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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs	Application 22-05-022
And Related Matters	Application 22-05-023 Application 22-05-024

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION ON THE IMPLEMENTATION OF D. 24-05-065

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ON THE IMPLEMENTATION OF D. 24-05-065

The Solar Energy Industries Association (SEIA) appreciates the opportunity to submit the following comments in response to the *Administrative Law Judge's Ruling Directing Responses to Questions Regarding Implementation of D. 24-05-065* (Ruling), issued on June 5, 2024, as modified by the June 13, 2024 *E-Mail Ruling Granting Request for Extension of Comment Deadlines*.

I. INTRODUCTION

SEIA has reviewed carefully the new community solar program outlined in D. 24-05-065 (Decision) – the Community Renewable Energy Program (CREP). For the reasons that SEIA expressed in the record leading to the Decision, and which we supplement below, we expect that the CREP, if it is workable at all, will make only a minor contribution to California's solar and storage resources. This is due to, first, the requirement that CREP projects use existing wholesale contracts that are not commercially viable for distributed solar resources without changes or adders, and, second, the limited incentive funds available to supplement wholesale contract revenues. The substantial use of limited incentive funds will be necessary to make each CREP project viable, and some of the available incentive funds – such as the federal Solar for

All (SFA) monies – will require the more generous use of incentive funds to provide low-income subscriber credits than anticipated in the Decision. Nonetheless, these comments are offered in a constructive effort to assist the Commission in fashioning a workable new community solar program that we hope can demonstrate, even on a small scale, a path forward for the future, sustained growth of community solar in California.

In this regard, the Commission should bear in mind the legislative intent of AB 2316 – the enabling legislation behind the new CREP:

> It is the intent of the Legislature to create a community renewable energy program *so that all Californians, especially those unable to host a rooftop solar system, realize the benefits of distributed generation t*hrough a cost-effective program that provides benefits to all ratepayers.[1]

This clear intent is mirrored in the statement of Assemblyman Ward when introducing the legislation:

> *Author's Statement.* According to the author, "California has some of the most ambitious renewable energy goals in the world, including 60% renewable energy by 2030 and 100% carbon-free electricity by 2045. *Unfortunately, for a majority of California households, local solar power is not financially and structurally feasible, especially in some of California's most disadvantaged communities.* Assembly Bill 2316, would create a cost-effective community renewable energy program that leverages the ability to combine distributed renewable resources with energy storage to provide all Californians with an option to access the benefits of distributed generation." [2]

The potential for community solar to further a just and equitable energy transition was recognized by Commissioner Houck in her dissent to Decision 24-05-065. Specifically, she noted that community solar...

> …could further reliable, resilient energy systems for all Californians. Community solar programs have the potential to provide benefits for all ratepayers*, and*

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1 AB 2316 (Ward), Section 1 (a) (emphasis added).

2 Assembly Committee on Utilities and Energy, AB 2316 (Ward) – As Amended March 28, 2022 (April 26,2022), p.8 (emphasis added) *available at* https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202120220AB2316#

> *particularly for environmental and social justice (ESJ) and Tribal communities, which advance our ESJ Action Plan 2.0 policy goals*.[3]

Importantly, while Commissioner Houck opined that the CREP adopted by the Commission would not further a just and equitable energy transition, she stated her belief that "there is an opportunity to adjust the program through the next phase of the proceeding" and encouraged "everyone to think outside the box and (particularly the solar industry and the investor-owned utilities) to come to the table with meaningful proposals for implementation that result in cost-effective programs that benefit all interests."[4] The solar industry has done just that. The proposed modifications to the basic framework of the CREP established in the Decision are offered as means to have a program, albeit one considerably smaller than what was envisioned by AB 2316, which will provide for financeable community solar projects and thereby allow for more Californians to equitably participate in the state's energy transition.

II. RESPONSES TO QUESTIONS

A. Revenue Share and Bill Credits

1. **The new community renewable energy program is designed to deliver value through two streams of funding: (i) the stable but moderately adjusting compensation from wholesale tariffs and (ii) the external, non-ratepayer, funding or "adder" that is managed through investor-owned utility (Utility) balancing accounts. How should these streams of funding be applied to provide both developer compensation and subscriber savings or revenue share (i.e., percentage split of total revenue from a project between the developer or generator account and benefiting or subscriber accounts)?**

Response. The Decision requires that the CREP fund new community solar projects through the use of revenues from two sources: (1) the use of the existing wholesale tariffs or power purchase agreements (PPAs) – either the Renewable Market Adjusting Tariff (ReMAT) or

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3 Decision, 24-05-065, Concurrence and Dissent of Commissioner Darcie L. Houck p. 1 (emphasis added).

4 *Id.*, pp. 8-9.

the current Qualifying Facility Standard Offer Contract (QF-SOC) and (2) external, non-ratepayer incentive funds such as the federal SFA money and the $33 million in state funding referenced in the Decision.[5]

Issues. There are a number of issues that must be resolved for this structure to produce viable CREP projects, including:

- **External funding is needed to supplement PPA revenues to support project costs.** Few, if any, solar projects are being developed today under either the ReMAT or the QF-SOC contracts.[6] This is because the revenues available to solar projects under the current pricing in these contracts are inadequate to support new solar projects over their economic lives of 25+ years.[7] There is no chance that these contracts could support more expensive and more valuable solar-plus-storage projects.[8] Thus, the Commission will need to approve additional non-ratepayer funding to developers to allow CREP projects to be sited, permitted, financed, and built. Question 4 of the Ruling recognizes this reality. This also means that external, non-ratepayer incentive funds are likely to be

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[5] See Decision, at p. 118: "… to address the concern that wholesale tariff compensation such as ReMAT and PURPA avoided costs may be insufficient to create and grow interest in community renewable energy program projects, the Commission adopts the use of $33 million appropriated to the Commission for community energy renewable program usage and storage-backed renewable generation programs."

[6] As cited by TURN at pages 3-4 of its opening comments on the proposed decision, [t]he ReMAT program has only resulted in contracts with eight projects (totaling 12.4 MW) since 2017, and none since the program reopened in 2020. The QF-SOC program has only yielded a single new project (20 MW solar) in the last five years. SEIA has verified these numbers by reviewing the Commission's RPS project data base.

[7] The Energy Division's Integrated Resource Planning (IRP) team calculated the 25-year levelized costs of new distributed solar projects, as part of the IRP's *Final 2023 Inputs & Assumptions* document. Their calculated levelized cost for new distributed solar is $78 per MWh in 2025 (in 2022 $). This is $85 per MWh in 2025 $, assuming inflation at 3% per year. See p. 65, Table 41, of the IRP's *Final 2023 Inputs & Assumptions,* available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf. By comparison, the current 20-year ReMAT price for as-available peaking resources is $72 per MWh, per Resolution E-5323.

