auctions and overall duration of the reauthorized program?*

The Clean Coalition supports continuation of semi-annual auctions. The Commission previously determined that semi-annual auctions were an appropriate frequency for this mechanism and market segment. Although the Commission has not always approved contracts selected prior to subsequent additional procurement, six months has proven to be more than adequate time for bid selection and consideration for contract approval. This interval allows either proposed or approved pricing results to be published and for new competitive bids to be entered to the advantage of ratepayers, while also providing timely information to the market to assist in determining which project proposals are worth developing and which may be withdrawn from the interconnection queue, thereby redirecting investment and resources more efficiently.

As noted above, the duration of the RAM procurement mechanism should extend until replaced.

A number of potential scenarios for reauthorization are provided below.

> *g) Please comment on the implications of each scenario, identify a preferred scenario or an alternative scenario. Please provide a rationale for any preferred or alternative scenario identified.*

Reauthorization and extension of RAM may serve one or more distinct but non-exclusive purposes. RAM can be used to meet or contribute toward procurement targets based on:

- *Operational needs defined in the LTPP,*

- *Legislative mandates such as defined in the RPS,*
- *Policy goals such as the Governor's Distributed Generation Initiative, or*
- *Supplier development and competitive market maintenance in line with RAM's original intent.*

Each scenario below offers different effectiveness in meeting each of these purposes.

i) Reauthorization with no change in terms: The Commission authorizes an additional 1,000 MW of capacity, for an additional 2 years, with 4 auctions held over the 2 years.

The Commission should authorize, at minimum, an additional 1,000 MW of capacity for 4 auctions over 2 years. Maintaining an active supply market is important in meeting future procurement needs. Due to the inherent barriers to participation in the RFP solicitations as currently conducted, unless and until RAM is replaced, it serves as the sole effective procurement path for 3-20 MW projects. A regular predictable minimum rate of procurement is required to maintain an available supply of projects, especially in light of the often multi-year interconnection process for projects to meet Phase I or proposed Phase II eligibility criteria and the Commissions efforts to ensure that inactive projects do not remain in the interconnection queues. Continuing RAM with a minimum procurement requirement is appropriate in light of these considerations, with additional procurement authorized based on its ability to meet operational needs and policy targets.

An economic analysis can be performed to determine the likely relative ratepayer benefit of increased competitive market participation against the cost of advancing the procurement schedule where no net shortage is being addressed. Given that the actual levelized cost of energy (LCOE) from RAM projects is already lower than CEC estimates[4] for the LCOE new CCNG gas facilities, modest regular minimum incremental procurement is unlikely to result in higher future energy costs, although portfolio balance must be considered.

[4] California Energy Commission, Cost of Generation (COG) model estimates for combined cycle natural gas facilities commencing delivery in 2015. The 20 year LCOE, including transmission charges, is greater than $150/MWh for CCNG facilities.

ii) *Reauthorization reflects assessment of need, cost and value of procuring a specific resource: The Commission authorizes additional capacity and timelines for solicitations based on need determination and authorization through the annual RPS Procurement Plans, and RAM is dispatched for procurement via one of the three scenarios listed below:*

a. *RAM held separately from annual RPS RFO;*

While this allows more frequent and staggered procurement than if combined with the RPS RFO, this scenario offers no assurance of any quantity of procurement and appears to prevent RAM projects from competing against RPS RFO resources.

b. *RAM is utilized as the primary procurement mechanism for all RPS-eligible procurement, unless an IOU requests a large-scale RPS RFO through its annual RPS Procurement Plan;*

RAM provides streamlined participation and selection for projects provide significant advantages over RFO projects; these factors weigh in favor of utilizing RAM over RFOs for all RPS-eligible procurement. It is important to utilize streamlined application processes and efficient, transparent and predictable selection criteria to support efficient markets and reduce costs for all parties.

However, RAM projects have additional benefits when compared with RFO projects. In addition to the resource planning, locational and environmental benefits discussed above, RAM projects currently have the benefit of having a clear path to completion within 24 months. Projects with near-term completion dates have more value than projects with later completion dates because such projects are less speculative and also because renewable project costs are projected to continue to decline provided that California maintains a steady and active market for such projects.

We offer qualified support for this as the best choice among the suggested scenarios, provided that all projects that participate in RAM are subject to the locational value criteria detailed in section 2 below and the environmental criteria cited by the NRDC and other parties, and provided that all projects must be completed within 24 months, subject to delays out of the developer's control.

We recommend our preferred alternative scenario below. In either case, improved screening or accounting for lowest total net ratepayer cost, rather than just the wholesale price bid, would make all selection processes more effective.

> *iii) RAM is utilized as a procurement option within the annual RPS RFO for streamlined procurement of a specific resource below a certain size.*

While this would be effective in utilizing the RAM pool to procure projects of a specific size, the scenario appears to limit utilization of the RAM mechanism or RAM projects from competing against larger resources, while also restricting procurement to a single annual event. Once-a-year solicitations contribute to boom and bust cycles in project planning, interconnection and bid applications, especially for projects on tight development timelines defined by RAM, with little or no opportunities the rest of the year.

A Preferred Alternative Scenario would best address the opportunities and limits defined above.

> *iv) RAM is included as a procurement source for all eligible generation, with minimum semi-annual procurement maintained at current levels to ensure predictable market participation.*

While some procurement may be limited to 3-20 MW projects participating in RAM, RAM projects would also be included in competition with bids in RPS and other RFOs where they otherwise met the eligibility criteria.

