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

CLEAN COALITION AND CALSEIA PETITION FOR MODIFICATION OF D.12-05-035

Tam Hunt
Attorney for:
Clean Coalition
16 Palm Ct
Menlo Park, CA 94025
(805) 214-6150

November 12, 2012

CLEAN COALITION AND CALSEIA PETITION FOR MODIFICATION OF D.12-05-035

The Clean Coalition and CALSEIA respectfully submit this petition for modification pursuant to Rule 16.4.

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 enhance energy security.

To achieve this mission, the Clean Coalition promotes the vigorous expansion of Wholesale Distributed Generation (WDG) — a market segment defined by renewable energy generation that connects to the distribution grid and serves local load. The Clean Coalition drives policy change to remove major barriers to the procurement, interconnection, and financing of WDG projects. Furthermore, to enable higher penetration of clean local energy generation, the Clean Coalition drives policy innovations that support the deployment of Intelligent Grid (IG) market solutions — such as demand response, energy storage, and advanced forecasting.

CALSEIA is a non-profit trade association representing approximately 200 solar energy companies doing business in California. Its members include manufacturers and distributors of solar photovoltaic and solar water-heating equipment, but three-fourths of CALSEIA members are licensed installation contractors. CALSEIA's mission is to expand use of all solar technologies in California and establish a sustainable industry for a clean energy future.

I. The Commission should modify D.12-05-035 to create a viable and sustainable program

A. General points

Governor Brown has set a goal of 12 GW of DG by 2020. Unfortunately, the new SB 32 (Re-MAT) program is far too small to be meaningful to the Governor's goal. The Commission's allocation of capacity to the IOUs totals only about 200 MW when existing contracts under the prior AB 1969 program are subtracted from the IOU share of the total 750 MW program. The IOUs plan to issue their Re-MAT allocations over a four-year period starting in early 2013 and projects will take up to two or more years to construct. Accordingly, the new Re-MAT program may result in about 200 MW by the end of 2018, which is a tiny fraction of the Governor's 12 GW goal by 2020. When other programs are included, such as the California Solar Initiative and Self-Generation Incentive Program, a more substantial fraction of the 12 GW goal may be achieved, but still not more than a few GW. California clearly has a long way to go in terms of new procurement opportunities and policies for reaching the Governor's goal. Clean Coalition and CALSEIA make a number of recommendations herein that will allow the new Re-MAT program to become a larger part of the solution.

Additionally, despite staff recommendations to the contrary, D.12-05-035 ignores the fact that location matters. All parties agree that better siting of new generation makes a real difference in cost and value[1] and California is long overdue in capturing these locational benefits for both grid planning and procurement purposes. SB 1332 (2012), just passed into law, is the first law to explicitly require consideration of locational benefits, for publicly owned utilities implementing the feed-in tariff first enacted by SB 32. Despite the broad agreement over locational benefits, in concept, the Commission, in D.12-05-035

[1] For example, SCE issued a report in May, 2012: "The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System."

refused to either accept staff recommendations for providing locational value or to complete the additional work required to respond to IOU concerns about the staff-recommended methodology. This is clearly grounds for modification of the Decision and we discuss this concern below.

California and Commission policies should at this point aim to create a viable and sustainable market for clean energy deployment, particularly for Wholesale Distributed Generation (WDG), per the Governor's 2020 DG goal and the new market realities supporting smaller projects. We make a number of recommendations herein that will, if adopted by the Commission, do much to ensure that Re-MAT doesn't become another failed experiment and is, instead, the basis for a new paradigm for renewable energy development in California.