[8] SEIA also references the costs for solar-only and solar-plus-storage projects presented in the concurrent comments of the Coalition for Community Solar Access (CCSA), which use the Cost of Renewable Energy Spreadsheet Tool (CREST) model that is in the record of this case. CCSA's costs are $108 to $121 per MWh for solar-only projects and $178 to $197 per MWh for solar-plus-storage projects.

needed to provide all credits to subscribers, for both low-income and non-low-income subscribers. One possible circumstance in which project revenues might be adequate to cover project costs and to fund a portion of subscriber credits is if projects qualify for either the 40% or 50% federal Investment Tax Credit (ITC) that is available under the Inflation Reduction Act (IRA) to projects that qualify for the Low-Income Community Bonus Credit. However, the Commission should not assume that projects will be able to access these enhanced ITCs, given that there is a limited amount of such enhanced credits available nationwide, and, as a result, access to the credits is likely to be by lottery.[9]

- **No revenue source for non-low-income subscriber credits.** If CREP projects will require some level of non-ratepayer funding for developers to make up for the shortfalls from the ReMAT or QF-SOC PPAs – as appears likely – then all of the additional funding for subscriber credits also must come from non-ratepayer funds. Yet the Decision states, at page 120, that "non-low-income subscribers… will not receive a subsidy through external funding." Further, SFA funding is limited to supporting benefits for low-income customers and disadvantaged communities.[10] In addition, the Decision states that the $33 million in available state funds also must be allocated to low-income customers.[11] Thus, if the PPAs cannot cover all developer costs, and non-ratepayer external funds can only support low-income subscriber credits, then the

9 For an overview of the Low-Income Communities Bonus Credit Program, see https://www.energy.gov/justice/low-income-communities-bonus-credit-program. The 10% or 20% enhancement in the ITC is available to qualified solar and wind energy facilities with a maximum net output of less than five megawatts (AC) installed in low-income communities or on Indian land (for the 10% enhancement) or that are part of a qualified low-income residential building or a qualified low-income economic benefit project (for the 20% increase). Community solar projects would fall into Category 4 of the types of projects eligible for the bonus ITC.

See also below link to a slide deck assembled by the Department of Energy's Office of Energy, Justice and Equity which provides an overview of the implementation of the program, including how the possible lottery would work: https://www.energy.gov/sites/default/files/2024-05/48e%20Slides%20for%20PY24%20Applicant%20Webinar.pdf

Note that June 27, 2024 was the application deadline to qualify for any lottery needed to allocate bonus ITC credits for 2024. See Slide 17 in the link above.

10 See https://www.epa.gov/greenhouse-gas-reduction-fund/solar-all-fast-facts.

11 Decision, at Finding of Fact 52: "Only low-income households are eligible for the $33 million in funds appropriated to the Commission through AB 102. "

Decision appears to provide no funding source for either (1) the additional project revenues that developers will need to make projects economic or (2) the non-low-income subscriber credits. The Commission should explain from where the funds will be obtained for both of these needs. On this issue, SEIA expects that the Commission may need to modify or clarify the language in the Decision if the CREP is to be a workable program.

- **Inadequate term.** The QF-SOC PPA has a term of just 12 years. This term is too short to allow for reasonable financing of new renewable projects. The maximum 20-year term for ReMAT PPAs is workable. Accordingly, SEIA's proposal in these comments works from the ReMAT PPAs and assumes a 20-year term.
- **Existing ReMAT PPAs are unworkable for solar-plus-storage.** The ReMAT as-available peaking price that would be used for the CREP is based on a sample of solar-only RPS projects with capacities below 20 MW.[12] As a result, the pricing in the ReMAT contract is inadequate to support the higher costs of solar-plus-storage projects that offer more value to the system. The Commission has recognized the importance of encouraging solar-plus-storage projects, because adding significant battery storage greatly increases the value of the solar project output. With storage, the solar energy can be stored and discharged from the battery when the power is most valuable to the

[12] D. 20-10-005, issued October 16, 2020, adopted a methodology for an administrative determination of ReMAT contract prices by ReMAT Product Category. This pricing method is based on the weighted average of IOUs' recent wholesale RPS contracts with RPS facilities with a capacity of 20 MW or less in each Product Category. Historical prices are calculated with a lookback period sufficient to preserve the confidentiality of market-sensitive pricing information of individual contracts. Solar is in the As-Available Peaking ReMAT Product Category. D. 20-10-005 also directed the Energy Division to issue an annual draft Resolution beginning May 2021 to update the administratively set fixed avoided-cost market price for each ReMAT Product Category using the most recently-executed RPS contract price data. The most recently approved ReMAT pricing resolution was Resolution E-5323, adopted by the Commission on June 20, 2024. See https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=534546645.

This resolution shows that the current REMAT As-Available Peaking price of $71.94 per MWh is based on the average price from 27 PPAs of 20 MW or smaller with solar PV projects that were executed between 2020 and 2022. The level of ReMAT As-available Peaking prices in recent years also confirms that the data sample used does not include solar projects with storage capacity.

system.[13] In the Decision, the Commission found that the "voluntary inclusion of storage will likely result in more costly projects, but the cost is balanced with the additional value to the grid that resources combined with storage will provide."[14] In addition, in her public remarks on the Decision, President Reynolds stated her expectation "that all developers will propose storage together with solar systems."[15] The challenge is that adding 4-hour storage with a discharge capacity equal to the solar nameplate essentially doubles the cost of the project, compared to a similar solar-only facility.[16] Pursuant to D. 21-12-032, the ReMAT PPA now allows renewable projects to include storage. However, the PG&E and SDG&E ReMAT PPAs provide no financial benefit from the addition of storage, since the Payment Allocation Factors in these PPAs are 1.0 in every time-of-use (TOU) period. Thus, under these contracts there would be no added revenues from using storage to move power output into the most valuable TOU period. The Payment Allocation Factors in the SCE ReMAT PPA, which are different than 1.0, add only a small amount of revenue for a solar-plus-storage project, and are far too little on their own to support the additional costs of storage.

The QF-SOC does have more significant TOU factors and a small capacity payment focused on the on-peak TOU period, but that contract also is inadequate for solar-plus-storage projects. The small capacity payment is based on short-term resource adequacy (RA) prices, which are intended to support existing generators, not to build new steel-in-the-ground. Moreover, as referenced above, the 12-year term of the QF-SOC is too short for reasonable financing for new generation.

- **Time required to establish full capacity deliverability.** CREP projects – in particular, solar-plus-storage projects – will not be credited for their full reliability and resource adequacy value for ratepayers unless there is a timely and achievable pathway for projects to earn compensation for providing reliability services. Today, small renewable projects are limited to submitting a Wholesale Distribution Access Tariff deliverability

13 D. 22-12-056, pp. 142-143.

14 See Decision, Finding of Fact 66.

15 See https://www.adminmonitor.com/ca/cpuc/voting_meeting/20240530/ at 1:02:31.

16 See the project costs referenced in Footnotes 7 and 8 above.

application that would be studied concurrently with the CAISO cluster study process. These studies can take up 2 to 3 years to complete, and the Cluster 16 window will not open until sometime in 2025, at the earliest. Under this option, a project under development today is looking at 3+ years to receive deliverability. This timeline is not financially sustainable for small projects under 5 MW, and could raise concerns that SFA incentive funds will not be deployed within 5 years, as is required for the U.S. Environmental Protection Agency's (EPA) Solar For All (SFA) funding for community solar.[17]

Proposed Structure. The above issues can be addressed with a structure that begins with the ReMAT PPA with a 20-year term. The IOUs should update the Payment Allocation Factors in their ReMAT contracts to recognize the time-varying value of renewable generation. Because the ReMAT price is based on recent solar-only RPS contracts, it is inadequate to cover the storage costs of solar-plus-storage projects. To address this, solar-plus-storage projects should be eligible for a ratepayer-funded Capacity Adder that is based on the avoided generation capacity costs for the project's storage component. In addition, all CREP projects should receive a Project Adder to cover (1) any remaining developer costs for solar or solar-plus-storage projects plus (2) non-low-income subscriber credits. The Commission could establish this Project Adder administratively, based on a "missing money" revenue requirement calculation. Alternatively, LSEs could conduct reverse auctions to award these adders to projects that require the least amounts of incentive funds. The last necessary element is a Low-income Adder that provides the funds for the bill credits to the low-income subscribers who will constitute at least 51% of project subscribers, as required by AB 2316. The costs for the Project and Low-income Adders would come from external funding.

