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Application of PACIFIC GAS AND ELECTRIC COMPANY (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	Application 22-05-022 (Filed May 31, 2022)
And Related Matters	Application 22-05-023 Application 22-05-024

OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON THE ADMINISTRATIVE LAW JUDGE RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

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OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON THE ADMINISTRATIVE LAW JUDGE RULING DIRECTING RESPONSES TO QUESTIONS REGARDING IMPLEMENTATION OF DECISION 24-05-065

Pursuant to the June 5, 2024 Ruling of Administrative Law Judge Hymes, The Utility Reform Network (TURN) submits these opening comments providing responses to questions regarding the implementation of Decision 24-05-065. In a June 13th ruling by ALJ Hymes, the deadline for comments was extended to July 10th. TURN offers responses to selected questions posed in the Ruling.

I. INTRODUCTION

A. Reliance on ReMAT and PURPA without modifications is unlikely to yield successful new project development

The Commission intends to rely on the Renewable Energy Market Adjusting Tariff (ReMAT) and PURPA Standard Offer contract program as the basis for developing community renewable energy projects. One significant problem with this approach is the fact that these programs have failed to produce any material quantity of new renewable energy projects in recent years. Since 2017, the ReMAT program has resulted in only a single new solar project achieving commercial operation. [1] There have been no new renewable energy projects successfully developed pursuant to the PURPA Standard Offer contract in approximately 30 years.[2] The problem appears to be

[1] CPUC RPS Public Database, June 2024 (https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2024/rps-public-database---june-2024.xlsx). There are currently four projects that executed ReMAT agreements in 2023 and are listed as "in development" but there is no indication as to whether they are likely to achieve commercial operations. Four other projects that executed ReMAT agreements in 2021 have already terminated their agreements.

[2] CPUC RPS Public Database, June 2024 (https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2024/rps-public-database---june-2024.xlsx). The last project developed under a PURPA standard offer contract appears to be Salton Sea IV which executed a contract in 1994. Although other projects have executed short-term QF standard offer contracts since that time, those projects were already operating at the time the contract was executed. There are currently three solar projects that executed QF standard offer contracts in 2022 and are "in development" but there is no indication as to whether they are likely to achieve commercial operations.

inadequate pricing offered to project developers that does not enable financing on terms that are acceptable to investors and lenders.

New resource development has been occurring primarily through procurement driven by the Integrated Resource Planning (IRP) and Renewable Portfolio Standard (RPS) programs. Pricing under these programs is set through competitive market transactions rather than via administratively-determined values (as is the case under PURPA and ReMAT). There is no evidence that prices for resources procured through the IRP and RPS programs are comparable to the ReMAT and QF Standard Offer contracts. <u>TURN recommends that each Investor-Owned Utility (IOU) and Community Choice Aggregator (CCA) participating in this proceeding be directed to submit pricing (under seal) for all contracts executed in the last five years with new small-scale renewable energy and storage projects (<20 MW).</u> This information would be helpful in allowing the Commission to assess the extent to which additional financial support is needed to enable project developers to participate in the Community Renewable Energy Program (CREP).

Unless the Commission grapples with the fundamental challenges of creating financeable contracts, there is little hope that developers will be able to participate in the CREP. Evaluating the minimum thresholds for financeable contracts as part of program design should be a primary focus of this phase of the proceeding.

B. The Commission should ensure that the adopted program serves as an effective alternative compliance option under Title 24

The Commission should prioritize the use of the CREP as an alternative compliance option to the Net Billing Tariff (NBT) program under the Title 24 new residential building standards. The alternative compliance option allows reliance on a community solar program but is contingent upon satisfying various criteria including 20 years of bill savings.[3] Absent a viable community solar program, Title 24 compliance will be met

[3] TURN opening brief, pages 32-33, footnote 85 (2019 Building Energy Efficiency Standards, Title 24, Part 6, Section 10-115(a)(2), (3), (4), (5)).

entirely with rooftop projects under NBT and Virtual Net Energy Metering (VNEM) tariffs. Under 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 Avoided Cost Calculator (ACC) values plus the 9-year adders adopted in D.22-12-056 (for NBT) and D.23-11-068 (for VNEM and NEMA). The use of NBT and VNEM to satisfy Title 24 compliance would be vastly more expensive than a viable community renewable energy program alternative.

