BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

| Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program. | Rulemaking 11-05-005 (Filed May 5, 2011) |
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**COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON PROPOSED DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X AND DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES**

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The Interstate Renewable Energy Council, Inc. (IREC)[1] submits these comments pursuant to Rule 14 of the California Public Utilities Commission (CPUC or Commission) Rules of Practice and Procedure. IREC generally supports Administrative Law Judge DeAngelis's Proposed Decision (PD), distributed March 20, 2012. The PD complies with the statutory mandate for Feed-in Tariff (FiT) projects to count towards the investor-owned utilities' (IOUs') Resource Adequacy (RA) procurement requirements while abiding by SB 2 1X's ratepayer indifference requirement.[2] The PD's interpretation of the language "strategically located" is faithful to both state policy and the statute's intent to restrict eligibility to projects located near load.

1 IREC is a U.S. Internal Revenue Code § 501(c)(3) non-profit organization that has worked for nearly three decades to expand retail electric customer access to renewable distributed generation resources. IREC achieves this goal through the development of programs and policies that reduce barriers to renewable energy deployment and increase consumer access to renewable technologies. IREC focuses on policies that directly impact customer access to renewable technologies, including net metering rules, community renewable power programs and interconnection procedures.

2 Cal PU Code §§ 399.20(d)(4) and 399.20(i).

While the PD makes appropriate and reasonable strides to implement California's FiT, some clarifications and revisions to the PD are required to more accurately enact its policy. The phrase "utilization of the transmission system and new transmission infrastructure or transmission system network upgrades" creates uncertainty regarding project eligibility.[3] Further, the PD inhibits investor certainty because a project's use of the transmission system, or the need to construct transmission upgrades, may not be known until after its commercial operation date (COD), creating open-ended risk for FiT eligibility. Finally, it appears that the allocation of 750 MW will not be achieved by the proposed methodology due to exemptions for smaller publicly owned utilities in SB 32 and exemptions for smaller IOUs in the PD.

The PD should be revised to:

- Consider all projects proceeding through Fast Track to meet the "strategically located" goals of the FiT.
- Remove the restriction on "utilization of the transmission system" as the term is vague and does not necessarily reflect whether a project is "strategically located."
- Include the interconnection screen for transmission interdependency for non-Fast Track projects in order to clearly and predictably determine whether a project is "strategically located" instead of relying on whether the project necessitates "new transmission infrastructure or transmission system network upgrades."
- Ensure that eligibility for the FiT program is permanent and established at the time of contract execution.
- Include an allocation methodology that will fully allocate the 750 MW envisioned for the program.

These clarifications will increase the transparency of the FiT program's requirements and ensure sufficient projects will be available to achieve state goals.

[3] Proposed Decision in R.11-05-005 at 63 (March 20, 2012) (PD).

## I. THE PD BALANCES THE REQUIREMENT TO PROVIDE RESOURCE ADEQUACY CAPACITY WITH THE NEED TO MAINTAIN RATEPAYER INDIFFERENCE.

### A. Achieving Full Capacity Deliverability Status is a Heavy Burden for Small Projects.

A generator must apply for a deliverability assessment and obtain Full Capacity Deliverability Status (FCDS) through the interconnection process in order to count towards a utility's RA requirements. The PD correctly recognizes the twin burdens of achieving FCDS for small generators: high costs and lengthy timelines.[4] IREC stressed these burdens in its revisions to, and comments on, the utilities' FiT Proposed Standard Form Contract.[5] Requiring a project to apply for a deliverability assessment and achieve FCDS increases costs for developers and slows project development without providing evidence of corresponding value to ratepayers.

The problem originates in the California Independent System Operator's (CAISO's) deliverability assessment, which is currently the only pathway to FCDS available in the state.[6] In its current form, the assessment is expensive, time consuming and ill-suited to considering the RA value of distributed generation. As the PD states, "CAISO only performs deliverability studies once a year," the "total study process can take two years," and it "may require costly upgrades to the transmission system in order to make the generator fully deliverable."[7] Further, the deliverability assessment is only available in a limited manner for Fast Track and

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4 PD at 51.