B. Recommended program design changes

1. Re-MAT program capacity is far too small to provide valid price discovery.

The primary flaw with the new program created by D.12-05-035 is its small size. SB 32 created a 750 MW statewide program, which includes IOUs and POUs. The proportionate share for IOUs, however, is diminished considerably by the pre-existing AB 1969 program, which consists of 478 MW for the IOUs. The new SB 32 allocation to the IOUs actually reduced the size of SCE's program (from 247.6 MW to 226 MW), while increasing PG&E's (from 209.2 to 218.8 MW) and SDG&E's (from 20 to 48.8 MW) only slightly. More importantly, after subtracting the existing AB 1969 contracts from the IOU share of the 750 MW, <u>the new Re-MAT will be only leave capacity for about 200 MW of new contracts, stretched over four years in 24 bi-monthly periods, not the 300 MW that the Decision suggests.</u>

This equates to a precise maximum of one 3 MW project per product type per utility for each bi-monthly period.[2] Here is the allocation from D.12-05-035, at the time of this petition, with updated numbers re AB 1969 contracts executed:

Utility	AB 1969 FIT contracted allocation (MW)	Re-MAT initial allocation (MW)	Re-MAT remaining allocation (MW)[3]
SCE	149	226	77[4]
PG&E	109	219	110
SDG&E	14	49	35
		Total	222

The Commission recently scoped a Proposed Decision on the Re-MAT Standard Form PPA and tariffs for first quarter 2013, which means that the program is unlikely to "go live" before April of 2013 – more than three years after SB 32 passed in 2009. The longer the Commission delays implementation of SB 32 the more capacity will be taken up by the existing AB 1969 program, which will result in even less than the 222 MW calculated above for the new SB 32 program. <u>It is likely, given recent uptake in SCE's AB 1969 program, that SCE's SB 32 allocated MW will be zero or near zero by the time that the SB 32 program is up and running in 2013</u>.

Assuming, however, that SCE's 12 bi-monthly periods in the initial 24-month program will have a capacity of 77 MW/12 periods /3 product types = 2.13 MW each. The first period for each product type must contain at least 3 MW. We have recommended that SCE and all the IOUs be required to allocate at least 3 MW to

[2] The program may also result in a higher number of smaller projects, but most projects will, at least initially, be the maximum size of 3 MW due to a likely cost advantage over smaller projects.
[3] Subtracting column 2 from column 3.
[4] Since this petition was originally drafted, SCE's available capacity has dropped from 77 MW to 68 MW due to additional AB 1969 contracts being signed.

each product type in each bi-monthly period. As such, the maximum that SCE will have in each product type in each bi-monthly period is one 3 MW project. Again, it is quite likely that SCE's SB 32 program will in fact have zero MW available by the time the program commences due to uptake in the AB 1969 program, making the Re-MAT moot for SCE unless the program is expanded.

Similarly, PG&E's 110 MW is reduced to 3.05 MW, or just one Re-MAT project, for each of the 12 bi-monthly periods (110 MW/12 periods/3 product types = 3.05 MW).

SDG&E's 35 MW allocation is reduced to 0.9 MW for each product type for each bi-monthly period after the initial 3 MW allocation (35 – 3 = 32, 32 MW /12 periods /3 product types = 0.9 MW), or just 11 total 3 MW projects if our recommendation regarding having at least 3 MW in each product type in each bi-monthly period is accepted.

Accordingly, each IOU will have a maximum of one 3 MW project for each product type in each bi-monthly period. One project every two months is clearly not an adequate market sample for an effective market-based pricing adjustment mechanism – which was the entire point of the Re-MAT mechanism as an alternative to the many options offered by parties like the Clean Coalition, Sierra Club, and others. Some additional market information will be obtained from parties in the queue who choose to deny or accept the offered bi-monthly price, even if they don't obtain the contract because of the very limited allocation. However, the very fact of such limited contract capacity in each bi-monthly period will result in the "race to unviability" that Clean Coalition discussed in its comments on the Proposed Decision and discuss further below. This means that parties in the queue will face a strong incentive to accept the price offered as soon as possible because of such limited program capacity, even if the price offered is ultimately too low to be financially viable for a reasonable project developer. Security deposits and other fees are required to obtain a PPA, and these will mitigate the race to unviability– but only partially. This is the case because the speculative hedged value of a 3 MW Re-MAT PPA may be worth far more than the security deposits or other potentially forfeited fees. Clean Coalition has observed over the last few years many developers accepting PPAs in various programs at prices that can't be financed. As a consequence, many PPAs are accepted and ultimately lead to project failure. This will surely happen, with even higher frequency, under the current Re-MAT because of the shortage of PPAs for a growing population of developers in California.