RAM provides a ready pool of defined projects meeting established eligibility criteria at individually bid prices. Bids received in RAM have been competitive against RFP procurement for not only RPS and even against longer-term conventional generation bids. Allowing developers to offer a single bid for RAM and all procurement solicitations greatly streamlines the bidding process for applicants and can increase the number of competitive bids available for RFO solicitations, whether RPS or conventional.

Failure to make use of a lower priced or better situated project that is available in the RAM queue simply because it did not submit a separate bid in to an RFP would result in ratepayers not receiving the lowest cost best fitting result.

When transmission related costs and other factors are fully accounted for, including Transmission Access Charges (TACs), capacity use, transmission upgrades, losses, congestion charges, and other costs passed on to ratepayers, procuring distribution connected generation serving local loads can provide ratepayers with the highest value. Consideration of these factors in improved bid equalization will identify many RAM projects as even more competitive and ratepayers are better served by such comparative full cost accounting on a level playing field.

2) RAM Program Elements

> *a) The RAM program originally required that projects be located in the service territory of PG&E, SCE, or SDG&E based on the reasoning that limiting eligibility to the utilities' service territories would help ensure that RAM projects efficiently utilize the existing distribution system. In December 2012, SDG&E filed Advice Letter 2437-E, seeking to modify the RAM project location requirements to allow projects located in the Imperial Irrigation District (IID) and interconnecting to the CAISO directly or via pseudo-tie to participate in the program. At the time of the issuance of these questions, the Commission has not yet taken action on SDG&E's Advice Letter.*
>
> > *i) Question: Based on the response to question (1.a) on the purpose of RAM, please comment on whether the RAM program would benefit from a modification to the locational eligibility requirement. Please comment specifically on the scenarios below:*

The purpose of incorporating eligibility criteria in RAM determines their appropriate application. As discussed below, the Commission established locational eligibility in order to avoid incurring additional ratepayer costs while maintaining a price-only project selection criterion. We argue that if simply selecting based on cost, the actual price paid by ratepayers should, in addition to the wholesale energy price, at least recognize any transmission charges incurred in delivering that energy to the customer[5]. However, none of the locational eligibility proposals reasonably accurately address the relationship between where energy is delivered, where it is generated, and the resultant costs.

To achieve the goals identified for establishing locational eligibility in the prior Decision (avoiding incurring additional costs while maintaining a price-only project selection criteria), it is insufficient to rely upon broad locational criteria merely requiring siting within the combined IOU service territories. While the current locational criteria, when combined with the project size limits, increases the likelihood of projects serving local loads and thereby avoiding using limited transmission capacity or incurring associated charges, it fails to ensures this or account for significant differences in locational value. Restricting eligibility to distribution level interconnection within the service territories would improve the effectiveness of the locational criteria and be the closest simple locational proxy in support of price-only selection.

The primary reason not to make any changes in the eligibility or selection criteria is that this may be seen as changing the rules on proposals that have already been developed at considerable expense. This is a significant factor that the Commission should take into consideration; however, the full initial planned and authorized procurement under the existing rules is being completed, and new procurement may reasonably expect modification.

Specific Scenarios:

1. *Expanded to entire CAISO control area.*

This expansion potential incurs wheeling charges between utilities that must be accounted for and may exacerbate geographical concentration of development, adding

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[5] RAM has already adopted a simple bid equalization formula to account for the impact of ratepayer reimbursed transmission upgrade costs. <u>The Clean Coalition supports such bid equalization and strongly recommends that additional and more significant ratepayer incurred transmission costs and charges also be included in the existing bid equalization process</u>.

to future transmission capacity costs and reliance on vulnerable transmission infrastructure.

2. Expanded to all of California.

This expansion potential incurs wheeling charges between utilities that must be accounted for, and may exacerbate future transmission capacity costs between Balancing Authorities, increasing reliance on transmission infrastructure.

3. Expanded to the transmission network within the Western Electricity Coordinating Council service area.

As noted in the Decision, incorporating WECC wide projects adds firming and shaping costs, in addition to those factors noted above.

4. Limited to project interconnecting to the distribution system in PG&E's, SCE's, or SDG&E's service territories only.

We support this scenario. Distribution interconnection was a substantial focus in establishing the 20 MW size limit in RAM. Distribution interconnected projects have been proven to be price competitive against transmission interconnected projects in RAM contracts awarded even before consideration of locational values. However, distribution interconnection does not ensure that projects will serve local load or otherwise be strategically located for ratepayer benefit.

Connecting on the distribution system and serving local loads avoids all transmission related costs for ratepayers. If transmission delivery and other locational factors were included in bid equalization, projects connecting to the distribution system would likely have garnered all contract awards.

The Commission should remain cognizant of potentially significant different impacts for SDG&E's smaller service territory that offers more restricted siting opportunities, although this factor may be irrelevant if the value of avoided delivery costs and other locational factors are included.