As noted in the prior phase of this proceeding, the California Building Industries Association estimates that 250-400 MW of community solar facilities are needed annually to serve as compliance option for Title 24 requirements.[4] TURN used the Net Billing Tariff (NBT) model created by the Commission's Energy Division in R.20-08-020 to estimate 25-year participant bill savings per kW of installed rooftop solar paired with an assumed 4 hours of energy storage and 4% annual rate escalation.[5] The model calculates that 1,000 MW of new rooftop solar with 4-hour paired storage installed by non-CARE residential customers would result in $20.425 billion in participant bill savings over the course of 25 years assuming 470 MW in SCE's service territory, 430 MW in PG&E's service territory, and 100 MW in SDG&E's service territory. By comparison, PG&E previously forecast the cost for 1,000 MW of solar (with the same allocation amongst the IOUs) paired with 4 hours of energy storage developed under the Net Value Billing Tariff (NVBT) and PURPA Standard Offer contracts. The PG&E analysis forecasts that this same quantity of solar plus storage would cost $13.627 billion under the NVBT and $5.560 billion under Standard Offer contracts.[6] The Commission relied on PG&E's analysis in support of its findings in D.24-05-065.[7]

Comparing the cost of Title 24 under the Net Billing Tariff to potential outcomes under CREP demonstrates the opportunity for very meaningful cost reductions that benefit all

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[4] CBIA opening brief, page 7.
[5] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nemrevisit/nbt-model--12142022.xlsb
[6] PG&E Surrebuttal Testimony, pages 6-7.
[7] The PG&E calculations are included in Appendix A to D.24-05-065.

ratepayers. Using PG&E's math, the NVBT would be expected to result in $6.798 billion in savings relative to NBT while the PURPA Standard Offer contract would result in $14.865 billion in savings. TURN doubts that the PURPA Standard Offer pricing is realistic absent enhancements given the absence of participation by developers. Consequently the Commission should recognize the substantial potential savings to be gained through the adoption of a robust CREP that can serve as alternative compliance under Title 24. Failing to provide a viable community renewable energy alternative to NBT would cause significant harm to all ratepayers.

This phase of the proceeding should be devoted to the development of a community renewable energy program that will quality as Title 24 alternative compliance, will induce participation by renewable project developers and homebuilders, and can bring down the total costs borne by all customers.

C. All eligible projects should include 4 hours of energy storage

TURN previously explained the importance of requiring all eligible renewable energy projects participating in the CREP to include four hours of energy storage at the same rated capacity as the generating unit. The significant value of paired energy storage would assist with resource adequacy obligations (either as a load modifier or if the project is assigned Net Qualifying Capacity) and ensure that generation can be dispatched to serve net peak system needs. Adding more stand-alone solar without paired storage would represent a missed opportunity and only exacerbate the existing challenges of intermittent resource curtailment and low mid-day wholesale pricing.

The Commission did not directly address the need for paired storage in D.24-05-065. In this phase of the proceeding, the Commission must clarify that paired storage is required and not optional. Absent such a clarification, TURN expects that virtually none of the new capacity added under the CREP would include storage. To remedy this potential defect, the requirement should be added and included in modeling assumptions used to determine revenue adequacy and project benefits to the overall system.

To effectuate this requirement, the Commission must grapple with the fact that the existing PURPA and ReMAT pricing is not designed to provide adequate compensation to projects that incorporate energy storage. Compensation should, therefore, incorporate a Resource Adequacy (RA) value that approximates the benefits provided to the grid and all customers. Furthermore, the Commission should adopt TURN's original proposal to require that project storage be subject to dispatch instructions by the CAISO, the local utility or the CCA contracting with the project. Having dispatch control over paired storage would optimize the overall value of the resource and justify higher ratepayer-funded revenues.

D. TURN reverse auction straw proposal

The Commission should consider a structure for the selection of new CREP resources that uses ReMAT/PURPA pricing as a starting point but incorporates several additional elements that will optimally use external funding, recognize and capture the value of storage, and introduce a competitive process through a reverse auction to minimize resource cost. These features should incentivize the development of the most cost-effective projects that provide highest value to the grid. The key elements of such a proposal are as follows:

- Eligible projects should be sized at no more than 10 MWs to balance scale efficiencies with suitability for distribution-level interconnection.[8]

- Eligibility should be limited to projects that include 4 hours of paired energy storage capacity that can be dispatched by the Utility, CCA or CAISO.