Clean Coalition, CALSEIA, and Sierra Club have advocated for various modifications for reducing the race to unviability but there is a fine balance to be struck between disincentivizing parties from accepting PPAs at prices that are unrealistically low and keeping the new program open to a diverse group of developers by avoiding fees that are too high. The deposits and fees should not be raised any higher because this would discourage all but the most deep-pocketed of developers, and this is clearly not the intent of SB 32.

The most effective solution for this potentially fatal problem (the race to unviability) in the Re-MAT design is to increase the program size. Clean Coalition and CALSEIA call again for the Commission to use its regulatory authority under the California Constitution and consistent with statute to double the capacity of the Re-MAT for the IOUs, from approximately 500 MW (of which only about 200 MW remains) to 1,000 MW. This will create a program with about 700 MW remaining for the IOUs and will allow three or four 3 MW projects (and more if projects are less than 3 MW) to be allocated for each product type in each bi-monthly period. This is still a relatively small program, considering the Governor's 12,000 MW goal for distributed generation in California, but doubling the program size will go a long way toward creating a market large enough for accurate price discovery, which is the intent behind the Re-MAT mechanism.

2. The program should allocate capacity within 12 months and not be stretched out to 48+ months.

A similar problem arises with the extended time period for the Re-MAT allocation to be fully contracted. The Proposed Decision prescribed 12 one-month periods for allocation of the full program capacity, with some potential for modification at the end of the program for unallocated capacity or canceled contracts. The Final Decision, however, changed this and prescribes an initial program of 12 <u>bi-monthly</u> periods, but with any canceled or unallocated capacity added to later months. PG&E interprets the Decision and suggests in their proposed tariff a second 24-month program, bringing the potential length of the program to as long as 48 months. 48 months to contract about 200 MW of capacity is a woefully slow, small and lengthy program given the state's goals for distributed generation This severely undermines the probability of success of the Re-MAT and the Commission should modify the Decision to take the Governor's goal of 12,000 MW of DG seriously.

The most effective solution to address the problem of a small and slow program failing to yield a robust market adjusting price is to both (1) double the program size, as recommended above (from 500 MW to 1,000 MW for the IOUs), and (2) to return to the Proposed Decision's 12 one-month periods for total program execution. Any unallocated capacity or contracts that are canceled during the 12-month program should be rolled into to the next month, and contracts that are canceled after the 12-month duration to a 13th one-month period, or later allocations if required. Alternatively, six two-month periods would also be a significant improvement over the current 12 two-month periods.

3. A price floor should be added to improve certainty and predictability

Re-MAT will, for the reasons described above, result in a “race to unviability.” In particular, the very small size of the program will heavily incentivize parties in the queue to accept a PPA at prices that are unrealistically low. Prices will start at 8.923 c/kWh but due to the fact that each product type will have a maximum of 3 MW (one project) in each bi-monthly period, it is practically guaranteed that this price will rapidly drop. That is, it will take only one party in the queue to accept a single contract for the price to decline in each bi-monthly period (as long as there are at least five different parties in the queue). Re-MAT prices will drop by a multiplying increment of 0.4 c/kWh, resulting in the following price drop if just one 3 MW contract is accepted in each bi-monthly period for the first six periods.