5 The document *IREC Redline and Explanatory Comments on FiT Contracts* was served on parties to R.11-05-005 on March 5, 2012, but were not filed with the Commission. The comments can be made available upon request.

6 The ISO conducts the Deliverability Assessment option in the utilities' Federal Energy Regulatory Commission (FERC)-jurisdictional interconnection tariffs.

7 PD at 51.

Independent Study Process applicants in the utilities' wholesale interconnection tariffs (WDATs), thereby greatly extending the time projects would have to wait to come online.[8]

CAISO is currently revising its deliverability assessment for distributed generation resources.[9] However, those changes will not apply until the 2013-14 RA year, and the success of the revisions will not be known until much later.[10] Until those changes have been implemented, a requirement to apply for and achieve FCDS will needlessly increase costs and delay CODs for the small projects that the FiT Program targets.

### B. The PD Addresses Both the Cost and the Timeline Issues in a Manner that Ensures Ratepayer Value and Project Viability.

The PD avoids the increased costs and delays that accompany FCDS by creating a bifurcated pricing mechanism and allowing projects to achieve deliverability after the COD. The PD's pricing framework allows projects to pursue a higher time-of-delivery (TOD) factor if it is economical for the project to achieve FCDS. Projects that require upgrades to achieve FCDS will be able to offset the cost of deliverability with a higher contract price, meaning the FiT program will be economically feasible for more projects.[11]

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8 The utilities use different names for their FERC-jurisdictional interconnection tariffs. SCE and SDG&E each use "Wholesale Distribution Access Tariff" (WDAT), while PG&E uses "Wholesale Distribution Tariff." These Comments use the term "WDAT" to refer to each utility's tariff.

9 California Independent System Operator, *Resource Adequacy Deliverability for Distributed Generation Draft Final Proposal* (March 29, 2012) (available at: http://www.caiso.com/Documents/DraftFinalProposal-Deliverability-DistributedGeneration.pdf).

10 *Id.* at 9.

11 IREC notes that the Commission may want to clarify whether a project that requires deliverability upgrades to the transmission system would still be considered "strategically located" pursuant to the requirements set out in the PD at 63. This requirement is discussed further below.

Further, "generators can convert to full deliverability after their online date."[12] This important provision will allow projects to interconnect without the multi-year delays of the CAISO deliverability assessment, meaning more projects will come online quickly. In addition, the utilities' WDATs allow for a deliverability assessment to be conducted after the COD.[13] Thus, if the provision of RA becomes economical for a project, it will be able to take advantage of the higher price at any time. These two aspects of the PD relieve both the cost and timeline burdens that would have otherwise plagued small projects if the PD had required FCDS before the COD. Instead, the PD balances the utilities' need to count projects towards RA procurement requirements and the needs of developers for efficient, cost-effective interconnection.

### C. The PD is Faithful to the Statutory Requirement of Providing RA Capacity in a Manner that Maintains Ratepayer Indifference.

Sections 399.20(d)(4) and 399.20(i) create two potentially competing interests in the FiT program. The latter requires capacity from FiT generators to "count toward the electrical corporation's resource adequacy requirement for purposes of Section 380."[14] The former 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.[15]

Read together, the FiT statute requires projects to count towards the IOUs' RA procurement mandates in a manner that maintains ratepayer indifference to whether the RA is procured through the FiT program or through other, more cost-effective procurement mechanisms. The PD's bifurcated TOD rates accomplish this end by allowing projects to count towards RA requirements up until the point where investments to do so would violate ratepayer indifference.

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12 PD at 51.

13 *See, e.g.,* Southern California Edison Wholesale Distribution Access Tariff, Attachment I §§ 4.7.1 and 4.7.2 (SCE WDAT).

14 Cal PU Code § 399.20(i).

15 *Id.* at § 399.20(d)(4).