The Commission adopted RAM with goals including eliciting the "lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure" (D.10-12-048, p.2)

> "RAM eligibility should be limited to the utilities service territories. RAM provides a specific and well-defined value to ratepayers because small system-side RPS projects that connect to utility service territories incur none of the additional costs associated with some other forms of renewable generation. For example, these expenses may include costs to construct new transmission lines for more remote generation facilities and the expense of firming and shaping transactions for generation that can not be delivered directly to a CA balancing authority area. If projects located outside IOU service territories were included in RAM, then the price-only project selection criteria may not be applicable. Instead, IOUs may have to add transmission and/or firming and shaping adders to the market valuation of bids to evaluate the projects on an apples-to-apples basis. Thus, RAM enables more streamlined RPS program administration by requiring bid evaluation based on price only, which does not allow for other qualitative adders which are used to assess and rank bids' value in the annual RPS solicitations." (D.10-12-048, p. 41)

The Clean Coalition agrees with the intent of the Decision; however, limiting facilities to the IOU service territories does not actually result in an effective evaluation based on price only, as very different transmission impacts and charges may result, including unequal Transmission Access Charges (TACs), congestion, and consumption of transmission capacity (accelerating the timeline and capital requirements for future new capacity). The Decision did already acknowledge a need to consider one differential ratepayer transmission cost impact and apply bid equalization in the existing RAM with regard to bids connection to the transmission system, but missed the others that are of equal or greater significance.

We strongly support the goal of both streamlined program administration and predictability of bid evaluation for applicants. Costs associated with factors such as transmission usage can commonly increase the ratepayer cost of delivered energy by 30% or more. Bid equalization to account for such factors can be applied in a manner that is clear, predictable, and appropriate for streamlined bid evaluation. We discuss this further in response to Question 2e below.

> *ii. Question: If the eligible project location was expanded or limited, would the project ranking criteria need to be adjusted to capture additional costs/benefits specific to projects with these characteristics?*

Yes, per immediately previous response.

> *b. Question: Based on the response to question (1.a), please comment on whether the eligible project size for the RAM program should be adjusted from the current 3-20 MW requirement.*

While RAM has awarded PPAs to projects across the range of eligible capacity, the current selection process has heavily favored larger projects, severely limiting the effectiveness of the program in utilizing smaller resources that may offer significant advantages. This would be remedied by improved bid equalization to account for a more accurate comparison of the ultimate ratepayer cost of energy delivered to the consumer from each project. Such equalization is more appropriate and a better value for ratepayers than simply changing the eligible size. Improved bid equalization to reflect the full costs and value of projects will level the playing field while allowing the greatest flexibility for projects to optimize their size and location.

> *c. One of the goals of the RAM program was to reduce the transaction costs associated with the procurement of smaller renewable projects. Since the initial authorization of the program, the Commission has authorized IOU requests to transfer portions of IOU PV*

program capacity allocations to the RAM program to reduce the number of programs that are targeting the same renewable market segment.[6] *The following allocations of unsubscribed capacity remain in the utility owned generation (UOG) and independent power producer (IPP) portions of the PG&E and SCE PV Programs:*

IOU	Remaining
PG&E	252
SCE	100

c) Question: Please comment on whether the renewable market, the utilities, regulators, and ratepayers would benefit from further consolidation of the utilities' unsubscribed PV program capacity allocations into the RAM program.

Program markets that were developed by these other programs should be respected and not changed mid-course. The unsubscribed IPP portions of the SCE SPVP and PG&E PV programs approved with stated allocations of 50 MW each for a 5 year period should not be allowed to be terminated and included in the RAM allocations of each utility. Otherwise, the 1-3 MW projects that were developed in reasonable reliance on such programs will have no avenue for procurement. Such action would send a negative signal to the market that California programs aimed at specific market segments may be terminated without compelling reasons at any time.

SCE was properly and timely ordered to keep their IPP portion operating according to the CPUC rulings for 2013. PG&E on the other hand has been allowed to not initiate the 3rd IPP PV program in 2013 as required by the program while awaiting a ruling on the program termination. Allowing PG&E to move MWs from the IPP program to RAM would not only result in stranded projects but would also send a negative signal to

[6] D.10-12-048 initially authorized 1,000 MW. This capacity authorization was subsequently increased by D.12-02-002 (which authorized the transfer of 74 MW of capacity from SDG&E's PV Program to the RAM Program), D.12-02-035 (which authorized the transfer of 225 MW of capacity from SCE's PV Program to the RAM Program), and D.13-05-033 (which authorized the transfer of 31 MW of capacity from the UOG portion of SCE's PV Program to the RAM Program).

market participants, indicating that California programs aimed at specific market segments may be terminated without compelling reasons at any time.

The market segments stated to be served by those programs included projects in the 1-3 MW size for the PG&E program and 1-2 MW for the SCE program. Since RAM excludes projects under 3 MW, transferring program allocation to RAM would remove the entire procurement allocation for the projects smaller than 3 MW. These projects would only be allowed to participate in the Re-MAT program, which is operating with a cap of only 5 MW in each period. This would result in dozens of stranded projects, or projects subject to major delays if future capacity is added to Re-MAT. These delays will push procurement beyond the expiration of federal incentives, resulting in higher costs for ratepayers.

Consistent and predictable procurement demand is important to attract investment and establish long-term business presence and experience. As is clearly evidenced in other regions, costs are driven down when the scale of the market provides efficiencies gained through experience[7], and where demand is sufficiently large and consistent to warrant competitive investment in greater efficiency. Delaying procurement will depress market interest and development, eroding California's national leading position in market investment and innovation. These factors weigh strongly in favor of keeping the Solar PV Program procurement to the original schedules and criteria defining the intended market development.

i) Question: How does the recommendation align with the response to questions (1.a) and (1.c)?

This recommendation is consistent with such responses. Maintaining market predictability and reasonable continuity of demand is important for long-term development of competition and efficiency.