Bi-monthly period	Declining price (c/kWh)
1	8.923
2	8.523 (8.923 – 0.4 = 8.523)
3	7.823 (8.523 – 0.8 = 7.823)
4	6.623 (7.823 – 1.2 = 6.623)
5	5.023 (6.623 – 1.6 = 5.023)
6	3.023 (5.023 – 2.0 = 3.023)

3.023 c/kWh is clearly unrealistically low. It seems very unlikely that any parties will accept prices at this level, or even at 5.023 c/kWh, given current and reasonably expected renewable energy project economics in the next few years, but this table illustrates graphically how quickly the prices will drop under Re-MAT and how little it takes (just one contract signed for each product type) to induce price drops. Re-MAT will adjust prices upwards if no contracts are accepted or if less than 50% of the allocation is accepted in that bi-monthly period, as long as at least five developers are in the queue, which will probably result in some "yo-yo effects" for prices. This will have the effect of freezing the program during periods where the price lowers below the point of viability, contributing to program instability.

Doubling the program size and halving the length of the program will go a long way toward mitigating the race to unviability. We also recommend, however, that the Commission set a price floor to protect against parties being forced to accept a PPA at a price that is unrealistically low, to avoid the instability of the yo-yo effect, which will dramatically reduce program certainty for developers. A price floor will help to ensure that the program allocation is contracted in the first program period (24 months) and not delayed unconscionably. <u>We recommend a price floor equivalent to the second price drop (7.823 c/kWh)</u>. This level ensures that ratepayers are protected because this price is substantially less than the avoided cost for status quo technologies like natural gas (the current Market Price Referent for a 20-year contract and a project coming online in 2014 is 9.755 c/kWh). This level also provides market certainty for developers who will know that as long as there is unallocated capacity in the program the lowest price they will be forced to accept is 7.823 c/kWh. This would allow for advance planning and some additional certainty about the program, even though parties will still have a very small chance of obtaining a PPA because of the extremely small program size.

4. A locational adder should be included in the Re-MAT.

SB 32 states (Section 1(e), emphasis added)[5]:

> A tariff for electricity generated by renewable technologies should

[5] We note the FD also cites SB 32's Section 1 for legislative intent (p. 52): "We further point out that our policy guideline is grounded in the legislation [sic] intent set forth in SB 32 (Sec. 1) which emphasizes the importance of encouraging the location of clean generation close to load centers in order to meet increases in demand for electricity."

> recognize the environmental attributes of the renewable technology, the characteristics that contribute to peak electricity demand reduction, reduced transmission congestion, <u>avoided transmission and distribution improvements</u>, and in a manner that accelerates the deployment of renewable energy resources.

While the Staff Proposal recommended a methodology for capturing avoided transmission and distribution improvements, which many parties supported, the Decision says only that this is a complex issue and "requires more development" or "additional scrutiny is needed" (p. 34, emphasis added):

> We do not adopt other components of the Renewable FiT Staff Proposal, including the location adder or a transmission adder because we find these components either inconsistent with existing law or <u>require more development</u>. Regarding the transmission adder, we find that the record does not support a determination that the transmission costs for particular RAM contracts constitute the avoided transmission costs for renewable FiT generators under the law. As discussed previously regarding Clean Coalition's suggested location adder, we agree with the concerns expressed by SCE and the other utilities that <u>additional scrutiny is needed</u> before the Commission adopts a location adder.

The Decision also fails to include "avoided transmission and distribution improvements" in its list of price requirements on page 16, apparently ignoring the law as chaptered.

Locational benefits are real ratepayer benefits. Many parties have commented on these issues during this proceeding. Figure 1 shows the ratepayer benefits from avoided Transmission Access Charges (TACs) and Figure 2 shows the superior value of Wholesale DG.

Figure 1 shows that wholesale DG projects avoid substantial ratepayer costs in terms of avoided TACs, amounting to as much as 2.5 c/kWh. This is the case because increased Wholesale DG can lead to avoided transmission line construction, which is the basis of TACs. So as more WDG comes online, fewer transmission projects or upgrades are needed and ratepayers save directly. This is, however, just one component of the locational benefits WDG projects enjoy.