[17] See the U.S. EPA's *Notice of Funding Opportunity* (NOFO) for the SFA, at page 27.

Finally, CREP projects that are treated as load modifiers in the California Energy Commission's IEPR demand forecast should be recognized as providing resource adequacy benefits to the system. Solar-plus-storage projects that are treated as load modifiers would qualify for the Capacity Adder to the ReMAT contract. This would allow LSEs to realize CREP reliability and resource adequacy benefits in a timely way, avoiding the risks, expense, and multi-year delays associated with the CAISO's interconnection and deliverability processes.

The following **Table 1** summarizes the key elements of SEIA's CREP proposal.

Table 1: *Key Elements of the SEIA CREP Proposal*

Element	How Determined	Source of Funds	Details
ReMAT PPA (As-Available peaking)	Existing wholesale PPA	Ratepayers	Allow projects up to 5 MW. Needs updated Payment Allocation Factors.
Capacity Adder (for solar + storage projects)	Administrative		Avoided generation capacity costs from 2022 ACC
Project Adder	Administrative or Reverse auction	Non-ratepayer incentive funds	Covers: (1) remaining project costs and (2) credits for non-low-income subscribers.
Low-income Adder	Administrative		Covers credits for low-income subscribers. Use SFA formula (20% bill savings) or $0.03/kWh

Here are the details necessary to implement this structure:

- **Updated ReMAT contracts.** The Commission should direct all three IOUs to file updated Payment Allocation Factors for their ReMAT contracts. For PG&E and SDG&E, the Payment Allocation Factors of 1.0 in each TOU period were appropriate for solar-only projects whose as-available output cannot be shifted in time. But these 1.0 factors do nothing to encourage the use of storage to produce power when it is most valuable to the system, in all months of the year. The value of renewable energy is not the same in every hour, and there are reasonable metrics available to reflect this time-varying value. SCE's ReMAT PPA has Payment Allocation Factors that differ from 1.0.

However, these factors appear to be out of date. Accurate and reasonable Payment Allocation Factors in the on-peak periods would help to make solar-plus-storage projects more economic under ReMAT contracts, would encourage this storage to be cycled in all months, and would reduce the need for incentive funds. The utilities have approved TOU factors in their RPS plans that could be used here; another alternative is TOU factors based on the three years of historical CAISO energy price data used for energy pricing in the QF-SOC. The latter option is shown below for the three IOUs, in **Tables 2, 3, and 4**.[18] We propose that the Commission direct all three IOUs to update the Payment Allocation Factors in their ReMAT contracts to use the factors shown in Tables 2, 3, and 4.[19]

Table 2: *Revised PG&E ReMAT Time of Delivery (TOD) Payment Allocation Factors*

Monthly Period	Peak	Mid-Day	Night
Jul – Sep	1.67	0.88	0.92
Oct – Feb	1.51	1.06	1.22
Mar – Jun	1.02	0.41	0.76

TOD Period Definitions:

- Peak = HE (Hours Ending) 18 - 22 PPT all days
- Mid-Day = HE 09 - 17 PPT all days
- Night = HE 23 - 08 PPT all days
- See Appendix C of REMAT PPA, at: https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/ReMAT_PPA.pdf

Table 3: *Revised SCE ReMAT Time of Delivery (TOD) Payment Allocation Factors*

Monthly Period	On Peak	Mid Peak	Off Peak	Super Off Peak
Summer (Jun – Oct)	1.93	1.43	0.89	-
Winter (Nov – May)	N/A	1.30	1.12	0.53

TOD Period Definitions:

1. Summer (Jun-Sep) On-Peak, 4 p.m. to 9 p.m. weekdays,

[18] We computed the TOD Payment Allocation Factors in these tables based upon a three-year (June 2021 to May 2024) average of hourly prices in the CAISO day-ahead market. For locations, we used NP-15 trade hub prices for PG&E, and SP-15 trade hub prices for SCE and SDG&E. We averaged the hourly prices by TOD period, where the TOD periods are as defined for the utilities' respective ReMAT contracts, with the exception of SDG&E where we used QF SOC TOD periods (also the same as TOU-DR1 periods). TOD factors are the ratio of the TOD period average price and the annual average price.

[19] Although SCE already has ReMAT Payment Allocation Factors that differ from 1.0, SCE should update those factors for the ReMAT contract used for the CREP, in order to incorporate recent CAISO energy price data and to be consistent with the TOU factors recommended for the other two IOUs.

2. Summer (Jun-Sep) Mid-peak, Peak 4 p.m. to 9 p.m. weekends and holidays
3. Summer (Jun-Sep) Off-Peak, all hours other than 4 p.m. to 9 p.m. all days
4. Winter (Oct-May) Mid-Peak, 4 p.m. to 9 p.m. all days
5. Winter (Oct-May) Off-Peak, 9 p.m. to 8 a.m. all days
6. Winter (Oct-May) Super Off-Peak, 8 a.m. to 4 p.m. all days.

See Appendix C of REMAT PPA, at:
https://edisonintl.sharepoint.com/:b:/t/Public/TM2/EUcEWuYiG5lNmDlyTCnCga0BloEs0Dz_IgwFbO3JBk4wxg?e=SWp5n3

Table 4: *Revised SDG&E ReMAT Time of Delivery (TOD) Allocation Factors*
These also use the TOD Periods in the QF-SOC and in SDG&E's TOU-DR1 default rate.[20]

Monthly Period	On Peak	Off Peak	Super Off Peak
Summer (Jun – Oct)	1.69	0.93	0.81
Winter (Nov – May)	1.35	0.93	0.83

Summer weekday periods approved in Advice Letter 4344-E for Schedule TOU-DR1 are:

TOU Periods – Weekdays	Summer (June – October)	Winter (November – May)
On-Peak	4:00 p.m. – 9:00 p.m.	4:00 p.m. – 9:00 p.m.
Off-Peak	6:00 a.m. – 4:00 p.m.; 9:00 p.m. - midnight	6:00 a.m. – 4:00 p.m. Excluding 10:00 a.m. – 2:00 p.m. in March and April; 9:00 p.m. - midnight
Super Off-Peak	Midnight – 6:00 a.m.	Midnight – 6:00 a.m. 10:00 a.m. – 2:00 p.m. in March and April
TOU Period –Weekends and Holidays	Summer	Winter
On-Peak	4:00 p.m. – 9:00 p.m.	4:00 p.m. – 9:00 p.m.
Off-Peak	2:00 p.m. – 4:00 p.m.; 9:00 p.m. - midnight	2:00 p.m. – 4:00 p.m.; 9:00 p.m. - midnight
Super Off-Peak	Midnight – 2:00 p.m.	Midnight – 2:00 p.m.