[7] Seel, J., Barbose, G., and Wiser, R., Sept 2012 'Scoping Analysis - Why Are Residential PV Prices in Germany So Much Lower Than in the United States'. Lawrence Berkeley National Laboratory. DOE Contract No. DE-AC02-05CH11231

d) D.10-12-048 required each IOU to make an upfront determination of the types of products (peaking, non-peaking, baseload) the utility intends to procure. The Commission adopted this requirement to ensure that procurement was consistent with portfolio need and to provide the market with clarity and certainty on the opportunities provided by RAM.

Question: Please comment on whether these product category distinctions and requirements should be maintained or adjusted. Please reference the response to question (1.b.):

We do not have any recommendations at this time.

e) RAM bid evaluation and selection is limited to the levelized post-TOD price ($/MWh) with adjustments for transmission network upgrade costs and resource adequacy benefits.

i) Question: Should any other resource valuation factors be included in the project ranking value? For example, should congestion costs be included in the bid ranking methodology?

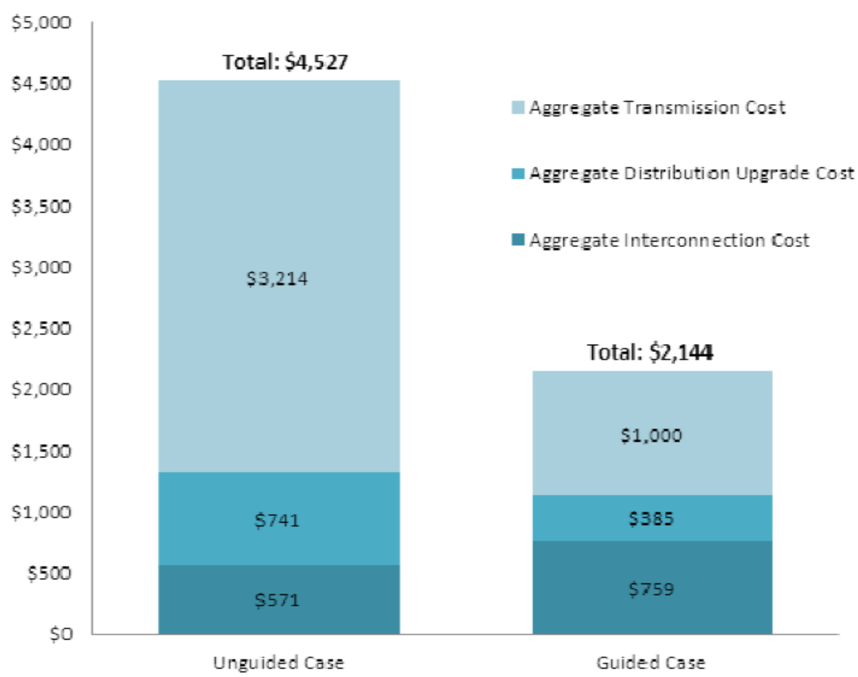
Yes, a full cost and value accounting approach should be applied to the extent practical within a streamlined evaluation process. As discussed further below, this should include at least those transmission related costs that can be clearly defined and identified for applicants in advance, including Transmission Access Charges, average line losses, average avoided future transmission capacity, and regional or nodal specific avoided congestion value.

ii) Question: If proposing additional resource valuation factors please present and explain the methodology for calculating the specific factor.

The Clean Coalition recommends use of the methodologies described below to efficiently incorporate the following additional locational benefits into the bid equalization process for RAM: avoided Transmission Access Charges, avoided future Transmission Access Charges, avoided line losses, and local capacity value.

Such locational values represent billions of dollars worth of potential ratepayer savings. A May 2012 study by Southern California Edison found that transmission upgrade costs for their share of the Governor's goal of 12,000 MW of distributed generation could be reduced by over $2 billion from the trajectory scenario. The lower costs were associated with the "guided case" where 70 percent of projects would be located in urban areas, and the higher costs were associated with the "unguided case" where 70 percent of projects would be located in rural areas.[8]

Figure 1: Integration Costs for Distributed Generation



[8] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012

Source: Southern California Edison[9]

The Clean Coalition continues to urge the Commission to add locational factors to the RPS LCBF methodology, and to other procurement decisions. Limited implementation of bid equalization was established in RAM to account for ratepayer costs associated with reimbursed transmission upgrades, and the time is ripe for additional consideration of locational value in this proceeding.

The ratepayer costs and benefits accruing from location have been described by the Commission as Locational Benefits and should be considered for RPS procurement under section 399.13(a)(4)(i-vi) of the California Public Utilities Code. Subsections (i) and (ii) both implicate the costs – and necessarily the benefits – of integrating RPS resources into the grid. Evaluating the costs of "transmission investments" (per section (i)) and "the cost impact of procuring the eligible renewable energy resources" (per section (ii)) requires a fuller consideration of locational value in terms of grid usage and deferred grid upgrades, especially when compared to wholesale generation connected directly to the distribution grid closer to load. In addition, location can have a very significant impact on both project viability (subsection iii), particularly regarding areas subject to transmission constraints and related uncertainty in interconnection schedules and costs, and on workforce factors (subsection iv) as the state seeks to consider income, employment levels, and investment distribution in procurement, as discussed in the 2011 Integrated Energy Policy Report. Only by fully assessing the ratepayer costs and avoided costs associated with location can bids be adequately evaluated with respect to other projects ("rank ordering and selection," per section 399.13(a)(4)(A)).

During final development of the related SB 32 implementation, Commission staff proposed a detailed locational adder, based on an analysis by E3,[10] as part of the price to be paid to developers under ReMAT. The final decision (D.12-05-035) opted, however, to delay including a locational adder until further study was completed.