Figure 2 shows that Wholesale DG is cost-competitive with central station facilities, with remote solar projects requiring new transmission costing on a net basis $53/MWh and $57 for 1-5 MW "neighborhood" projects located close to load. (It's important to point out that the E3 analysis uses outdated cost figures for solar, so these net cost calculations are too high for a substantial margin).

Figure 1. *Ratepayer benefits from avoided TACs (source: Clean Coalition).*

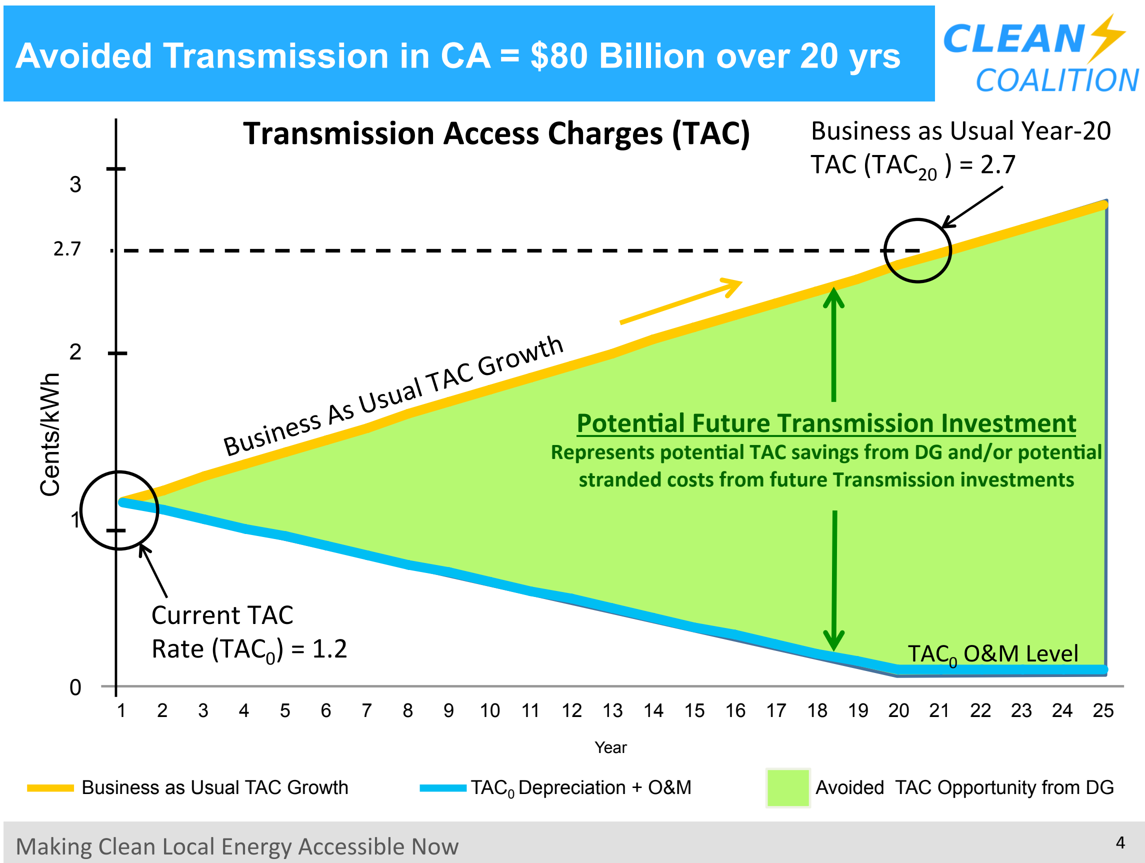

Figure 2. *Value of Wholesale DG is comparable to central station (source: E3).*

Example Values by Interconnection Point

+ Values using CPUC "net cost" approach ($/MWh)