[8] TURN recognizes that eligibility for the Low-Income Community Bonus Credit and Solar for All funding is limited to projects with a maximum nameplate capacity of 5 MWac.

• Utilities should be required to identify (and rank in order of grid value) multiple locations on their distribution systems where projects can interconnect with minimal upgrade costs.

• Ratepayer-funded compensation to the project should be based on ReMAT/PURPA pricing plus an adder to reflect the generation capacity value of energy storage. Once operational, project storage may be remotely dispatched to serve local or statewide grid needs.

• External funding should be available to offset a maximum of the entire cost of energy storage installed at the project (without jeopardizing the value of federal tax credits). The amount of requested storage capital subsidy should be included as part of the developer bid.

• Projects should be required at minimum to allocate sufficient revenue to ensure that all low-income residential subscribers receive long-term credits that, in the first year of operation, will produce at least a 20% bill reduction. Non-low income or non-residential subscribers may receive a lower bill reduction.

• Additional one-time external funding could be made available if projects are unable to provide sufficient subscriber credit values under this framework.

• A reverse auction process should be used to select winning projects. Key elements of the process include: 1) a single stage auction to reduce the risk of bidding strategies designed to enable price discovery; 2) all utility solicitations have the same or similar format and requirements; and 3) all utility solicitations should be conducted and awarded at the same time.

• Project bids should identify the proposed adder price, the requested external grant funding subsidy for storage; and the required generation capacity adder.

TURN believes a reverse auction structure that includes the foregoing elements could create a foundation for a workable CREP. For purposes of evaluating possible outcomes, TURN used the NREL CREST model to calculate illustrative pricing. TURN assumed a 6.7 MW project (5 MWac) with total project costs of $17.9 million and capital costs for storage of $8.9 million[9], debt financing of 46% at 6.96% for 15 years, equity returns of 11.50%, a contract term of 20 years, and the 30% Investment Tax Credit (ITC). Under these assumptions, the model produces an illustrative levelized price of 15.35 cents/kWh or 9.55 cents/kWh if the costs of the storage are covered by a grant financed with external funds (Solar for All, Legislative appropriation).[10] The nearly 6 cents/kWh difference in pricing demonstrates the positive impact of external funding applied to the cost of storage.

An $8.9 million per project storage subsidy could support roughly 28 new projects of this size (total of 140 MWac) and an equivalent amount of 4-hour storage assuming the entire $250 million of Solar for All Funding is applied to the program.[11] If additional external funding became available in the future, even more new projects could be incentivized.

The lower costs resulting from the storage subsidy could allow projects to share a portion of operating revenues with subscribers to support the 20% bill credit for low-income customers. However, achieving this bill credit for CARE customers would require approximately 6 cents/kWh of project revenues being allocated for this purpose. Assuming that levelized project costs are 9.55 cents/kWh (with the storage subsidy), total project revenues would need to be approximately 15.55 cents/kWh to allow for 6 cents/kWh to be used for subscriber bill credits.

[9] TURN uses NREL values for balance of plant and other costs and operating assumptions and an indicative cost of $444 per kW for storage. Calculation: 5000 kW x $444 x 4 hrs.= $8.88 million for 5 MW of 4 hr. storage.
[10] TURN has assumed that the state grant is not treated as taxable income and that the project qualifies for maximum ITC.
[11] $249 million/8.9 million in subsidy = 28 projects x 5 MWac = 140 MWac

While this approach appears workable, the Commission should recognize that the scale of potential deployment is heavily constrained by available external funding. There is little hope that the CREP can effectively serve a significant portion of Title 24 alternative compliance needs with the external funding currently available to the Commission. More funding and/or another compensation structure would be needed to allow CREP to achieve any meaningful scale.

II. ANSWERS TO SELECTED QUESTIONS

A. Question 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)?

The Commission should design the CREP to provide sustainable subscriber bill credits without the need to obtain future external funding sources that are not available at the time the project first reaches commercial operation. Given that federal funding under the Solar For All program represents a unique one-time opportunity, the Commission should not assume the future availability of new federal or state funds to support this program. The long-term subscriber guarantee is critically important to the viability of the overall program. There are two basic options for providing a long-term guarantee.