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[9] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012

[10] http://www.cpuc.ca.gov/NR/rdonlyres/90AA83C6-1AAC-4D7E-966E-299436C4A6BD/0/E3FITAvoidedCosts9262011.pdf

With the review of RAM procurement now beginning, it is the time to resume this consideration of locational value, at least with respect to the more easily assessed transmission factors such as Transmission Access Charges (TACs), transmission capacity value, deferred transmission upgrades, line losses, and Local Capacity Requirements (LCR). While the prior discussion in SB 32 contemplated a "locational adder" that would be offered to projects based on their location, we are not recommending a payment, but rather bid equalization to ensure that ratepayers are served by energy at the lowest delivered cost after delivery charges are considered.

Avoided Transmission Access Charges

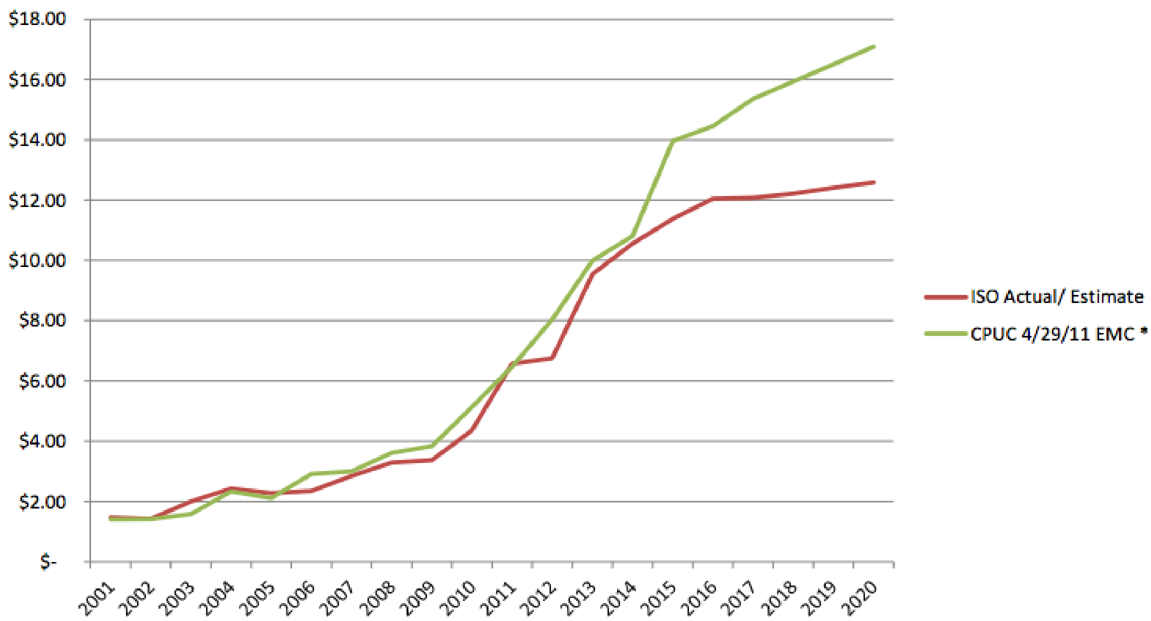
While specific additions or upgrades to the transmission system that are required to accommodate individual projects are considered in evaluating the relative cost of projects, this fails to capture the full transmission delivery cost of projects. The use of valuable existing transmission infrastructure is also required, increasing congestion and using up capacity, ultimately contributing to the need for more transmission investment in the future.

Transmission related costs of delivering energy from remote generation are often combined into costs that are charged by the transmission operators. In California, these costs are called Transmission Access Charges (TACs). This is a flat "postage stamp" fee for every kWh delivered to the distribution system from the transmission grid. TACs are avoided by energy that is delivered directly to the distribution system to serve loads on the same substation.

The High Voltage TAC is currently charged at $8.86/MWh and is consistent throughout the CAISO system. The Low Voltage TAC applies to the CAISO operated portion of systems within each individual utility service territory. For PG&E, the use rate charged is currently $6.057/MWh, resulting in a total 2013 charge of $14.92/MWh (1.492¢/kWh). While the threshold definition of sub-transmission voltage and ISO operation varies between utilities, comparable cost allocation occurs either through ISO charges or internal utility accounting.

TAC rates have increased at an annualized rate exceeding 15% since 2005 as new transmission dependent generation has been approved, and new transmission capacity is far more costly than maintaining existing capacity. CAISO mid value estimates for the rate of increase in TAC charges will be substantially less than the recent trend and prior CPUC estimates, as illustrated below. Utilizing CAISO's current projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, the levelized current value of avoidable TAC charges applicable to a 20 year distributed generation power purchase agreement is 2.4¢/kWh.

Figure 2: Historical and Projected High Voltage Transmission Access Charges ($/MWh)



Source: CAISO 2012[11]

The Clean Coalition recommends the following test for assigning avoided TAC costs to a specific project in the bid equalization process. Any portion of the generator's output that is below minimum coincident load (MCL) at the substation level will not utilize the transmission system, and therefore should be credited for avoided TAC costs. Any portion of the generator's output that is above MCL at the substation level will be deemed to backfeed to the transmission system and will not be credited for avoided TAC costs.

For example, if 90% of the output of a generator falls below MCL, and 10% of the output is above MCL, then the 10% of the output would be presumed to backfeed to the transmission system and would be associated with TAC charges. The project would be associated with the additional value of avoided TAC charges and avoided future TAC rate increases for 90% of its output over the course of its 20-year contract.