A requirement that all projects achieve FCDS would likely cause ratepayers to pay for RA capacity at above-market rates. The Commission has recently estimated that the value of RA capacity is low. The proposed decision in R.11-09-014 states that the short-run value of RA capacity is $28 per kW-year, reflecting "the large surplus of capacity currently available." [16] The PD here recognizes that a deliverability "study may require costly upgrades to the transmission system in order to make the generator fully deliverable."[17] Generators absorb the cost of upgrades to the project's interconnection facilities and the distribution system, but ratepayers refund projects for any network upgrades to achieve deliverability.[18] Where the cost of ratepayer funded deliverability upgrades is greater than the value of the RA provided, ratepayer indifference is violated.

The PD uses the market to avoid this end. It ensures the utilities will receive RA credit for FiT projects with FCDS, and it guarantees ratepayers will remain indifferent to energy-only projects where the cost of achieving FCDS outweighs the RA value provided. Under the PD, the IOUs will set TOD factors for both FCDS and energy only projects. The delta between the FCDS TOD rate and the energy only TOD rate should reflect the value of RA capacity. Projects located in areas where the delta is greater than or equal to the costs to achieve deliverability will interconnect as FCDS, and projects located in areas where the delta is less than the costs to achieve deliverability will interconnect as energy only. Thus, FiT projects will count towards RA requirements up until the point where investments to do so would violate ratepayer indifference. In this way, the PD balances the competing provisions of providing RA capacity and maintaining ratepayer indifference.

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16 Proposed Decision in R.09-11-014 at 34 (March 20, 2012).

17 PD at 51.

18 California Independent System Operator Tariff, Appendix Y § 12.3.2. The CAISO Tariff, Appendix A, notes that Network Upgrades "shall consist of Delivery Network Upgrades and Reliability Network Upgrades."

## II. THE PD'S INTERPRETATION OF "STRATEGICALLY LOCATED" SHOULD BE REVISED TO PROVIDE CLARITY AND ENSURE INVESTOR CERTAINTY.

SB 2 1X requires FiT projects to be "strategically located" and interconnected so as to "optimize the deliverability of electricity generated at the facility to load centers." [19] The PD interprets the language "strategically located" to mean that a project must be "interconnected to the distribution system" and "sited near load." [20] Such an interpretation squarely applies the statutory language, optimizes deliverability of FiT electricity, maximizes the benefits from distributed generation, and provides proper siting incentives for project developers. However, the manner in which the PD implements its "sited near load" criterion creates two issues:

1. The phrase "utilization of the transmission system and new transmission infrastructure or transmission system network upgrades" creates uncertainty as to when a project will be disqualified from FiT eligibility, and the terms are not clearly defined. [21]

2. When combined with provisions in the utilities' interconnection tariffs, the PD creates open-ended risk for project developers because a project's use of the transmission system, or the need to construct transmission upgrades, may not be known until after significant investments have been made in a project.

Granting eligibility to all projects that can either interconnect using the Fast Track process or pass the utilities' interconnection screen for transmission interdependency will resolve both issues by clearly establishing, in an administratively easy manner, when a project will be considered "strategically located".

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19 Cal PU Code § 399.20(b)(3).
20 PD at 63.
21 *Id.*



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### A. The PD Should Employ the Utilities' Transmission Interdependency Screen to Ensure FiT Projects are "Located Near Load."

The PD lacks a clear and robust definition of whether a project is "sited near load" and "optimizes the deliverability of electricity generated at the facility." [22] The PD states that projects that require both "utilization of the transmission system" *and* "new transmission infrastructure or transmission system network upgrades" will be ineligible for the FiT.[23] The PD does not define what constitutes "utilization of the transmission system" or "new transmission infrastructure."[24] IREC understands the term "transmission system network upgrades" as it is defined in the utilities' interconnection tariffs, but it is unclear if the PD employs that definition.[25] IREC is unaware of a definition for what constitutes utilization of the transmission system and is concerned that the IOUs may argue that all projects utilize the transmission system in some manner.

