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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision D. 16-01-044, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 20-08-020 (Filed August 27, 2020)

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR ON ADMINISTRATIVE LAW JUDGE'S RULING SETTING ASIDE SUBMISSION OF THE RECORD TO TAKE COMMENT ON A LIMITED BASIS

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SUMMARY OF RECOMMENDATIONS

The Solar Energy Industries Association and Vote Solar provide the following Summary of Recommendations with respect to their *Comments on the Administrative Law Judge's Ruling to Setting aside Submission of the Record to Take Comments on the Record.*

1. The Commission should adopt the proposed glide path for transitioning from the current net energy metering ("NEM") construct to the successor tariff set forth in SEIA and Vote Solar Opening Comments on the December 13, 2021, Proposed Decision ("PD"). Specifically, the Commission should adopt a glide path which would start with an export compensation rate steeply discounted from the applicable retail rates for Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE"), but then would be divorced from rates and lowered by 20% for each new 1 GW tranche of successor tariff customers, until an export rate based on the ACC was reached.

2. If the Commission determines not to adopt the SEIA / Vote Solar proposed glide path, then the Commission should find that ACC Plus mechanism is superior to a Market Transaction Credit ("MTC") for the general market successor tariff.

3. The Commission should determine that the ACC Plus mechanism will be devised based upon the following key elements:

- Use of realistic solar costs linked to actual costs, such as the $3.52 per watt-DC in 2023 presented on the record by the California Solar & Storage Association ("CalSSA").
- Provision for at least a 10-year simple payback for solar + storage customers and 10% first-year savings for customers who finance their systems. To reach these metrics for sustainable growth, there cannot be either a Grid Participation Charge ("GPC") as contemplated in the PD or a significant non-bypassable charge ("NBC") on BTM consumption.
- Use of the same $ per kWh ACC Adder for both solar and solar + storage residential customers.
- Design of the export rates which consolidates the hourly ACC values using simple averages of hourly ACC values across the same TOU periods used for retail electrification rates
- Use of the E3 model released in December 2021, with the CalSSA solar costs and ACC values averaged by TOU period, results in SEIA's and Vote Solar's recommended residential ACC Plus Adders for the three utilities that are shown in **Table 1**.

Table 1: *Recommended First-year ACC Plus Residential Adders*

Utility/Rate	Solar Cost ($/Watt-dc)	Type of System	Simple Payback (years) or Monthly Savings (%)	ACC Plus Adder $/kWh
PG&E EV2	3.52	S + S	10%	0.106
SCE TOU-D-PRIME		S + S	10%	0.132
SDG&E EV-TOU-5		S + S	10%	0.020

- Provide for the ACC Plus Adder to remain in place for a particular solar customer for a 10-year period beginning when the customer's system comes online.
- Allow for a solar customer to fix the values in the current ACC long term forecast at the time they apply for interconnection, for 15 years for residential customers and 20 years for non-residential.
- Stepdown the residential ACC Adder to zero in five 20% steps, with each step lasting for each utility's share of a 780 MW tranche of new successor tariff residential customers.
- Adoption of the $ per kWh ACC Plus Adders and associated glidepath for non-residential, commercial and industrial ("C&I") customers, as proposed by CalSSA.

4. The Commission should determine that, for low-income customers, an ACC Adder will not be sufficient to reach a reasonable payback and, therefore, an additional MTC or upfront incentive is necessary

5. The Commission should reject the assessment of NBCs on behind the meter consumption.

6. The Commission should create a new track of this proceeding to explore how the elements of the general market net billing tariff need to be altered, and the extent of the needed changes, to serve as a basis for creating a viable community solar program.

Pursuant to the *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Take Comment on a Limited Basis* issued in the above captioned proceeding on May 9, 2022 ("Ruling"), the Solar Energy Industries Association ("SEIA") and Vote Solar submit the following comments.

I. INTRODUCTION

The Commission's mandate in this proceeding has not changed. In crafting a successor to the current Net Energy Metering ("NEM") tariff, the Commission is statutorily obligated to account for all of the requirements under Public Utilities Code Section 2827, including two key requirements that must be balanced: (1) ensuring that the standard contract or tariff made available to eligible customer generators assures that customer-sited renewable distributed generation ("DG") continues to grow sustainably;[1] and (2) providing that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.[2] Throughout this proceeding, SEIA and Vote Solar have demonstrated that these two requirements for a successor tariff can be reconciled, but such reconciliation cannot occur overnight. Balancing these two obligatory components of the successor tariff requires a measured transition to a point where the industry can continue to grow sustainably, and the cost and non-societal benefits of the successor tariff are approximately equal. The Commission's initial December 2021 Proposed Decision ("PD") recognized the need for a transition between the current NEM construct and the successor tariff, and we support the Ruling's continued effort to structure a transition that reasonably balances the statutory objectives.