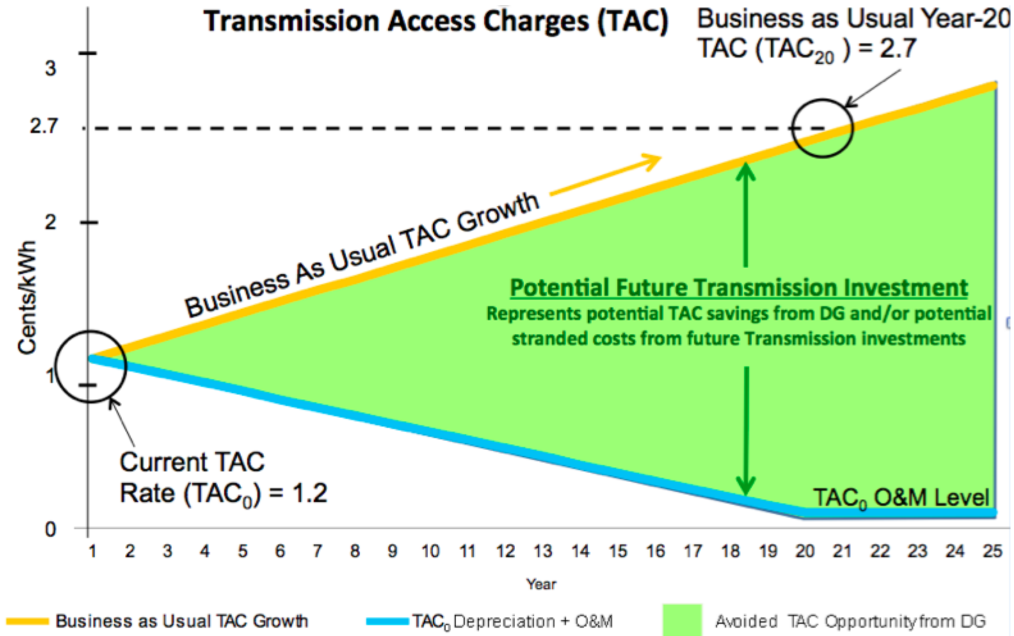
Transmission Access Charges specific to each utility are calculated by CAISO each year. This data is publicly available and more accurately reflects the locational value than may

[11] http://www.caiso.com/Documents/BriefingLong-TermForecastTransmissionAccessCharge-Memo-Nov2012.pdf

be currently practical in assessing distribution impacts. In short, TACs are specific charges applied to each unit of energy only where it is delivered through the transmission system, and represent very good proxy for significant avoided transmission costs. Ideally, projects would be compared based on the value of existing infrastructure used for delivery of energy, even if only on a per MW mile or per MW standardized basis. At the very minimum, differentiation should be made based on the assessed delivery charges borne by ratepayers for both high voltage (HV) and low voltage (LV) transmission, as reflected in TACs or, in the case of SCE's own LV system, a comparable charge. For example, when comparing a project with energy deliveries incurring both HV and LV TACs against one serving regional load using only low voltage transmission, the difference in delivered energy costs for ratepayers is currently about $8/MWh.

<u>Avoided future TAC Rate increases on all transmission dependent energy</u>
Deploying distributed generation projects that displace transmission sourced energy during peak demand periods avoids the need to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission – both of which reduce future TAC rates, as reflected in the diagram below.

Figure 3: Clean Coalition estimate of TAC increases



Source: Clean Coalition, 2012

The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate additional remote generation. The blue line represents the decrease in TACs that is possible if that net additional remote generation was entirely replaced with distributed resources (the down ramp is based on a 40-year average depreciation schedule for TACs-related assets like transmission lines). Thus, the green wedge represents the potential cost savings achieved with distributed resources and continued operation of existing transmission capacity.

Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity, slowing the growth in TAC rates that is driven by the need to recoup new investment costs. Reducing the need for new investment in transmission will reduce charges across the board for all energy utilizing the system in a Merit Order Effect.

Transmission costs vary widely between projects, but if an average figure of $1 million is used as the marginal cost per megawatt of new transmission capacity, the savings are seen to accrue rapidly. While existing transmission will still be broadly utilized to supply energy during hours in which local intermittent DG is not available, even intermittent DG can offset its full generation capacity in new transmission capacity required for peak annual transmission loads.

With approximately $20 billion in planned future investments, 1 gigawatt of aggregated avoided new transmission capacity resulting from procurement of DG represents a 5% reduction in the basis for future TAC rates, or 0.005% per fully qualifying MW. Taking a levelized 20-year TAC rate of 2.4¢/kWh, a 0.005% reduction results in a savings of 0.0012¢/kWh. This appears a very small number, but this savings would be realized by virtually all of the 254,000 GWh[12] consumed within CAISO transmission system electricity by 2020 which is subject to TAC charges. These Merit Order cost savings in TAC charges at 0.0012¢/kWh would equal $30,540 in annual CAISO wide ratepayer savings for each MW reduction in required transmission capacity, assuming a 1:1 peak annual capacity reduction. Applied to a DG PV output of 1,500 MWh/MW/yr, this results in an added ratepayer value of 2¢/kWh. While the applicable transmission capacity reduction will depend on CAISO projected relationship between the generation and peak demand profiles, the value of avoided future transmission capacity cost is too large to ignore.