IREC would like to propose an alternate approach that achieves the same goals but in a clearer manner. First, all projects that can be interconnected using Fast Track under either Rule 21 or the WDATs should be considered to be strategically located. The Fast Track screens ensure that a project is located close to load and generally will result in no upgrades to the transmission system. For projects that do not qualify for Fast Track, applying the transmission interdependency screen from the recently filed Rule 21 Settlement Agreement, or those found in the WDATs, as an eligibility criterion can help identify whether a project utilizes the transmission system. It asks if a proposed project is electrically interdependent with the CAISO

22 *Id.* at 63; Cal PU Code § 399.20(b)(3).
23 PD at 63.
24 *Id.*
25 *Id.*

transmission system and, therefore, must be studied with other interconnection requests with transmission system interdependencies.[26] The Proposed Rule 21 screen states:

> **Screen Q: Is the Interconnection Request electrically Independent of the Transmission System?**
>
> Distribution Provider, in consultation with the CAISO, will determine, based on knowledge of the interdependencies with earlier-queued interconnection requests under any tariff, whether the Interconnection Request to the Distribution System is of sufficient MW size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Network Upgrades. If Distribution Provider determines that no interdependencies exist as described above, then the Interconnection Request will be deemed to have passed Distribution Provider's Determination of Electrical Independence for the CAISO Controlled Grid. If Distribution Provider determines that interdependencies exist as described above, then Applicant may be studied under the Transmission Cluster Study Process as set forth in Section F.3.c.
>
> Distribution Provider will coordinate with the CAISO if necessary [to] conduct the Determination of Electrical Independence for the CAISO Controlled Grid as set forth in Section 4.2 of Appendix Y to the CAISO Tariff. The results of the incremental power flow, aggregate power flow, and short-circuit current contribution tests set out in Section 4.2 of Appendix Y to the CAISO Tariff will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.[27]

Application of this screen as a FiT eligibility criterion provides an adequate measure of whether a project impacts the transmission system and, therefore, optimizes the deliverability of its electricity. It is possible some projects that pass this screen may still trigger transmission system

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26 Revised Rule 21 § G.3.a, attached as Attachment A to the Settlement Agreement attached to the *Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, R. 11-09-011 (March 16, 2012) (Revised Rule 21). IREC recognizes that the Commission has not yet approved the modifications to Rule 21, however it seems appropriate to refer to these provisions at this time as the current Rule 21 would create a number of additional complications for the FiT program. Until approval of the Revised Rule 21, the utilities can apply the transmission interdependency screen independent of the interconnection process.

27 Revised Rule 21 § G.3.a; *see also* SCE WDAT, Attachment I § 5.5.1; Pacific Gas and Electric Company Wholesale Distribution Tariff, Attachment I § 3.1.1.1.



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upgrades, but this possibility must be balanced with the need for a clear requirement that can be easily administered.

The transmission dependency screen can be applied as a matter of course during interconnection, making it easy to administer without increasing the time required for projects to come online. FiT projects that interconnect through Rule 21 or the WDAT have the option of being evaluated under either Fast Track or the Independent Study Process. If a project has passed the Fast Track or Supplemental Review screens, it has automatically passed the interdependency screen because those processes include minimum load screens, which ensure an interconnection will not impact the transmission system.[28] Projects that fail the Fast Track screens, or are not eligible for review under Fast Track, can be reviewed under the Independent Study Process, where the transmission interdependency screen will be applied.

Moreover, the interdependency screen complies with the six project viability criteria that the PD adopts in Section 11. The "Interconnection" criterion states that a project must complete a "System Impact Study, Phase I study, or [have] passed the Fast Track screens or supplemental review" to be considered viable.[29] Using the interdependency screen as an eligibility criterion will ensure that projects have complied with this provision. In fact, the Commission could remove the language "Phase I study" from the interconnection criterion since a Phase I study only occurs in the WDAT cluster process, and projects only need to enter the WDAT cluster process if they fail the interdependency screen.

Incorporating an interdependency screen into the determination of whether a project is "sited near load" will provide a robust, clear and administratively easy definition of project

28 *See, e.g.,* SCE WDAT, Attachment I § 6.5.2; Revised Rule 21 §§ G.1a-G.2.c.
29 PD at 64.



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eligibility. The PD should be revised to require the utilities to draft a provision incorporating the screen.