- **Expand project size to 5 MW.** ReMAT is limited to projects up to 3 MW in size. But both SFA funding and some enhanced ITC benefits under the IRA are available for projects up to 5 MW. Establishing 5 MW as the maximum size of CREP projects using

20 SEIA also recommends that the TOU periods in the SDG&E ReMAT PPA should be updated to a current set of TOU periods, such as the one used here – from SDG&E's residential default rate, TOU-DR1. These are also the TOU Periods used in SDG&E's QF-SOC.

the ReMAT contract will help, modestly, for projects to reduce costs through the economies of scale for larger project sizes from 3 MW to 5 MW. SEIA is aware that the Coalition for Community Solar Access (CCSA) will be providing comments that show the modest economies of scale available from 5 MW projects versus 3 MW projects, using the Cost of Renewable Energy Spreadsheet Tool (CREST) model that is in the record of this case.

- **Capacity Adder for solar-plus-storage projects.** Because the ReMAT as-available peaking price is based on a sample of small, solar-only RPS projects, it is not reasonable to expect this solar-only price to cover the costs of solar-plus-storage projects that are twice as expensive and that can provide significant dispatchable, zero-carbon generation capacity. The dispatchable output from the storage component would make solar-plus-storage CREP projects much more valuable to the system, and for ratepayers, than the solar-only projects whose costs set the ReMAT price. To ensure that CREP solar-plus-storage projects provide this greater grid value, they can be required to include 4 hours of storage capacity with a discharge capacity equal to the nameplate of the associated solar (in AC kW), and to be subject to pay-for-performance requirements (discussed below) to earn the adder. For such solar-plus-storage projects, in addition to the ReMAT price for the solar component, ratepayers should fund a Capacity Adder based on the current long-run avoided generation capacity costs for each IOU. The logical source of current long-run avoided generation capacity costs is the approved Avoided Cost Calculator (ACC). In fact, the avoided generation capacity component of the ACC is now based on the fixed costs of utility-scale battery storage,[21] which is precisely the long-run capacity resource that the storage component of these CREP projects will avoid.[22] The Capacity Adder would be expressed in 20-year levelized $ per kW-year, and CREP solar-plus-storage

[21] See D. 22-05-002, at p. 9: "The avoided costs of resource adequacy [i.e. generation capacity] are based on the net cost of new entry (CONE) of four-hour battery storage as the marginal capacity resource."

[22] The 2022 ACC's approved methodology for calculating avoided generation capacity costs based on utility-scale battery storage uses a Real Economic Carrying Charge (RECC) approach. The RECC method is a deferral approach that accounts for the expected future technological progress and associated cost declines for new battery resources. The RECC approach calculates the cost difference of deferring an investment in batteries by one year, and considers the expected decline in battery costs over time to obtain a stream of annual avoided costs for utility-scale batteries.

projects would have the chance to earn the Capacity Adder each year through their performance. **Table 5** shows such 20-year levelized avoided generation capacity costs for 2025-2044 for the three IOUs, from the approved 2022 ACC.[23] In the 2022 ACC, the avoided generation capacity values occur entirely within the three peak summer months of July, August, and September, and are zero in the other nine months. In sum, unless such a Capacity Adder is included for solar-plus-storage projects, the ReMAT price alone will support just solar-only projects and would exclude the hybrid projects that would provide the most value. Because the proposed Capacity Adder is based directly on the avoided generation capacity costs for the battery component of a CREP solar-plus-storage project, it will not cause a cost shift.

Table 5: *2025-2044 Avoided Generation Capacity Costs*

IOU Territory	**2025-2044 Avoided Generation Capacity Costs** *(20-year levelized $ per kW-year)*
PG&E	186
SCE	182
SDG&E	182

- **Pay-for-performance for solar-plus storage projects**. Solar-plus-storage CREP projects would agree to be paid their Capacity Adder based on their performance in 4-hour blocks within the ReMAT on-peak period in the three peak summer months of July, August, and September, with the blocks chosen by the LSE. The Capacity Adder would be paid based on exports to the grid in these 4-hour blocks. The avoided generation capacity costs in Table 5 can be converted to a $ per MWh payment for energy exported during the designated 4-hour blocks in these three summer months, by dividing by the number of hours in the 4-hour blocks (368 total hours in July, August, and September). The utility could have a limited ability, on a day-ahead basis, to change the 4-hour block in which the CREP solar-plus-storage project will discharge its storage. SEIA proposed this flexibility in our December 2024 reply comments prior to the Decision.[24] This

[23] We use the 2022 ACC avoided generation capacity values, levelized over 20 years starting in 2025, for Climate Zone for PG&E, CZ for SCE, and CZ for SDG&E.

[24] See also Exh. SEIA-02, pp. 16-17.

proposal would also be consistent with TURN's position that the utilities should have limited rights to dispatch the storage in community solar projects.[25] On a limited number of critical peak "event days" (e.g. 10 event days per year), the utility would be able to shift the 4-hour block in which CREP projects discharge their power, based on anticipated system conditions. The utility could make such a shift on up to 10 days each year, with notice to the CREP operator on the prior day. This would be similar to how Critical Peak Pricing rates work, except that the hours of the 4-hour peak pricing block would change while the price within that block would stay the same. On the event day, the CREP project would be paid the Capacity Adder based on its output during the new 4-hour peak window, ensuring that the storage would be discharged in that time period when the stored energy is most needed. This would address the concern that, at times, the hours of greatest need for the stored energy from these projects could fall outside of the established ReMAT on-peak period.

- **Low-income Adder to cover low-income subscriber credits.** This adder would come entirely from the incentive funds that are dedicated to low-income community solar subscribers, such as the SFA funding and the $33 million in state funding that the Commission identified in the Decision.
- **Project Adder to cover the remaining costs.** SEIA proposes that CREP projects also would receive a $ per kW upfront Project Adder to cover (1) any remaining developer costs for solar or solar-plus-storage projects plus (2) non-low-income subscriber credits. Like the Low-income Adder, this adder would be funded entirely from available incentive funds. There are several possible ways to establish the Project Adder. The Commission could establish it administratively, using reasonable estimates for remaining developer costs and non-low-income subscriber credits, after considering the revenues from the ReMAT contract and (for solar-plus-storage projects) the Capacity Adder. The necessary Project Adder can be calculated once the Payment Allocation Factors in the ReMAT contract have been updated and the Capacity Adder approved. This would result

[25] See TURN Comments, pp. 3-4. TURN notes that its proposal is that these dispatch rights "should be used primarily to ensure that projects are available during extreme grid conditions when the availability of additional supply would have highest value."

in the CREP becoming a "walk-up" program available on a first-come, first-served basis. Alternatively, LSEs could conduct reverse auctions to award Project Adders to projects that require the least amounts of incentive funds.

- **Treatment as a load modifier for resource adequacy.** The California Energy Commission (CEC) is the agency responsible for developing load forecasts and load modifier determinations. Subject to CEC approval, CREP projects could be treated as load modifiers in the CEC's IEPR demand forecast. This would ensure that LSEs who participate in CREP would receive RA capacity value for their CREP projects, when they use the modified IEPR demand forecast to submit their load forecasts during the RA compliance process. This will also ensure that the output of CREP projects is included, for planning and GHG emission reduction purposes, in the Integrated Resource Planning (IRP) process that also is driven by the CEC IEPR demand forecast. Under this option, CREP projects would provide capacity value upon commercial operation – without the delays, significant expense, and risk of the CAISO's interconnection and deliverability processes that are particularly difficult for these small projects to navigate. This capacity value would be based on CREP projects' ability to consistently reshape and reduce system demand, such that the forecasted demands that drive RA requirements are systematically lower than what they would have been but for the projects' load-modifying output. SEIA proposes that solar-plus-storage projects should be required to achieve load modifier status in order to qualify to receive the Capacity Adder. This requirement, plus the pay-for-performance structure that SEIA has proposed above, ensure that CREP solar-plus-storage projects would only receive compensation for the avoided generation capacity value that they demonstrably deliver to ratepayers.