First, the Commission can apply the external non-ratepayer funding to offset some initial investment costs faced by the project developer. Under this approach, funds would be awarded to the developer upon commercial operation so long as the project is committed to long-term participation in the CREP. Providing an up-front lump sum would allow the developer to accept a far lower price for generation and capacity and permit a greater share of ongoing ratepayer-funded compensation to be used for subscriber bill credits. TURN's reverse auction straw proposal would allocate external funding specifically to offset the cost of paired energy storage at the facility with an opportunity to seek additional external funding if necessary to achieve project financing needs and a 20% bill credit for subscribers.

Second, the Commission can require that external funds be used to provide ongoing subscriber credits and direct that 20 years of funding be sequestered at the outset. The sequestering of funds would allow long-term bill credits to be honored. Assuming that subscribers receive approximately $0.06/kWh in bill credits (which currently approximates a 20% bill reduction for CARE customers) over 20 years, the Commission would need to identify and sequester approximately $250 million to support 100 MW of project development.[12] This approach assumes that developers can finance and operate projects based on the available ratepayer-funded compensation (which does not appear to be true). As TURN previously noted, exclusive reliance on developer compensation under PURPA Standard Offer contracts or ReMAT appears unlikely to support financeable projects.

For CREP to generate successful projects, TURN recommends that the Commission select the first option and make funds available to developers in exchange for binding commitments to operate the projects under CREP and accept a lower price for operations pursuant to the reverse auction approach identified in Section I(D). This approach should provide the greatest and most sustained monetary benefits since the funds would be used to offset both debt and equity in the developer's capital structure. Funds should be provided in a manner that allows the developer to realize the full Investment Tax Credit (ITC) value for the gross cost of the facility before receiving any lump-sum subsidy. The Commission must evaluate what mechanisms would best achieve this result including characterizing the lump-sum as a form of prepayment.

[12] TURN assumes a 100 MW solar project operating at a 25% capacity factor with 4 hours of energy storage.

B. Question 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.

TURN is concerned that the "minimum 20 percent revenue share" referenced in D.24-05-065 would result in very small subscriber bill credits that are inadequate to meet federal funding requirements or even to motivate customer participation. While TURN supported a 20% revenue share under the NVBT, that proposal assumed far higher project revenues than would occur under CREP. Applying the 20% share to the ACC values for a solar project with paired energy storage would result in a net credit of approximately 4 cents/kWh.[13] Applying the 20% share to ReMAT or PURPA pricing would yield a net credit of 1.5 - 1.8 cents/kWh.[14]

According to the US Environmental Protection Agency (US EPA), all states receiving funding under the Solar for All program "have committed to delivering at least 20% household savings to all households who will benefit from their programs."[15] Average CARE rates at the beginning of 2024 were 21.5 cents/kWh for SCE, 27.2 cents/kWh for SDG&E, and 30 cents/kWh for PG&E.[16] Providing a 20% bill discount to CARE customers requires first-year credits ranging from 4.3 cents/kWh (for SCE) to 6 cents/kWh (for PG&E). Maintaining a 20% bill reduction over time would require higher credits that track retail rate escalation. The Commission should therefore re-evaluate the 20% "revenue share" referenced in D.24-05-065 since that approach

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[13] This calculation assumes an average ACC value of ~20 cents/kWh for a solar project with 4-hours of energy storage.
[14] This calculation assumes an average ReMAT value of 7.6 cents/kWh and an average PURPA Standard Offer contract value of 8.9 cents/kWh.
[15] https://www.epa.gov/greenhouse-gas-reduction-fund/solar-all-solar-household-savings-highlights
[16] Average CARE rates as of January 1, 2024. Data provided to TURN by each IOU.

appears to fall below the minimum bill savings required by the US EPA for any program receiving Solar for All funding.

Providing a bill credit of 1.5 cents/kWh for non-CARE customers would yield relatively modest overall savings. Average non-CARE rates at the beginning of 2024 were 34.2 cents/kWh for SCE, 40.6 cents/kWh for SDG&E, and 46.6 cents/kWh for PG&E.[17] Applying a 1.5 cent/kWh bill credit would reduce average bills for non-CARE subscribers by approximately 3.2 - 4.4% in the first year (with declining percentage bill impacts over time as rates increase). This outcome falls well below the Solar for All requirement for a 20% bill reduction and would represent an underwhelming benefit that may not induce meaningful participation.