### B. Eligibility for the FiT Program Should be Permanent and Established at the Time of Contract Execution.

The utilities' interconnection tariffs require a Fast Track customer to retain all responsibility for the costs associated with its facility, including costs that may arise after an interconnection agreement has been signed.[30] These broad provisions can be read to extend to transmission system network upgrades that are required after a project's COD and result from later cluster studies or changed circumstances in load or generation near the project's point of interconnection. Under the PD, eligibility for the FiT Program hinges on impacts to the transmission system. Combined with the interconnection provisions, the PD creates open-ended risk for project developers because use of the transmission system, or the need to construct transmission infrastructure or upgrades, may not be known until after an interconnection agreement has been signed, and a developer has begun constructing its facility.

Investor certainty requires that eligibility for a FiT contract is constant and established at the time of contract execution. The PD should be revised to ensure that qualification for FiT contracts will be established at the time a project signs a FiT agreement and cannot change based on later transmission use or upgrade determinations.

## III. THE PD'S ALLOCATION METHODOLOGY SHOULD BE ADJUSTED SO THAT THE ALL OF THE PROGRAM'S 750 MW ARE ALLOCATED.

It appears that the PD's allocation methodology described on page 72 will result in only 652 MW of FiT obligations being allocated, rather than a full allocation of 750 MW. The PD

30 *See, e.g.,* SCE WDAT § 6.11.5; Revised Rule 21 § E.4. It is not clear from the WDAT tariffs whether the utility may impose costs after an interconnection agreement is signed for Independent Study Process projects, however, the provision in the Revised Rule 21 does apply to Independent Study Process projects as well.



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bases allocation on each utility's percentage contribution to statewide peak demand, but that will not add up to 100% because smaller utilities are exempt. IREC suggests that the PD's methodology be revised to allocate FiT obligations based on each utility's share of coincident peak demand of the utilities subject to the FiT.

Senate Bill 32 establishes a 750 MW statewide FiT program and creates section 387.6(e), which provides that publicly owned utilities (POUs) serving over 75,000 retail customers must have a FiT program "based on" their proportionate share of statewide peak demand. This provision exempts most POUs, and presumably none of the exempt POUs will voluntarily participate. Based on 2010 customer data from the Energy Information Administration (EIA), the only POUs with retail customer counts in excess of 75,000 are the eight listed in the table below.[31]

In addition to the exemption for smaller POUs, smaller IOUs will be exempt from establishing FiT programs pursuant to the PD.[32] The PD exempts all but the three largest IOUs, and the three smaller IOUs have customer counts well under 75,000, which thereby aligns the customer count requirements for IOUs and POUs.

The following table provides EIA customer counts, coincident peak demands,[33] allocations based on a straight percentage of statewide peak demand, and allocations based on a percentage of aggregate peak demand of the non-exempt utilities. As shown in the table, the non-exempt utilities account for 86.9% of statewide peak demand, and basing FiT allocations on

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31 United States Energy Information Administration website, *Class of Ownership, Number of Consumers, Sales, Revenue, and Average Retail Price by State and Utility: All Sectors, 2010 (Table 10),* available at http://www.eia.gov/electricity/sales_revenue_price/xls/table10.xls.

32 PD at 67 (explaining that the Commission has authority to adjust FiT requirements for IOUs with fewer than 100,000 customers, as provided in SB 32's addition of §399.20(c)).

33 2010 coincident peak demands are listed in filings provided individually by the utilities and available at http://energyalmanac.ca.gov/electricity/s-1_supply_forms_2011/, as provided in the PD at footnote 62 on p. 72.

an unadjusted share of statewide peak demand would only allocate 651.77 MW. Basing allocations on the 52,834 MW of coincident peak demand for the non-exempt utilities is an effective way to assure that all 750 MW of FiT program capacity is allocated.