In our earlier comments on the PD, SEIA and Vote Solar demonstrated how the successor NEM tariff advanced by the PD would place the future of the solar industry in California in jeopardy, and thereby not fulfill the Commission's statutory obligation that customer-sited renewable distributed generation continues to grow sustainably. Specifically, SEIA and Vote Solar demonstrated that the "glide path" constructed by the PD was, in fact, based on too-low solar costs, included an unreasonable grid participation charge, did not consider that 80% of solar and solar + storage systems are financed, and did not include a self-regulating mechanism to link

[1] Public Utilities Code Section 2827.1(b)(1).

[2] Public Utilities Code Section 2827.1(b)(4).

stepdowns in the glide path to continued growth in renewable distributed generation.[3] SEIA and Vote Solar appreciate that the Commission appears to have recognized these deficiencies in the PD and has reopened the record to solicit additional information to ensure that the successor tariff includes a glide path that adequately balances the conflicting statutory goals. We put forth a proposal in their opening comments on the PD, based on the record of the proceeding, that was aimed at providing such a balance. Specifically, we proposed a glide path which would start with an export compensation rate steeply discounted from the applicable retail rates for Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE"), but then would be divorced from rates and lowered by 20% for each new 1 GW tranche of successor tariff customers, until an export rate based on the ACC was reached.[4] While this offer differed from the proposal we presented earlier in the proceeding and included a much steeper glide path for the industry, it would sustain the industry during the necessary transition period.

That said, SEIA and Vote Solar have carefully considered and analyzed the alternative ACC Plus proposal set forth in the Ruling. As will be discussed in full below, for general market customers we agree that an ACC adder, if structured correctly over a sufficient period of time, could provide a reasonable transition for the industry. The ACC Plus construct, however, would need to be designed with accurate data and have the following key elements:

- Based on realistic solar costs linked to actual costs, such as the $3.52 per watt-DC in 2023 presented on the record by the California Solar & Storage Association ("CalSSA").
- Provide for at least a 10-year simple payback for solar + storage customers and 10% first-year savings for customers who finance their systems. To reach these metrics for sustainable growth, there cannot be either a Grid Participation Charge ("GPC") as contemplated on the PD or a significant non-bypassable charge ("NBC") on BTM consumption, as discussed in Section III below.
- Use the same $ per kWh ACC Adder for both solar and solar + storage customers.
- Stepdown the ACC Adder to zero in five 20% steps, with each step lasting for each utility's share of a 780 GW tranche of new successor residential tariff customers.
- In designing the export rates, consolidate the hourly ACC values using simple averages

[3] Opening Comments of the Solar Energy Industries Association and Vote Solar on the Proposed Decision Revising the Net Metering Tariff and Subtariffs, R. 20-08-020 (January 7, 2022) ("SEIA/Vote Solar Opening Comments on PD"), pp. 10-13.

[4] *See Id*., pp. 13-14.

of hourly ACC values across the same TOU periods used for retail electrification rates.

- Allow a solar customer to fix the values in the current ACC long term forecast at the time they apply for interconnection, for 15 years for residential customers and 20 years for non-residential.
- Adopt a $ per kWh ACC Adder and associated glidepath for non-residential, commercial and industrial ("C&I") customers, as proposed by CalSSA.

The Ruling, through the ACC Plus concept, offers a potential solution to an effective industry transition. At the same time, however, the Ruling takes a step backward with the concept of assessing NBCs on the behind-the-meter ("BTM") consumption of NEM customers. Fundamentally, the Commission's jurisdictional reach BTM is limited and does not give it authority to assess NBCs on self-consumption. Moreover, there is no cost causation link between BTM consumption and the costs underlying many of the NBCs, rendering the assessment of these NBCs on BTM consumption unjust and unreasonable. There is also the further complication of how to measure or estimate accurately the BTM end-use of solar customers. Finally, there is the practical matter that any levy on BTM consumption result in a higher necessary ACC adder in order to achieve the payback or savings needed to ensure sustainable growth. In other words, the Commission would be requiring NEM 3 customers to pay NBCs on BTM usage only to give the amount they paid back through the ACC Adder.