DG Benefit	Interconnection Point: Home (5 kW)	Neighbor-hood (1-5 MW)	Community (5-20 MW)	Remote, existing Tx (150 MW)	Remote, new Tx (150 MW)
Levelized Cost	**$231**	**$167**	**$154**	**$121**	**$105**
Locational energy value	-$39	-$39	-$39	-$34	-$34
Reduced Losses	-$3	-$3	-$1	-	-
Capacity Value	-$35	-$35	-$35	-$38	-$38
Reduced need for distribution	-$26	-$26	-	-	-
Reduced need for transmission	-$7	-$7	-$7	-	+$20
Net Ratepayer Cost	***$121***	***$57***	***$72***	***$49***	***$53***
Environmental/ other benefits	**?**	**?**	**?**	**?**	**?**

Energy+Environmental Economics

Values based largely on CPUC RPS Calculator

12

In sum, exclusion of a locational adder is a violation of law because SB 32 requires compensation for the value of avoided transmission and distribution costs. This is not a small issue, as the Commission's own staff proposal and report commissioned from E3 demonstrated: the value to ratepayers from these avoided costs can be as high as 7-8 c/kWh in some areas.

SB 32 requires that ratepayers be indifferent to the costs of the SB 32 program (P. U. Code section 399.20(d)(4)).[6] This means not only that ratepayers are not to pay more for these projects than the avoided cost, but also that ratepayers can't

[6] Section 399.20(d)(4) states:

> The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.

receive uncompensated benefits/value from SB 32 projects. By denying program participants payment for avoided transmission and distribution costs, ratepayers will receive uncompensated value.

At the very least, the Commission must state clearly a schedule for completing these analyses and modifying the SB 32 program accordingly, rather than deferring them to an uncertain future date, as is the case in the Decision.

5. The Decision fails to provide compensation for mitigation of local environmental compliance costs, as required by Section 399.20(d)(1).

California Public Utilities Code section 399.20(d)(1), enacted by SB 32, states (emphasis added):

> The payment shall be the market price determined by the commission pursuant to Section 399.15 and shall include all current <u>and anticipated environmental compliance costs</u>, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.

The Decision <u>acknowledges</u> that it has failed to implement this portion of the law (p. 38):

> We seek to pay generators the price needed to build and operate a renewable generation facility. We do not find, however, that specific costs, such as compliance costs in a particular air quality management district, are necessarily captured by the RAM methodology [which the FD uses to set the starting price for SB 32]. More analysis is needed.

However, the statute directs the Commission to follow a specific price formula that better balances the desire for ratepayers to pay lower prices <u>and</u> for developers to be incentivized appropriately, including the ratepayer indifference language already cited. Further, SB 32 makes no allowance for the Commission to pick and choose which portions of SB 32 it will implement and when. The Commission must implement SB 32 in total, including providing compensation for "mitigation of emissions and greenhouses and air pollution offsets…"

At the very least, the Commission must state clearly a schedule for completing these analyses and modifying the SB 32 program accordingly, rather than deferring them to an uncertain future date, as is the case in the Decision. The fact that the Commission has taken three years since SB 32 was enacted to reach this point does not inspire confidence that these required additions will happen in a timely manner unless a deadline is set. Most, if not all, of these environmental compliance cost data are already publicly available.

6. The "strategically located" test should be a bright line test

The Decision changed the PD's "strategically located" requirement such that a project must interconnect to the distribution grid and not incur transmission upgrade expenses over $300,000 (FD, p. 52). However, in certain circumstances this expense allowance will be exceeded simply through the IOU requirement to add Direct Transfer Trips (DTTs) to the transmission line, even for distribution-interconnected projects. DTTs costs are estimated at $250,000 each, but this may well go up or down significantly, leading to the possibility that even one DTT will exceed the $300,000 allowance and two will obviously exceed the $300,000 allowance. It seems that this requirement may eliminate a substantial portion of potential SB 32 projects if allowed to remain as is.