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| **Utility Name**[34] | **Utility Type** | **2010 EIA customer count** | **2010 Coincident Peak** | **% of Statewide Peak** | **Unadjusted Share (MW)** | **% of non-exempt peak** | **Adjusted Share (MW)** |
|---|---|---|---|---|---|---|---|
| PG&E | IOU | 5,212,602 | 17,742 | 29.18% | 218.87 | 33.58% | 251.85 |
| SCE | IOU | 4,880,765 | 18,342 | 30.17% | 226.27 | 34.72% | 260.37 |
| LADWP | POU | 1,450,410 | 6,177 | 10.16% | 76.20 | 11.69% | 87.69 |
| SDG&E | IOU | 1,378,468 | 3,953 | 6.50% | 48.76 | 7.48% | 56.11 |
| SMUD | POU | 596,014 | 2,962 | 4.87% | 36.54 | 5.61% | 42.05 |
| Anaheim | POU | 146,646 | 545 | 0.90% | 6.72 | 1.03% | 7.74 |
| Imperial ID | POU | 114,069 | 1004 | 1.65% | 12.39 | 1.90% | 14.25 |
| Modesto ID | POU | 112,644 | 611 | 1.00% | 7.54 | 1.16% | 8.67 |
| Riverside | POU | 106,062 | 594 | 0.98% | 7.33 | 1.12% | 8.43 |
| Turlock ID | POU | 99,608 | 569 | 0.94% | 7.02 | 1.08% | 8.08 |
| Glendale | POU | 84,678 | 335 | 0.55% | 4.13 | 0.63% | 4.76 |
| | | | | | | | |
| Totals | | | 52,834 | 86.90% | 651.77 | 100% | 750.00 |

The Commission cannot dictate how the POUs will determine their allocations, but the Commission can establish a logical way to determine the IOUs' allocations and provide an example for the POUs to follow.[35] Adjusting the IOUs allocations as suggested here will add

[34] Abbreviations used in table: Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Power District (SMUD), City of Anaheim (Anaheim), Imperial Irrigation District (Imperial ID), Modesto Irrigation District (Modesto), City of Riverside (Riverside), Turlock Irrigation District (Turlock ID), City of Glendale (Glendale).

[35] PD at 87.

74.44 MW to their allocations, and the eight non-exempt POUs will then be likely to add 23.79 MW to their allocations.

The PD relies on the allocation methodology developed in D.07-07-027,[36] but that decision allocated a 250 MW program over California's six IOUs without exemption. The publicly-owned utilities were not previously required to participate, so there was no issue regarding exempt POUs. With the exemptions provided in SB 32 for smaller POUs and in the PD for smaller IOUs, a different allocation methodology is needed, as suggested here.

## IV. CONCLUSION

The Commission should revise the PD per IREC's recommendations above in order to increase the transparency of the FiT program's requirements and ensure sufficient projects will be available to achieve state goals.

Respectfully submitted,

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April 9, 2012

36 *Id.* at 68.

## APPENDIX – PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

### FINDINGS OF FACT

31. ~~Consistency and administrative simplicity will be furthered by retaining the existing allocation methodology for 750 MW, updated in certain respects, adopted by the Commission in D.07-07-027.~~ Publicly-owned utilities with fewer than 75,000 customers are exempt from the statewide FiT program, and therefore program allocations based on each non-exempt utility's percentage of statewide peak demand will not fully allocate 750 MW. The existing methodology adopted by the Commission in D.07-07-027 only applied to IOUs and there were no exempt IOUs, making that methodology inadequate for allocations in a program with exempt utilities.

### CONCLUSIONS OF LAW

35. The statutory language, "strategically located," is interpreted to optimize the deliverability of electricity generated at the FiT project to load centers, which means that a generator must be interconnected to the distribution system, as opposed to the transmission system, and, in addition, must be sited near load, meaning ~~not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure.~~ the generator passes the utilities' Fast Track or transmission interdependency interconnection screens.

38. The FiT Program cap should be increased to 750 MW and a proportionate share of the 750 MW (with a proportionate share designated for non-exempt publicly owned utilities) should be allocated to the three largest electric utilities regulated by the Commission. The allocations, based on each non-exempt IOU's share of the coincident peak demand of all non-exempt utilities ~~made in accordance with the methodology adopted in D.07-07-027~~, should be as follows: PG&E ~~218.8~~ 251.8 MW; SCE ~~226~~260.4 MW; SDG&E ~~48.8~~ 56.1 MW, for a total of ~~493~~568.3MW.

39. In the interest of consistency and administrative simplicity, it is reasonable to retain the existing allocation methodology, updated in certain respects, adopted by the Commission in D.07-07-027, based on the coincident peak demand of all non-exempt utilities.