As the CAISO evaluates transmission requirements and costs under the approved CPUC resource development scenarios, including the High DG/DER scenarios, in the Transmission Planning Process, values associated with both general peak load reduction and specific regions can be clearly established. Historical values may be recognized through review of CPUC approved transmission procurement and transmission costs identified in each utility's rate base.

<u>Local Capacity Value</u>

Local capacity value may be determined based on the current methodology for establishing capacity charges for Load Serving Entities within the CAISO system.

<u>Avoided line losses</u>

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[12] California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, Mid Energy Demand

Average transmission losses are tracked by CAISO for each regional transmission zone and average 3% statewide (with the exception of the LA Basin).[13] Losses also occur on the distribution system, averaging 3%, and proportional to the distance between energy supply and load. Where generation is located in closer proximity to load, these losses may also be reduced. System wide losses are substantially higher due to congestion factors during peak demand periods, averaging approximately 10%, and time of delivery differentials should be recognized.[14] Losses for each applicable section of grid utilization should be considered. Projects located close to actual load served will avoid all transmission and significant distribution losses.

The inclusion of locational factors in the selection process will result in ratepayer savings, making RAM a more efficient allocation of ratepayer dollars. Standardized values based on the methodologies described above may be applied to efficiently manage the process of bid equalization during procurement evaluation.

iii) Question: If proposing additional resource valuation factors, comment on their consistency with Least-Cost Best-Fit and whether the addition of these variables would compromise the goal of having a streamlined bid submission and valuation process.

The cost of delivery and other costs ultimately incurred by ratepayers should be added to the bid value to incorporate the total procurement cost for valid comparison in compliance with the "total cost basis" regulatory language establishing LCBF methodology. This should include HV and LV transmission charges, and line and congestion losses, which can be a significant factor in determining the delivered cost of procurement, adding $24/MWh for transmission charges alone levelized over a 20 year contract term relative to generation connected directly to the distribution system.

The Clean Coalition is strongly supportive of utilizing and improving the Least Cost, Best Fit (LCBF) methodology in conformance with Public Utilities Code section 399.13(a)(4) which states in part: "The commission shall adopt, by rulemaking, all of the

[13] CAISO, *2012 Local Capacity Technical Analysis Final Report and Study Results*, April 29, 2011
[14] Table ES-1: Comparison of Loss Factors, *A Review of Transmission Losses in Planning Studies*, August 2011, California Energy Commission, CEC-200-2011-009

following: (A) A process that provides criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources to comply with the California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall take into account all of the following: (i) Estimates of indirect costs associated with needed transmission investments and ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources." (Emphasis added.)

We have recommended above (and detailed in testimony[15]) predictable, transparent and easily applied additional bid equalization factors that support determination of the total cost basis of competing bids. Recognition of the true cost and value of projects rewards the actual lowest cost products, improving both selection fairness and ratepayer value. Any addition to the evaluation procedures will marginally reduce their speed and simplicity, and standardized values or proxy criteria can be employed in a predictable and transparent manner to limit any additional evaluation burden during the applicant's initial project feasibility planning, after initial interconnection review, and in both initial and final bid selection. The value of recognizing significant cost factors vastly outweighs the burden of something as simple as checking the cost of delivery before purchasing a product.

f. Question: Aside from actual bid evaluation criteria, are there other ways the bid submission and evaluation process could be streamlined on the developer or the IOU side? For example, is there a price threshold for submitted bids above which the IOUs would not need to conduct a complete offer eligibility screening?

We agree that reducing eligibility screening for bids that are above a reasonable price may avoid unnecessary effort. This threshold must be sufficient to ensure that adequate capacity will be filled and it is essential to consider bid equalization factors to the apparently lower range bids prior to establishing any such price threshold. We invite the IOUs to offer recommendations based on their statistical evidence regarding the value of applying such a screening threshold. At the same time, an applicant deserves either

[15] Proceeding A.12-01-008 and A.12-04-040, Exhibit CC-01: Prepared Testimony of Kenneth Sahm White regarding locational valuation for the Green Tariff Shared Renewables programs.

equal treatment or compensation if they do not receive the benefit of eligibility confirmation.

<u>3) RAM Eligibility and Viability</u>

a. D.12-10-048 stated that utilities should identify in their bid protocols the criteria for determining whether a developer has subdivided a project in order to circumvent the program's 20 MW eligibility requirement. This directive served to reduce the potential for seller concentration resulting from a seller winning all of the contracts in a utility's auction by subdividing a larger project. The IOUs subsequently established seller concentration limits by capping the amount of capacity a single seller could be awarded in each auction.

> *i) Question: Should subdivided projects be eligible to participate in RAM? If so, should there be specific requirements on how subdivided projects may be bid?*

No, subdivided projects should not be eligible to participate in RAM – subdividing projects conflicts with the fundamental goal of providing a distinct market opportunity defined by project size. Larger projects may compete in RPS solicitation based on need determined in that proceeding and should not be allowed through subdivision to reduce the procurement otherwise established explicitly for the sub 20 MW market.