Finally, SEIA and Vote Solar welcome the Commission's efforts to explore community solar as one means to expand affordable solar offerings to low-income customers. A net billing construct for a community solar program could be successful provided that the parameters of the program are structured in a manner that does not create artificial barriers to its success. It is impossible to determine, however, whether the "low-income customers and/or renters [would] benefit from a community solar tariff program modeled on the Tariff structure" until that structure is adopted. Thus, SEIA and Vote Solar recommend that the Commission should establish the specific elements of the general market net billing tariff and then hold workshops to determine the modifications needed to best create a viable community solar program to serve low-income customers and renters.

II. GLIDE PATH APPROACH

A. ACC Plus is Preferable to the Market Transition Credit (Question 1)

For general market customers, the ACC Plus is a better and more effective approach to achieve a reasoned transition to a successor tariff than the Market Transition Credit ("MTC") advanced in the PD. The objectives of a transition period are twofold. First, it is intended as a step down from the current NEM construct (where the export compensation is grounded in retail rates) to a new structure where the export rates would be based on avoided costs from the Avoided Cost Calculator ("ACC"). The record shows that immediately pricing export compensation at the ACC will place solar and solar + storage out of reach for most customers. Second, the transition period is intended to afford the industry sufficient time to move from solar-only to solar + storage as the industry's primary product. The ACC Plus is a better mechanism to achieve these objectives than the MTC.

The transition in export rates should be based either on the current structure for exports (retail rates) or on the final structure (the ACC). Our comments on the original PD proposed to start the transition from a discount to retail rates. ACC Plus would structure the transition using a declining adder to the ACC. Both mechanisms can provide a reasonable transition based on a glide path in export rates, assuming reasonable values are used to calculate that path. In contrast, the MTC is completely divorced from the customer's exports to the grid. The MTC is a monthly credit of a fixed dollar amount based on the size of the solar system. The MTC is in no way tied to how much the customer exports, to when exports occur, or even to whether the customer's system is operating. The structural similarity between the ACC Plus and the current NEM construct would facilitate customer understanding of the new tariff and avoid having to introduce and explain an entirely new billing component. Customer understanding and acceptance are critical to the industry's ability to market their products.

Moreover, the ACC Plus, by providing a $ per kWh adder to the export rate, offers more support for the solar-only customer during the glide path to export rates based on the ACC. This support is critical over the next few years. While SEIA and Vote Solar recognize that the end game is to transition the industry to one whose primary product is solar + storage, the industry simply is not there yet. The record demonstrates the significant barriers which are still facing the industry with respect to this goal.[5] Support for the solar-only market over the next few years, using a glide path in ACC Plus export rates, is critical to allow the industry sufficient time to overcome these barriers and complete the transition to solar + storage.

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[5] SEIA /Vote Solar Opening Comments on PD, pp. 12 -13 (documenting the record evidence regarding these barriers, e.g., current lack of cost effectiveness, supply chain issues for the batteries, need to finalize installation codes and standards).

Finally, SEIA and Vote Solar emphasize that there is a role for an MTC – or, even better, upfront buydown incentives – in the compensation structure for low-income customers, including CARE and FERA customers. CARE customers need additional support because their rates are 32.5% to 35% lower than the non-discounted rate, while FERA customers receive an 18% discount. These rate discounts result in reduced savings from the use of solar BTM. .Low-income solar is more costly to install, as program costs from the DAC-SASH program show., In addition, the Commission must recognize that compensation through export rates is effectively capped for each annual billing period by the residential minimum bill or the non-bypassable charges that solar customers must pay. The result can be that, even when export rates are increased as much as possible, low-income customers do not reach a reasonable payback. In such circumstances, there is a need for a low-income MTC or an upfront buydown incentive to provide the necessary support for DER adoption among low-income customers. This is discussed at greater length in the comments of Vote Solar – GRID Alternatives – Sierra Club.

B. Ensuring that Distributed Generation Continues to Grow Sustainably is Better Served by a Stepdown of the Retail Rate (Question 2)

SEIA and Vote Solar continue to believe that a glide path approach that sets export compensation rates at a declining percentage of the retail per-kWh rates is a more effective approach to ensure that customer sited renewable distributed generation continues to grow sustainably, compared to either the ACC Plus or an MTC. Nonetheless, as stated above, a reasonably constructed ACC Plus structure may be acceptable.