2. **Decision (D.)24-05-065 states, "The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit." What should the revenue share for low-income subscribers be and how should it be calculated? Comments should consider that some external funding types may have certain conditions to ensure the funding benefits low-income customers.**

Response. The issue with the Decision's preliminary finding of a minimum 20% revenue share is that it does not consider the SFA requirements, which mandate a significantly higher

20% <u>bill savings</u> for low-income subscribers. The EPA has stated that the 20% savings requirement for SFA projects is measured off the average utility bill in the service territory. The EPA's *Notice of Funding Opportunity* (NOFO) for the SFA program defines Household Savings as:

> **Household Savings**: Delivering a minimum of 20% household savings to all households served under the program, including households in multi-family, master-metered buildings; 20% household savings is defined as 20% of the average household electricity bill in the utility territory. Household savings can be delivered as a direct financial benefit or, for households without an individual utility bill, a direct non-financial benefit equivalent in value to the program's household savings target in the utility territory. Additional detail on how to calculate household savings is included in Appendix C: Household Savings Guidance. Applicants may propose preliminary estimates in the financial assistance model for household savings and explain how they plan on refining those estimates during the first year of the program if more analysis is needed. EPA expects to work with grantees to refine estimates for household savings.[26]

To comply with these SFA requirements, the amount of SFA incentive funds set aside for each CREP project's low-income credits should be the net present value over 20 years of 20% of the current CARE rate times the average annual CARE usage in the service territory.

With respect to low income credits not funded by the SFA, the Decision's tentative proposal of 20% of project revenues fails to consider that a more expensive solar-plus-storage project would produce significantly greater credits than a solar-only project. 20% of the project revenues for a solar-only project with revenues of $0.10 per kWh is $0.02 per kWh; while 20% of the project revenues for a solar-plus-storage project with revenues of $0.18 per kWh is $0.036 per kWh. Thus, with limited incentive funds, the standard of 20% of project revenues would push LSEs to contract with less expensive but less valuable solar-only projects, so that the constrained incentive dollars go further. To avoid this result and to provide a reasonable

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26 See EPA, SFA NOFO, at p. 12.

opportunity for more valuable solar-plus-storage projects, SEIA recommends a standard low-income credit of $0.03 per kWh for the use of non-SFA incentive funds that do not prescribe a minimum subscriber credit. At current rates, this $0.03 per kWh credit would provide a meaningful 10% to 13% bill savings for the average CARE customer of the three IOUs. $0.03 per kWh would be 30% of project revenues for a solar-only CREP project costing $0.10 per kWh, and 17% of project revenues for a solar-plus-storage project costing $0.18 per kWh.

3. **D.24-05-065 states "With respect to bill credits, the Commission finds the [Southern California Edison (SCE)] proposal to use the simplified Shared Savings Model using balancing accounts to provide a flat monetary credit on subscriber bills is reasonable…The Commission finds that a minimum 20 percent revenue share for low-income subscribers is reasonable and provides protection for subscribers. However, the record of this proceeding does not contain adequate details on a specific percentage credit. A future ruling in this proceeding will allow for additional record development. The Commission also declines to specify a minimum revenue share for non-low-income- subscribers as they will not receive a subsidy through external funding." Propose, in detail, how a low-income and non-low-income bill credit should be applied, including bill presentment.**

Response. Again, as explained above, the low-income subscriber bill credit should be based on providing 20% annual bill savings with SFA funds, or a bill credit of $0.03 per kWh if other less-constrained incentive funds are used. The incentive funds should be used to provide a flat dollar credit each month, with the monthly credit based on either (1) 20% of the average CARE residential rate on January 1 each year times the average monthly CARE usage, if SFA funds are used, and (2) the standard $0.03 per kWh low-income incentive times the average monthly CARE usage, if other incentive funds are used. Thus, each low-income subscriber would receive the same credit each month, in dollars, which preserves the price signal in retail rates for customers to moderate their incremental usage during peak periods. The CREP tariff should provide for full payments to subscribers if a project's output in a year is at least 90% of the expected output as stated in the ReMAT PPA. If a project fails to reach this output level in a given year, subscriber payments in the subsequent year could be reduced by the percentage shortfall in output compared to the benchmark of 90% of expected production.

B. Non-Ratepayer-Funded Adder

4. What should be the developer incentive or adder per project and how should it be calculated? Potential funding sources include the Environmental Protection Agency's (EPA) Solar for All grant funding, General Funds allocated to the Commission, and others to be determined.

Response. SEIA appreciates the Commission's recognition in the Ruling that a Project Adder for developers will be needed to make CREP projects economic under the ReMAT contract. We have proposed above several possible mechanisms for determining this adder – either administratively or based on competitive bids from developers.

a. Should the incentives for developers be based on dollars per watt, dollars per kilowatt-hour, a lump sum, or some other scheme? Explain why.

Response. The Project Adder, funded from non-ratepayer monies, should be in $ per kW, and paid to the CREP project upfront. The Project and Capacity Adders, plus the fixed price in the ReMAT contract, will provide the certainty needed to finance CREP solar-plus-storage projects. LSEs would retain and administer the incentive funds used for each project's Low-income Adder, to provide the required monthly bill credit to low-income subscribers.

b. What process should the Commission use for determining the incentive or adder? Should the Commission set the incentive or adder price administratively or should it require the utilities to use a method such as a reverse auction that would introduce price discovery? If you recommend a price discovery method, specify the method you propose and the justification for using that method.

Response. It is apparent that external incentive funds will be limited. In addition, the SFA funding requires significantly larger low-income subscriber credits than contemplated in the Decision, which further limits the number of CREP projects that can be developed. SEIA provides calculations in **Attachment SEIA-1** which show that, due to the SFA requirements for low-income subscriber credits and an assumed $125 million pool of SFA funds for community solar (50% of the SFA funds awarded to California), the total MW of CREP projects will be limited to 206 MW if all projects use tracking arrays, and 245 MW if all projects are fixed arrays. This also assumes that each CREP project has the minimum 51% of capacity subscribed by low-income customers and includes the use for low-income credits of the $33 million in state funds identified in the Decision. As a result, there needs to be an equitable means to ration and to allocate the scarce incentive dollars so that they support as many projects as possible. For this reason, SEIA is willing to support a reverse auction as one fair and feasible method for LSEs to allocate their available incentive funds to the projects that can minimize their use. As noted in Question 4.b, this would also provide important price discovery on the costs for these small solar and solar-plus-storage projects. Alternatively, the Commission could set Project Adders for both solar-only and solar + storage projects administratively, based on estimates of the additional funding needed (1) to make projects viable economically and (2) to provide non-low-income subscriber credits. This would result in a "walk-up" CREP where funding would be allocated on a first-come, first-served basis to projects that have met certain development milestones.

c. Should the incentive or adder be based on a minimum dollar amount per customer or a minimum percentage of project revenue share? Should the incentive or adder increase if more low-income customers are signed up beyond the 51 percent per project minimum threshold?