Moreover, interconnection procedures are currently broken in California[7] and the utilities acknowledge that their cost estimates are unreliable by as much as a

[7] The Commission recently approved the Phase 1 Rule 21 settlement in its September meeting. The new Rule 21 includes some significant improvements, but the Clean Coalition is not optimistic that we will see much of a net improvement in interconnection procedures until Phase 2 is completed in 2013.

factor of ten (an "order of magnitude").[8] Thus, any screen based on a cost estimate is by definition unreliable by as much as a factor of ten. Accordingly, the $300,000 limit on network upgrades as a criterion for assessing "strategically located" is fundamentally non-compliant with the law in that there is no assurance that such a location is strategically located. If nothing else, this criterion is ripe for abuse, as it allows the IOU to practice market discrimination with their non-transparent study methodology, with little recourse for the developer to challenge what remains a "black box" of "engineering judgment" in many regards. Rather than allowing IOUs to use their opaque interconnection procedures and "engineering judgment" to disallow Re-MAT projects, as will be the case under the Decision's current criterion for "strategically located," the Commission should modify the Decision to require a bright line test that is predictable and not susceptible to abuse.

<u>We previously recommended, instead of the $300,000 limitation, that projects be considered "strategically located" if the power produced comprises less than or equal to the minimum coincident load on the substation at issue</u>, in the aggregate with any other projects proposed (Clean Coalition Opening Comments on Proposed Decision, p. 19). We reiterate that recommendation here. The Staff Proposal recommended the same method for defining "strategically located" (p. 23):

> In order to implement this statutory language, staff defines "strategically located" as projects that serve load in order to avoid adverse impacts to the distribution and transmission system. Thus, a project should not exceed the minimum load at the substation. This type of requirement predetermines that the grid is adequate and that the generation will not adversely impact utility operation. In addition, as parties state in the

[8] For example, SCE's CREST program Facility Studies or joint SIS/FS (under Rule 21) state that the cost estimates provided (keep in mind that a Facilities Study cost estimate is supposed to be far more firm than a System Impact Study estimate) are "non-binding order of magnitude cost estimates." This should make it clear how unwise the Decision's reliance on a firm $300,000 figure is, given this enormous uncertainty from the utilities.

record, the purpose of the interconnection study is to determine the upgrades needed to ensure the generator will not adversely impact utility operation and load restoration efforts. Thus, if this requirement or a similar requirement is implemented, the IOUs cannot deny tariffs based on 399.20 (n)(2) and (n)(4).

7. Guaranteed Commercial Operation Date should be changed to 18 months plus unlimited extensions for delays beyond the developer's control

The Decision sets a Commercial Operation deadline of 24 months plus up to six months for delays outside of the control of the developer. This is contrary to the intent of SB 32 to bring projects online expeditiously. The deadline should instead be 18 months from the date of signing the Interconnection Agreement by the applicant and the utility, or the date of signing the PPA, whichever is later, plus unlimited extensions for delays beyond the developer's control. The most substantial delays are interconnection delays caused by the utility, and the developer should not be put at risk for deadlines that they have no control over.

The Commission has been trending in recent decisions towards allowing longer COD timelines and that trend should be reversed. Shorter timelines were put in place in other programs specifically as a viability screen as well as to discourage price speculation. These features should be encouraged to make sure developers are being held responsible – but also to provide developers extensions for issues outside of their control.

8. The Decision erroneously suggests that developers can use the IOU interconnection maps to determine whether a project is likely to have transmission impacts.

The Decision erroneously suggests that developers can use the IOU interconnection maps to determine whether a project is likely to have transmission impacts. The Decision states (p. 53): "We expect generators to use the utilities' Interconnection Maps, available to the public and online, to locate sites that have a low likelihood of transmission impacts. "