> *ii) Question: What are the appropriate technical criteria for determining whether a project is a standalone project or a subset of a larger project?*

We have no recommendations for changes to the existing criteria at this time

b. The RAM program has a defined set of project viability requirements, which include: demonstration of site control, demonstration of developer experience, deployment of commercialized technology, demonstration of completion of a System Impact Study, completion of a Phase I interconnection study or having passed Fast Track screen under the Wholesale Distribution Access Tariff Small Generation Interconnection Procedure or the Fast Track screen *under the CAISO Generation Interconnection Procedures, and the ability for the project to be operational within 24 months of contract approval.*

> *i) Question: Please comment on whether the existing RAM Program viability requirements are adequate or whether adjustment should be made (e.g., add completion of a Phase II interconnection study).*

The project viability requirements are a delicate balance between uncertainty in procurement and costly or restrictive hurdles to eligibility. Where adjustments are made, the effort should favor improving predictability without increasing costs or requirements, which are already substantial and had unwanted side effects. For example, interconnection eligibility requirements push far more projects into the interconnection queues than will ever receive PPAs leading to development, hindering the study process and leading to unreliable study results. Requiring projects to have completed Phase I or equivalent interconnection studies not only requires significant sunk investment that results in higher average transactional costs per unit of energy procured but may also limit the active field of bidders leading to bidder concentration.

The relatively short timeframe for development serves to effectively identify procurement failures quickly, with little risk of significant shortfall. Rather than increasing the eligibility requirements, the Commission should first consider warranted adjustments in development milestones. Project viability scoring is another option that could be incorporated in bid equalization, although transparent, predictable and effective scoring may prove challenging.

> *ii) Question: If they are not, please provide recommendations on adjustments to the criteria and a rationale for each proposed adjustment.*

The Clean Coalition recommends that the Commission both define the criteria for establishing site control and approve standard forms for proof of site control.

The RAM decision did not clearly define criteria for establishing site control. Developers have faced inconsistent and onerous requirements, resulting in confusion, additional costs, and many months of delay to establish eligibility. Developers have experienced rejection of binding letters of intent or written options to enter into purchase or lease agreement.

We recommend that the Commission approve a standard form of proof of site control based on the form used by the Los Angeles Department of Water and Power for its solar feed-in tariff program, attached to these comments as Exhibit A. Since it is not financially feasible for a developer to execute a real property lease or purchase agreement before the power purchase agreement has been secured, we recommend that a written option to purchase or lease the property be deemed sufficient to demonstrate site control. It is also appropriate to require a developer to have entered into a lease or purchase agreement within 60 days of having entered into both a power purchase agreement and an interconnection agreement.

4) RAM Contract Terms and Conditions

a. Question: Are the terms and conditions of the IOUs' standard RAM contracts adequate for the RAM Program as currently implemented?

i. Please provide redlines to the standard contracts as well as a matrix proposal of changes to the standard contracts, identifying the current term, the proposed term and the rationale for the proposed change.

The Clean Coalition has previously submitted a simplified PPA and a matrix of proposed changes and rational appropriate to reduce the burden on smaller facilities in the ReMAT proceeding. While the larger RAM projects may also benefit from some changes, the current PPA has not proven unworkable to our knowledge.

b. Question: Can the terms and conditions be modified to better support the Commission's safety objectives?

We have no recommendations at this time.

c. Question: Is there a way to streamline the standard contract adjustment process?

We have no recommendations at this time.

d. Question: Is there a subset of terms and conditions that the Commission should allow IOUs to modify without prior commission approval?

The Clean Coalition is not opposed to this in principle. However any such changes in terms and conditions should conform to pre-established and approved limits or range of possibilities established through this proceeding.

Respectfully submitted,

/s/Kenneth Sahm White
Kenneth Sahm White
Economics & Policy Analysis Director
Clean Coalition

/s/Stephanie Wang
Stephanie Wang
Policy Director
Clean Coalition

Dated: January 31st, 2014

Proof of Site Control Form

Please complete all fields on this form and check the applicable site control option below.

I, ______________________________ ("Site Representative"), representing ______________________________ ("Site Owner"), attest that ______________________________ ("Applicant"), has Site Control in the manner indicated below, of assessor's parcel number: ________________ located at ______________________________ ("Property"). The Applicant has dominion over the Property to the extent necessary to construct, own and operate the __________ kilowatt (kW) ______________________________ ("Project") in accordance with an executed Standard Offer Power Purchase Agreement ("SOPPA") with Los Angeles Department of Water and Power ("LADWP").

In this case, Site Control means (check one applicable item below):

___ Applicant holds title to the Property.

___ Applicant has a duly executed contract for the purchase of the Property.

___ Applicant has been granted a valid written option, unconditionally exercisable by Applicant, to purchase the Property at a pre-determined price upon executing a SOPPA with LADWP. (The option is binding on the Site Owner of the Property and the Site Owner cannot unilaterally withdraw, revoke, or rescind the obligation to sell the property to the Applicant.)

___ Applicant has a duly executed contract for the lease of the Property. (The lease unconditionally binds the Site Owner, subject to payment of a named rent and compliance by the Applicant with standard commercial terms.)

___ Applicant has been granted a valid written option, unconditionally exercisable by Applicant, to lease the Property for a pre-determined rent upon executing a SOPPA with LADWP, for a duration of no less than the term of the SOPPA, including rights to install, own, and operate the Project on the Property. (The option is binding on the Owner of the Property and the Owner cannot unilaterally withdraw, revoke, or rescind the obligation to lease the property to the Applicant.)

Signature ______________________

Print Name ______________________

Date ______________________

Notary

July 16, 2013 A3

Source: Attachment 3 of the LADWP FiT Guidelines Package (07_16_2013) available under the 'Set Pricing Guidelines Package' link at:
https://ladwp.com/ladwp/faces/wcnav_externalId/res-gogreen-FiT-100MW?_adf.ctrl-state=1admotflhp_38&_afrLoop=158384646956561