Response. With respect to the incentive funds for subscribers, all of the funds for the subscriber credits are likely to come from a limited pool of non-ratepayer incentive funds. As a result, a project that serves more than 51% low-income customers would require a larger allocation of incentive funds, because the low-income credits will be greater than the non-low-income credits. Allowing CREP projects to serve substantially more than 51% low-income customers could become an issue, if the Commission is concerned with stretching the limited external funds to serve as many CREP projects as possible. LSEs may want to cap the share of low-income subscribers at a level above 51%, for example at 60% of subscribers, in order to spread the limited incentive funds over the largest possible number of CREP projects. It also will be important to ensure that some community solar capacity is available to non-low-income subscribers, because the program must support other statutory goals such as providing an alternative, less expensive compliance pathway for California's Title 24 rooftop solar mandate.

d. What other non-monetary incentives or assistance could utilities or Community Choice Aggregators (CCAs) provide to community renewable energy program projects and developers?

Response. SEIA welcomes any creative assistance that utilities or Community Choice Aggregators (CCAs) could provide to CREP projects. A CCA could propose to provide additional incentive funds to CREP projects in its service territory, or a utility with surplus land near a substation could provide a site for a CREP project, thus lowering project costs and reducing the incentive funds needed for that project. Finally, a housing developer might be willing to contribute to incentive funds for new homes that will meet their Title 24 solar requirements through a specific CREP project, if that contribution is less than the cost of including on-site solar in the homes. The IOUs and CCAs could consider giving preference in allocating CREP subscriptions to new homes whose developers contribute to CREP incentive funding.

C. Federal Incentives

5. **Some CCAs who administer the Disadvantaged Communities Green Tariff (DAC-GT) have successfully negotiated lower Power Purchase Agreement contract prices with selected developers if a project receives the federal Investment Tax Credit (ITC) Low-Income Community Bonus Credit. Similarly, the Solar on Multifamily Affordable Housing program also set a precedent for aligning incentives, such as the federal ITC, with incentives provided for the installation of solar. Should the new**

community renewable energy program follow a similar process for leveraging the federal incentives available in the Inflation Reduction Act including the Low-Income Community Bonus Credit and other new and available tax credits.

Response. SEIA does not expect that many projects will qualify for the enhanced federal tax incentives, given the limited amount of such credits available and the use of a lottery to allocate them. Nonetheless, if a CREP project qualifies for the federal Low-Income Community Bonus ITC, that project should receive priority in the allocation of incentive funds, provided that such projects show that they have passed a substantial portion of the value of the credit through to subscribers and ratepayers. This showing could be in the form of (1) foregoing any Project Adder and (2) for solar-plus-storage projects, a reduction in the Capacity Adder. The savings from the lower Project Adder could be used to support low-income subscriber credits. Similarly, if a solar-plus-storage project with access to a 50% Bonus ITC agrees to take a Capacity Adder that is less than the current avoided generation capacity cost, the savings in ratepayer costs also could be used to fund additional low-income subscriber credits. This aspect of SEIA's proposal would provide a strong boost to CREP projects in disadvantaged communities that qualify for the Low-Income Community Bonus ITC. This is consistent with AB 2316, which states that "the Commission is required to ensure that the community renewable energy program facilities are eligible for an enhanced federal ITC available as a qualified low-income economic benefit project."[27] If a project receives the enhanced ITC, it should reduce the amount of other outside money that is needed.

D. Disbursal of Non-Ratepayer Funds

6. **D.24-05-065 states "Utilities would have the role of fiscal agents and apply monetary credits to the generation, i.e., benefiting, and customer, i.e., subscriber, accounts. The Commission finds that it is reasonable to direct Utilities to establish a balancing account to track the subscriber revenue shares and distribute the appropriate shares**

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27 See P.U. Code Section 769.3(c)(6).

through the bill credit. Further, changes to the credits based on facility performance and credit distribution can be easily updated through an annual true-up process." How should the external funding be disbursed to the projects and participating customers of Utilities and CCAs?

Response: The funds should be disbursed to subscribers in a monthly lump sum. The IOU or the CCA can track the amounts paid out to subscribers of the project over the project life through a balancing account.

E. Treatment of Utility Implementation and Administrative Costs

7. **What funding source should be used to pay for start-up costs and program administration and what process should be used for cost recovery? This may include costs associated with billing system updates, the customer enrollment process buildout, ongoing subscription management and development of a new solar and storage contract (if needed).**

Response: Today, LSE's fund through regular rates their administrative costs for programs for individual solar customers (i.e. NEM and NBT). As a matter of fairness, the same treatment also should be extended to the implementation and administrative costs for the new community solar program. Further, the administrative costs for the existing low-income community solar programs are funded from general rates. This will also make more incentive dollars available to support CREP facilities, because, absent this treatment, implementation and administrative costs would have to come from limited incentive funds.

8. **D.24-05-065 states "As CCAs are permitted to participate in the new community renewable energy program, the foundational tariffs will need to be revised to accommodate this participation. At this time, the record does not contain the specifics for CCA participation."**

    a. **What process should be employed to enable CCA participation in the community renewable energy program? This would include discussion of how CCAs must notify the Commission of their participation in accordance with Pub. Util. Code Section 769.3(b)(2)(B) and the process for CCAs to access external funds?**

Response: CCAs should be full-fledged participants in the CREP. The Decision approved a CREP that is based entirely on wholesale generation tariffs and contracts. One of the CCAs' core competencies is the procurement of wholesale generation and the management of power purchase agreements. CCAs have full responsibility for managing the generation procurement and generation costs of their customers. CCAs are public, locally-governed entities that are closer and more responsive to the cities, counties, and communities that they serve than the larger, shareholder-owned, profit-maximizing IOUs.

Accordingly, a CCA that provides notice of their desire to participate in CREP, pursuant to Code Section 769.3(b)(2)(B), should be allocated a proportional share of any federal and state incentive funds for community solar. These shares of incentive funds should be allocated annually according to the load shares of the CCAs that desire to participate. CCAs should have full authority to manage their own CREP procurement and the disbursement of their share of incentive funds to projects and subscribers.

b. Which CCA tariffs should be eligible for the program?

Response: CCAs should have the flexibility to manage their own CREP programs. This should include: (1) prescribing the form of the contract with developers, (2) conducting solicitations for CREP projects, and (3) allocating and managing their shares of state and federal incentive funds. CCAs will face the same SFA low income subscriber requirements as the IOUs, in terms of how those federal funds must be used. The Commission should direct the IOUs to cooperate with CCAs in the customer billing for both the IOU and CCA CREP programs.

F. Reporting Requirements

9. **Parties raised concerns about the community renewable energy program in relation to reporting requirements for the Low-Income Communities Bonus Credit Program and EPA Solar for All in their comments on the draft proposed decision. How should the Commission account for reporting for various potential tax incentives**

and funding types? How should the Commission incorporate this efficiently into the community renewable energy program design?

Response. Low-Income Communities Bonus Credit (LICBC) projects are required to submit a list of households or other entities served with name, address, subscription share, and income status of qualifying low-income households served, and the income verification method used.[28] It is not clear how the developer would comply with this if the IOUs auto-enroll subscribers (who then can opt out); it is also unclear under auto enrollment which customers are "assigned" to which project. It appears preferable for the utility or CCA to assign customers to a project on a first-come-first-served basis (i.e., customers on the top of the list will be assigned to the first project, etc.), and then to provide the developer with the list and contact information for the customers (after the opt-out period), so that the developer has the necessary information for LICBC qualification and for compliance purposes.