The fact is that whatever shape the NEM 3.0 successor tariff ultimately takes, it will be substantially different from the net metering structure which has been in place for the last 20+ years. The willingness of customers to invest in solar or solar + storage is ultimately tied to their ability to understand and accept the basis upon which they will be compensated. In this regard, we submit that an export rate linked to the retail rate is superior to ACC Plus, because retaining a link between the retail rate and export compensation will enhance customer understanding and thus the sustainability of the market.[6]

Further, the industry has long experience and confidence in net metering structures based on retail rates, and the certainty and familiarity with retail rates has been critical in financing solar systems. Four-fifths (80%) of distributed solar and storage systems are financed through

[6] Exh. SVS-04 (Beach), p. 41, lines 3-9.

loans or power purchase agreements.[7]That is why the glide path proposed by SEIA and Vote Solar in our comments on the PD would start with an export compensation rate steeply discounted from each utility's applicable retail. We then proposed to reduce the export rate by 20% for each new 1 GW tranche of successor tariff customers.[8] Such a structure allows for reasonable certainty in the customer's export compensation over the life of the system, and thus the customer's ability to repay the loan. While an ACC Plus approach to the glide path can provide a level of certainty based on the published ACC values in the currently effective ACC, there will be less certainty for the customer than a structure based on retail rates.

The ACC is revised every two years, and thus there is far less certainty and familiarity in what the level of the ACC will be in the future. To date, the track record of the ACC does not inspire confidence. There was a substantial and largely unexplained reduction of over 70% in solar-weighted ACC values from the 2020 ACC to the 2021 ACC.[9] The ACC is based on complex modeling using a resource planning model and a production cost model. Modeling changes appear to have caused the drop in solar-weighted ACC values from 2020 to 2021, without any changes to the underlying resource economics that would justify such a large decrease.[10] Retail rates are not subject to such volatility, and customers, the financial community, and the solar industry have experience with typical year-to-year rate changes. That is why a glide path based on retail rates would be preferable to the ACC Plus concept. That is also why SEIA and Vote Solar continue to recommend that, if the ACC is used as the basis for export rates, customers should be able to lock in the current ACC values for periods of 15 years for residential and 20 years for non-residential commercial systems. This is essential to allow

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7 *Id*., at p. 48, lines 10-14: "Lawrence Berkeley National Lab's (LBNL) annual *Tracking the Sun* reports show that 37% of systems installed in 2019 were third-party-owned; this percentage approached 60% in 2012, but has dropped as solar loans have replaced PPAs. Two-thirds of host-owned systems are financed. This means that, overall, almost 80% of residential solar systems are financed."

8 *See* SEIA/Vote Solar Opening Comments on PD, pp. 13-14.

9 See Figure 4 from the Documentation for the draft 2021 ACC, showing the single-year change in the value of selected DERs in 2030. The value of solar PV drops by 74%, from 11.7 cents per kWh to 3.1 cents per kWh.

10 See Resolution E-5150, at p. 37: "[The 2021 ACC] corrects a number of errors made in the 2020 ACC that we were made aware of during the last year." No specification of these errors is presented in the Commission's discussion in this resolution, nor did the Commission provide a clear explanation of why their correction produced such a large change in the 2021 ACC values compared to the 202 ACC.

potential DER customers to assess the value proposition of their investment and to ensure lenders will finance such investments.[11]

The final option, setting export rates at the ACC immediately, then using a fixed monthly MTC to achieve a reasonable payback or monthly savings for the solar customer, introduces the same uncertainty with the use of the ACC as ACC Plus, then adds the additional complexity of a new, unfamiliar compensation component with which the solar industry, the financial community, and customers have no experience.

C. Stepdown of Retail Rate versus ACC Plus for Providing Value to Grid (Question 3)

Export rates based on either (1) a percentage of retail electrification rates or (2) the ACC plus an adder will send important price signals to solar and solar + storage customers. There are strengths and weaknesses to each approach. As discussed below, it is difficult to say which approach will provide "higher value to the electric grid."

The residential electrification rates likely to be used in NEM 3.0 have time-of-use ("TOU") rate differences that are based on marginal costs, unlike the "TOU-lite" rate differences in default residential rates. As a result, the rate differentials between TOU periods in retail electrification rates send important and accurate price signals. Of course, retail rates are not set exactly at marginal costs, and generally must be scaled up from marginal costs using an equal percentage of marginal costs ("EPMC") scalar. That said, NEM 3.0 export rates set at a percentage of retail electrification rates thus may be quite close to marginal costs, depending on how the percentage discount compares to the EPMC scalar.

The ACC represents the utilities' long-run avoided costs and uses many of the same marginal costs and hourly allocations employed in retail rates. For example, both retail rates and the ACC use forecasts of CAISO energy market prices to set marginal/avoided energy costs. Both also use storage costs to set marginal/avoided generation capacity costs. The long-run avoided transmission and distribution ("T&D") costs used in the ACC are the same marginal T&D costs used in retail rates. However, a significant problem with the use of the ACC to set export rates directly is the false precision of the hourly ACC values.