Consistent with the Solar for All requirements, TURN recommends that the Commission assume that CREP participants will realize 20% average bill reductions. At a minimum, the 20% bill reduction should be assumed for CARE and FERA customers (consistent with the savings provided under DAC-GT). If the Commission determines that US EPA will not require 20% savings for non-CARE customers, their bill savings could be set at a lower level (10-15%) to reflect the higher cost of providing discounts to non-CARE customers while still ensuring that participants are motivated to enroll and remain in the program over time.

C. Question 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 billing presentment.

[17] Average non-CARE rates as of January 1, 2024. Data provided to TURN by each IOU.

TURN addresses some of these issues in response to Question 2. TURN does not have a specific proposal for the method of presenting the credit on the customer bill other than to require that the discount be shown as a separate line-item that identifies the sources of funding used to provide the benefit.

D. Question 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.*

TURN recommends that the incentive be based on a dollars per watt for storage capacity and designed to offset no more than 100% of the incremental costs of paired storage. As noted in response to Question 1, the Commission should consider structuring the developer incentive as prepayment for the value of energy and capacity if this approach would allow the developer to receive the full ITC value for the gross cost of the facility. Any incentive should be designed to maximize the total value of federal tax credits and ideally should not be treated as income to the developers so there is no need for a gross-up to provide the full storage cost offset.

TURN does not see a particular reason to adjust the incentive based on the proportion of low-income customers that subscribe. However, TURN does support increased incentives for projects that satisfy the Community Benefit Partner (CBP) project criteria outlined in TURN's testimony and briefs.[18] Specifically, CBP projects would be structured as a partnership between developers and community entities (such as local governments) with optional ownership by the community partners. These projects could be located on land or buildings owned by a local government and may benefit from low-cost financing provided by local entities. CBP projects could further incorporate unique features that have community value such as resiliency centers during power outages (when the facility can remain energized), discount electric

[18] Ex. TURN-1, pages 39-48; TURN opening brief, page 25; TURN reply brief, pages 28-29.

vehicle charging services, or subscriptions for schools or government buildings. Finally, if the external grants are received by the municipal or community partner and donated to the partnership as equity, it is more likely that the grant would not be considered taxable income and smaller grants could be provided with the same level of cost reduction to the project. Because they can provide superior economics and enhanced customer benefits, CPB projects should receive preference for incentives financed with external state and federal funds.

E. Question 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?*

There are two relevant ITC enhancements that should be considered by the Commission in its development of the CREP. The first enhancement is the Low-Income Community Bonus Credit for projects located in low-income communities. Eligibility for this category provides a 10% bonus (resulting in a total 40% ITC) but there are limits on the quantity of resources that can qualify in 2024 and most of the megawatt allocation to this category is reserved for behind the meter installations. The second enhancement is the Low-Income Economic Benefit Project credit for projects that provide at least 50 percent of the financial benefits of the electricity produced by the facility to qualifying low-income households. A maximum of 900 MW will qualify for this credit in 2024. Starting in 2025, the legacy ITC framework will be replaced with a Clean Electricity Investment Tax Credit that retains low-income enhancements for projects located in an eligible community or serving low-income customers.

The Commission should give preferences to projects that qualify for either of the enhanced ITC options. This preference includes priority for incentives paid with external funds, accelerated processing for contracts, and interconnection priority. In exchange, the projects should agree to provide a higher share of revenue with subscribers or accept lower incentives. To effectuate this outcome, the Commission should develop a set of standard assumptions that govern the relationship between ITC levels, external incentives paid, the revenue share provided to subscribers, and total expected bill reductions for subscribers. TURN recommends that the Energy Division produce a straw proposal that could be circulated for comment by all parties.

It is not clear that using the enhanced ITC to justify a lower Power Purchase Agreement (PPA) price would serve the goals of the program. A lower PPA price could result in a smaller "revenue share" credited to subscribers if that share is denominated as a percentage of project revenues under the PPA. Also, any decision to rely exclusively on external funds to provide subscriber benefits justifies using enhanced ITC to minimize reliance on limited external funds and allow greater levels of participation.