G. Enrollment

10. Should Utility-facilitated or CCA-facilitated auto-enrollment be the only enrollment pathway for low-income customers in DAC-GT and the new community renewable energy program? What other enrollment options are available? What are the benefits or drawbacks of either approach? Comments should consider potential administrative cost, alignment with other low-income programs like the California Alternate Rates for Energy (CARE) program, compatibility with Title 24, the customer enrollment experience, ease of customer understanding billing/crediting, and consumer protections.

Response: In listing the elements of the new CREP, Ordering Paragraph 1 (e) provides:

> Automatic Enrollment — Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall implement the same auto-enrollment procedures as approved by the Commission in Decision 20-07-008 and Resolution E-5124. [29]

The criteria for auto-enrollment specified in D. 20-07-008 are:

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[28] See 26 CFR § 1.48(e)-1(f)(3).

[29] Decision 24-05-065, Ordering Paragraph 1(e), p.168.

- Located in one of the statewide CalEnviroScreen top 15 percent census tracts located qin [the IOU's] service territory;
- Eight or more late payment notices triggering three to six collection processes per year;
- Two or fewer "Return to Maker" payments (i.e., returned checks);
- Two or fewer disconnections within 12 months;
- Six or more payments within the last 12 months (indicating a customer's effort to pay); and
- Total Balance Owing" is greater than $0 (with no credit balance on account).[30]

Given these parameters, the population of customers which will be auto enrolled is smaller than the number of low-income customers receiving service from the IOU (as defined in P.U. Code Section 769.3 (a)(3)). With respect to these other low-income customers, SEIA does not believe auto-enrollment is necessary. If applying the criteria specified in D. 20-07-008 does not result in sufficient enrollment to fulfill the statutory requirement that 51 percent of the program's capacity serves low-income customers, then the project owner should be responsible for finding the additional low-income subscribers, with the same consumer protections that CCSA proposed in its testimony.[31] However, given California's critical need for new housing, the Commission should provide an enrollment preference for low-income customers in new housing developments that are using CREP to meet Title 24 solar requirements.

The Decision also implied that CCAs who chose to participate in the CREP would be required to employ auto-enrollment for qualified low-income customers.[32] SEIA is not opposed to CCAs implementing such an auto-enrollment process, subject to the same caveats expressed above with respect to the IOUs.

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[30] Decision 20-07-008, p. 13, Ordering Paragraph 1.

[31] Exh. CCSA-01, pp. 53-66.

[32] Decision, 24-05-065, p. 119 ("low-income subscribers meeting each Utility or CCA's Arrearage Management Program enrollment criteria will be prioritized for automatic enrollment.").

For Title 24 compliance, the alternative to a viable CREP is additional rooftop solar projects under the Net Billing (NBT) and the virtual net metering (VNEM) tariffs. As TURN highlighted, "[u]nder NBT and VNEM, a large share of generation output would be treated as residential self-consumption and compensated at retail rates. Exports would be compensated at the ACC values plus the 9-year adders adopted in D.22-12-056 (for NBT) and D.23-11-068 (for VNEM)."[33] If a viable CREP program is not implemented, the lost revenues from the additional NBT and VNEM rooftop solar projects needed for Title 24 compliance will significantly exceed the alternative costs of implementing SEIA's recommended CREP. SEIA has looked at the bill savings / lost revenues for the NBT based on the E3 model that the CPUC used in its NBT decision, D. 22-12-056, and reported on pages B5 and B5 of Appendix B to that order. These results are shown in the second and third columns of **Table 6**. The fourth and fifth columns show the same bill savings using updated 2024 rates.

Table 6: *NBT Bill Savings / Lost Revenues for Residential Systems ($ per kWh)*

Utility	D. 22-12-056, Appendix B, E3 Model using 2022 rates		E3 Model updated, using 2024 rates	
	Solar-only	Solar + Storage	Solar-only	Solar + Storage
PG&E	$0.16	0.34	$0.20	$0.43
SCE	$0.15	0.31	$0.17	$0.37
SDG&E	$0.23	0.44	$0.20	$0.31

These bill savings / lost revenues are well above the costs for the CREP projects that the Commission is now designing, which are $0.09 to $0.12 per kWh for solar-only and $0.18 to $0.20 per kWh for solar-plus-storage.[34] Thus, the viable CREP program that SEIA has proposed

33 See TURN Opening Comments on Proposed Decision, at p. 12.

34 See the data in Footnotes 7 and 8 above. These CREP costs do not include subscriber credits, which will add roughly $0.02 to$0.04 per kWh to overall CREP costs, assuming non-low-income credits of $0.01 per kWh and low-income credits of $0.03 to $0.06 per kWh.

is a less expensive means to provide for Title 24 compliance than actually installing solar or solar-plus-storage systems under the NBT.

11. **If you recommend auto-enrollment, describe the criteria that should be used for i) determining which customers would be auto-enrolled in the community renewable energy program and ii) ensuring that customers aren't enrolled in more than one program (i.e. community renewable energy program and DAC-GT). Additionally, explain which program (i.e. community renewable energy program and DAC-GT) would low-income customers be enrolled in first.**

Response: Low-income customers who meet the criteria set forth in D. 20-07-008 should be auto-enrolled in either DAC-GT or the CREP on a non-discriminatory, first-come-first-served basis, with the IOUs and CCAs cooperating to ensure that customers are enrolled in only one program. As the IOUs and CCAs will be the ones effecting the auto-enrollment, they should check that safeguards are put in place to ensure that double enrollment does not occur.

We support the Decision's application of the same criteria for placement in both of the programs and do not take a position into which program customers should be enrolled first. As noted above, the Commission should provide an enrollment preference for low-income customers in new housing that is using CREP to meet Title 24 solar requirements.

III. CONCLUSION

SEIA welcomes this opportunity to continue to work with the Commission to design a workable and sustainable community solar program that benefits the grid and all ratepayers, and that allows a broader range of ratepayers to benefit from locally-sited, distributed solar resources. It is particularly important to design a reasonable CREP that can successfully leverage the available non-ratepayer funding for community solar.

Respectfully submitted, this 10th day of July 2024, at San Francisco, California.