As the Clean Coalition wrote in opening comments on the PD, however, this is not possible (Clean Coalition Opening Comments on PD, p. 20). The IOU maps have no data that will help developers determine potential transmission impacts, in terms of how the IOUs determine transmission impacts. This issue is a substantial obstacle to SCE's CREST queue at this time, because all or almost all (it's not entirely clear due to the CREST program's opaqueness) CREST projects are facing transmission impacts even though they are by definition 1.5 MW or smaller. Many CREST projects have had to endure very long waiting periods while SCE studies their interconnection costs, only to find out that SCE simply can't provide a firm estimate of the costs or the time period required to interconnect because of vaguely defined transmission impacts (this issue is known among developers as the "transmission vague" problem). This problem is highlighted by the fact that after four years of the CREST program being available, literally only 5.25 MW of new projects are now online (all solar projects), from an available program capacity of over 200 MW.[9] The Decision's directions on interpreting "strategically located" do not resolve this problem or allow SB 32 developers to judge the likelihood of transmission impacts from their new projects.

9. A set-aside for projects 1 MW and below should be added

Note: this recommendation is not joined by Clean Coalition.

CALSEIA urges the Commission to include a set-aside within the feed-in tariff program for smaller renewable projects, specifically those projects sized 1 MW and below. Without a set-aside it is highly likely that few, if any, small projects will be able to participate. While we understand that staff believes the

[9] http://asset.sce.com/Documents/Shared/120611_ExecutedCRESTPPAs.xls

“strategically located” requirements will allow small projects to flourish, that strategy is unproven. Further, it is well-recognized that smaller projects are likely to need a higher PPA price to be able to participate. Coupled together, these two factors mean that smaller projects – while they may be able to pass muster regarding interconnection logistics – will have to wait for higher prices to be able enter the program, which are very unlikely to occur given the high demand for PPAs and consequent price drops.

Further, California has provided unprecedented support to the solar industry – in part to ensure growth in the market place while ensuring a move towards cost competitive renewable technologies. The feed-in tariff is essentially the bridge from the California Solar Initiative to the future for small-scale solar. The expectation that multiple 500 kW or smaller projects will be able to successfully compete with a single 3 MW project is not economically realistic given the economies of scale. The Commission should ensure a viable market for sub-MW projects going forward, since failure to do so would constitute a waste of the small-scale infrastructure investment already made by the state and would be a lost opportunity to smoothly transition from CSI to a longer-term procurement mechanism for this key market segment.

10. Smaller suggested “fixes”

There are also a number of smaller changes that should be made to the Decision.

- Fix usage of terms like sponsor, developer, seller, generator
    - Example: Section 6.4 switches from generator to developer in middle of section and then switches to sponsor in 6.4.1
- Clarify developer experience criterion for price adjustments when multiple entities are involved in a single project. In other words, if

multiple entities are involved, is one person enough to satisfy the developer experience criterion?

- Clarify the "initial starting capacity" provision in section 6.4.1. The Decision should be revised to clarify that the "initial starting capacity" is both the capacity for the first period, as well as subsequent periods.
- The IOU proposed tariffs showed different treatment with respect to executing the last contract in each bucket, when the remaining allocation is less than 3 MW. The Commission should direct that the project that fills the bucket can be larger than the remaining bucket capacity – up to the 3 MW limit, as PG&E's proposed tariff allows. The IOU suggestion that the last project not receive a contract if it's technically too big is contrary to the first come first served requirement in SB 32.
- Sections 6.4 and 6.7 have many typos
- "Bid fee" should be replaced with "Application fee" because there are no bids in this feed-in tariff program. The Decision should also specify when the fee is due and whether or not it is refundable.

II. Conclusion

For the many reasons described above, the Commission should substantially modify D.12-05-035 to create a viable and sustainable feed-in tariff program, as required by SB 32 and various policy goals like the Governor's 12,000 MW DG by 2020 goal.

Respectfully submitted,

TAM HUNT

Attorney for:
Clean Coalition

2 Palo Alto Square
3000 El Camino Real, Suite 500
Palo Alto, CA 94306
(805) 214-6150

Dated: November 12, 2012

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 12th day of November, 2012, at Santa Barbara, California.

Tam Hunt

Clean Coalition