The Commission should establish the means of ensuring that developers are motivated to seek the enhanced ITC, using ITC funds to reduce the requirements for external funding sources, and maximizing the number of enhanced ITC projects that participate in the program.

F. Question 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 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?

To the extent that the Utilities are assigned the task of holding federal or state funds used to support the program, TURN recommends that the Commission require these funds be segregated or treat these funds as offsets to working cash. This treatment would ensure that utilities do not benefit from holding additional cash and that ratepayers receive an appropriate adjustment to overall rates.

G. Question 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).

TURN does not have a specific recommendation for startup costs and program administration but would not oppose these costs being collected in rates from all customers.

H. Question 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 recorddoes not contain the specifics for CCA participation."

CCAs should be directed to indicate, pursuant to §769.3(b)(2)(B), whether they intend to participate in the CREP. CCAs participating in the CREP should be permitted to execute contracts for eligible projects, draw on available external funds, and assign bill credits to CCA subscribers. CCAs also should be permitted to set bill credits that exceed the minimum levels required by the Commission so long as the costs of these credits are funded exclusively by CCA customers.

I. Question 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?

As explained in response to Question 5, TURN recommends that the Energy Division develop and circulate a proposal that would address the relationship between ITC levels, external incentives, the minimum revenue share provided to subscribers, and total expected bill reductions for subscribers. This proposal could be turned into a template that tracks all projects enrolled in the program. Such tracking would ensure that projects provide timely reporting on all relevant tax incentives and need for external funding.

J. Question 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.

Although TURN supports the use of auto-enrollment as appropriate, it is not clear how such a process would work for the CREP. Unlike DAC-GT, there is no obvious geographic boundary for CREP to determine the scope of low-income customer auto enrollment. Moreover, CREP eligibility should include non-low income customers (both residential and non-residential) and new home construction. These customers will generally need to affirmatively opt into CREP. The Commission should explore the feasibility of new home community auto enrollment by housing developers.

TURN previously urged the Commission to authorize a statewide third-party administrator to manage enrollment and provide customer-facing information about the program. TURN still supports this recommendation because it would provide a uniform engagement and education experience for customers of different Load Serving Entities. Moreover, there are likely efficiencies with using a single entity for this task rather than spreading it across multiple utilities and CCAs.

K. Question 17

Describe how additional renewable procurement should be accomplished, citing key dependencies to an approved Integrated Resource Plan Decision and process.
a. How would a participant be assured that these resources are from incremental renewable resources?
b. How would program administrators ensure that the renewable energy purchased for modified Green Tariff customers does not result in duplicative procurement?
c. If an approved Integrated Resource Plan or decision does not exist, what would be the correct procedural mechanism for making this determination?

The Commission should require each Utility to demonstrate that procurement to satisfy Green Access Program subscribers is additional to the quantities that would otherwise occur under both the Renewable Portfolio Standard (RPS) program and the Integrated Resource Planning (IRP) process. This requirement can be implemented by directing each Utility and CCA to submit a base portfolio for purposes of IRP compliance that will satisfy reliability, environmental and resource diversity objectives assigned to each Load Serving Entity. The base portfolio shall not include any resources used to serve Green Tariff customers. The Commission should determine IRP compliance based solely upon the adequacy of the base portfolio.

Prior to the next IRP submissions expected to occur in October 2025, any Utility that executes new Green Tariff resource commitments shall not be permitted to count these resources towards any compliance obligation. None of these resources shall be used to meet any assigned IRP mid-term reliability requirements or to satisfy any other procurement orders issued by the Commission. The IRP submissions filed in 2025 should expressly identify resources that may be procured to serve Green Tariff purposes and ensure that they are not used to meet any compliance obligation or GHG target applicable to the base portfolio.

Resources procured for Green Tariff customers shall be separately reported to both the Commission and to the Energy Commission for purposes of the Power Source Disclosure Program. For purposes of RPS compliance, each Utility should be directed to exclude all procurement from these resources from being credited towards compliance obligations and retire the associated Renewable Energy Credits on behalf of subscribers.

III. CONCLUSION

TURN appreciates the opportunity to submit comments on the questions posed in the Ruling.

Respectfully submitted,

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