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By *___/s/ Jeanne B. Armstrong___*
Jeanne B. Armstrong

Attachment SEIA-1

Maximum MW of CREP Projects

Utility	Fixed	Tracking
PG&E	102	85
SCE	122	103
SDG&E	21	18
Total	245	206

PG&E

CREP Projects

		Value	Units	*Notes*
Assumed CREP project size		5.0	*MW-AC*	
Capacity factor		22.6%		*Fixed array, PV Watts, Fresno CA*
		27.1%		*Single-axis tracker, PV Watts, Fresno CA*
Annual output		9,893	*MWh*	*Fixed array*
		11,858	*MWh*	*Single-axis tracker*

Present Value Adjustment

		Value	Units	*Notes*
Annual rate escalation		4.0%	*per year*	*CPUC standard assumption*
Discount rate		7.3%		*PG&E 2023 WACC per D. 22-12-031*
Assumed project life		20	*years*	
20-yr NPV Adjustment Factor		14.12		

SFA Federal Incentive Funds

		Value	Units	*Notes*
Available SFA/LI incentive funds		125	*$ millions*	*50% of SFA funds awarded to CA*
NorCal LSEs' share of funds		45%		*PG&E territory LSEs' load share*
PG&E E-TOU-C default rate	$	0.4541	*per kWh*	*June 1, 2024 average rate*
CARE discount		-35.0%		
PG&E E-TOU-C CARE rate	$	0.2952	*per kWh*	
20% of average CARE rate	$	0.0590	*per kWh*	*Required SFA bill savings for LI customers*
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0301	*per kWh of project output*	
Minimum LI credits, per year, for	$	0.30	*$ millions/year*	*Fixed array*
one project	$	0.36	*$ millions/year*	*Single-axis tracker*
20-yr NPV of minimum LI credits	$	4.2	*$ millions*	*Fixed array*
	$	5.0	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits,	$	0.84	*$ millions/MW*	*Fixed array*
per MW	$	1.01	*$ millions/MW*	*Single-axis tracker*
Max amount of PG&E CS capacity		67	*MW*	*Fixed array*
		56	*MW*	*Single-axis tracker*

State Incentive Funds

		Value	Units	*Notes*
Available state incentive funds		33	*$ millions*	*per D. 24-05-065, at p. 118*
NorCal LSEs' share of funds		45%		*PG&E territory LSEs' load share*
State LI credits	$	0.03	*per kWh of project output*	
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0153	*per kWh of project output*	
Minimum LI credits, per year, for	$	0.15	*$ millions/year*	*Fixed array*
one project	$	0.18	*$ millions/year*	*Single-axis tracker*
20-yr NPV of minimum LI credits	$	2.1	*$ millions*	*Fixed array*
	$	2.6	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits,	$	0.43	*$ millions/MW*	*Fixed array*
per MW	$	0.51	*$ millions/MW*	*Single-axis tracker*
Max amount of PG&E CS capacity		35	*MW*	*Fixed array*
		29	*MW*	*Single-axis tracker*

SCE

CREP Projects

		Value	Units	Notes
Assumed CREP project size		5.0	*MW-AC*	
Capacity factor		22.9%		*Fixed array, PV Watts, Ontario CA*
		27.1%		*Single-axis tracker, PV Watts Ontario CA*
Annual output		10,034	*MWh*	*Fixed array*
		11,859	*MWh*	*Single-axis tracker*

Present Value Adjustment

		Value	Units	Notes
Annual rate escalation		4.0%	*per year*	*CPUC standard assumption*
Discount rate		7.4%		*SCE 2023 WACC per D. 22-12-031*
Assumed project life		20	*years*	
20-yr NPV Adjustment Factor		13.91		

SFA Federal Incentive Funds

		Value	Units	Notes
Available SFA/LI incentive funds		125	*$ millions*	*50% of SFA funds awarded to CA*
SoCal LSEs' share of funds		46%		*SCE territory LSEs' load share*
SCE residential rate	$	0.3340	*per kWh*	*SCE Advice 5235-E, average bundled res. rate*
CARE discount		-30.0%		
SCE CARE rate	$	0.2338	*per kWh*	
20% of average CARE rate	$	0.0468	*per kWh*	*Required SFA bill savings for LI customers*
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0238	*per kWh of project output*	
Minimum LI credits, per year, for one project	$	0.24	*$ millions/year*	
	$	0.28	*$ millions/year*	
20-yr NPV of minimum LI credits	$	3.3	*$ millions*	*Fixed array*
	$	3.9	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits, per MW	$	0.67	*$ millions/MW*	*Fixed array*
	$	0.79	*$ millions/MW*	*Single-axis tracker*
Max amount of SCE CS capacity		86	*MW*	*Fixed array*
		73	*MW*	*Single-axis tracker*

State Incentive Funds

		Value	Units	Notes
Available state incentive funds		33	*$ millions*	*per D. 24-05-065, at p. 118*
SoCal LSEs' share of funds		46%		*SCE territory LSEs' load share*
State LI credits	$	0.03	*per kWh of project output*	
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0153	*per kWh of project output*	
Minimum LI credits, per year, for one project	$	0.15	*$ millions/year*	*Fixed array*
	$	0.18	*$ millions/year*	*Single-axis tracker*
20-yr NPV of minimum LI credits	$	2.1	*$ millions*	*Fixed array*
	$	2.5	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits, per MW	$	0.43	*$ millions/MW*	*Fixed array*
	$	0.50	*$ millions/MW*	*Single-axis tracker*
Max amount of SCE CS capacity		36	*MW*	*Fixed array*
		30	*MW*	*Single-axis tracker*

SDG&E

CREP Projects

	Value	Units	Notes
Assumed CREP project size	5.0	*MW-AC*	
Capacity factor	22.0%		*Fixed array, PV Watts, San Diego CA*
	25.4%		*Single-axis tracker, PV Watts, San Diego CA*
Annual output	9,619	*MWh*	*Fixed array*
	11,145	*MWh*	*Single-axis tracker*

Present Value Adjustment

	Value	Units	Notes
Annual rate escalation	4.0%	*per year*	*CPUC standard assumption*
Discount rate	7.2%		*SDG&E 2023 WACC per D. 22-12-031*
Assumed project life	20	*years*	
20-yr NPV Adjustment Factor	14.23		

SFA Federal Incentive Funds

		Value	Units	Notes
Available SFA/LI incentive funds		125	*$ millions*	*50% of SFA funds awarded to CA*
SDG&E LSEs' share of funds		9%		*SDG&E territory LSEs' load share*
SDGE residential rate	$	0.4038	*per kWh*	*SDG&E Advice 4344-E, class average res. rate*
CARE discount		-30.0%		
SDG&E CARE rate	$	0.2826	*per kWh*	
20% of average CARE rate	$	0.0565	*per kWh*	*Required SFA bill savings for LI customers*
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0288	*per kWh of project output*	
Minimum LI credits, per year, for one	$	0.28	*$ millions/year*	
project	$	0.32	*$ millions/year*	
20-yr NPV of minimum LI credits	$	3.9	*$ millions*	*Fixed array*
	$	4.6	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits,	$	0.79	*$ millions/MW*	*Fixed array*
per MW	$	0.91	*$ millions/MW*	*Single-axis tracker*
Max amount of SDG&E CS capacity		14	*MW*	*Fixed array*
		12	*MW*	*Single-axis tracker*

State Incentive Funds

		Value	Units	Notes
Available state incentive funds		33	*$ millions*	*per D. 24-05-065, at p. 118*
SDG&E LSEs' share of funds		9%		*SDG&E territory LSEs' load share*
State LI credits	$	0.03	*per kWh of project output*	
Minimum LI share of credits		51%		*per AB 2316*
Minimum LI credits	$	0.0153	*per kWh of project output*	
Minimum LI credits, per year, for one	$	0.15	*$ millions/year*	*Fixed array*
project	$	0.17	*$ millions/year*	*Single-axis tracker*
20-yr NPV of minimum LI credits	$	2.1	*$ millions*	*Fixed array*
	$	2.4	*$ millions*	*Single-axis tracker*
20-yr NPV of minimum LI credits,	$	0.42	*$ millions/MW*	*Fixed array*
per MW	$	0.49	*$ millions/MW*	*Single-axis tracker*
Max amount of SDG&E CS capacity		7	*MW*	*Fixed array*
		6	*MW*	*Single-axis tracker*