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[11] *Id.*, at pp. 16-17. The longer lock-in for commercial systems is necessary given the lower rates and reduced bill savings for these systems. The locked-in ACC values should be those that are current when the new solar customer applies to interconnect.

Specifically, the ACC uses a loss-of-load expectation ("LOLE") analysis that assigns much of the annual avoided generation capacity value to the month of September. As a result, the ACC values in September – especially in the first week – are very high. See the figure in **Attachment A**, which compares the following hourly profiles of ACC values for PG&E in 2023: (1) the first week in September, (2) the month of September, (3) the four summer months (June-September), and (4) aggregated by the summer EV2 TOU periods. The hourly ACC values for the first week in September might be accurate during a summer heat wave, but the problem is that such heat waves do not always occur just in the first week in September. For example, the 2020 heat wave that caused blackouts in California occurred in mid-August. The annual peak hourly retail loads on the CAISO system have occurred as early as June 20 (in 2008) and as late as September 15 (in 2014).[12] As a result, the hourly ACC values convey a false precision that will distort price signals to customers – only by chance will the first week in September be a heat wave with high prices and thin reserve margins.[13] The ACC-based export rates proposed in the PD – 24 hourly weekday rates and 24 hourly weekend rates each month – have the same issue. If the ACC is used to set export rates under an ACC Plus framework, SEIA and Vote Solar strongly recommend that the hourly ACC values should be consolidated into the same TOU periods as the retail rates that the customer faces.[14] **Attachment A** to these comments includes the resulting ACC values in 2023 when hourly ACC values are averaged across the TOU periods used in the three investor-owned utilities' ("IOU") electrification rates.[15] ACC Plus export rates will convey more consistent and accurate price signals over the course of each season, and be easier for customers to understand and to act on, if they use the same TOU periods that the customer faces in their applicable retail rate.

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12 See http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.

13 Real-time price signals based on actual high-demand, high-risk grid conditions are better conveyed through critical peak pricing programs.

14 SEIA and Vote Solar note that the IOUs also are concerned with this issue and have proposed to aggregate ACC values into two seasonal (summer and winter) sets of 24-hourly ACC values. See the Opening Comments of the Joint IOUs on the PD, at pp. 13-15: "the PD's proposed structure for export compensation is overly complex and may create customer confusion."

15 E3's model provided with the PD includes a flag to convert to export rates consolidated across TOU periods. *See* Cell D124 on the Dashboard for the E3 model. As is done in the E3 model, SEIA and Vote Solar support consolidating ACC values into TOU periods using a simple average across the hours of each TOU period. The use of a simple average across each TOU period recognizes the difficulty in predicting export profiles when solar increasingly is paired with storage.

D. A Fixed Dollar per kWh Adder is Better than a Percentage Adder for the Industry Transition (Question 4)

SEIA and Vote Solar support a fixed $ per kWh adder to the ACC. This is the approach that is the simplest and easiest to understand and to calculate when quantifying the adder needed to reach a certain payback or monthly savings. A percentage adder could result in extremely high ACC export rates in a few hours, unless ACC values are consolidated into TOU periods as recommended above. Moreover, a fixed $ per kWh adder will provide additional support for solar-only systems during the first years of the glide path, compared to the percentage adder. As discussed in response to Question 5, this support will diminish rapidly as the adder is reduced during the later years of the glide path.

E. The Same Adder Should Apply to Solar and Solar + Storage (Question 5)

We support a single, fixed $ per kWh adder that applies to both solar-only and solar + storage systems. Again, this is the simplest approach. The design focus of this adder should be the customer economics of the solar + storage systems that is intended to become the standard for the industry by the end of the glide path. A single fixed $ per kWh adder also avoids the issue of distinguishing between solar-only and solar + storage systems in the IOUs' interconnection portals. As the ACC adder decreases over the years of the glide path, the benefit of the adder for solar-only systems will decline faster than for solar + storage, reducing the attractiveness of solar-only compared to solar paired with storage.[16] This will send clear signals to customers to choose solar + storage systems and to the industry to make solar + storage its primary product.

F. Impact of ACC Plus on Solar Dispatch (Question 6)

The question of how residential storage will be dispatched depends, first, on how the hourly ACC values are consolidated into export rates, as discussed above in response to Question 3. If hourly ACC values are only consolidated into 48 hourly values each month (24 for weekdays / 24 for weekends), as provided in the PD, the result will be to signal to customers to use storage to maximize consumption BTM for most of the year, because only in September will export rates be high enough to strongly encourage exports in the 4 p.m. to 9 p.m. summer on-

[16] All else equal, the reduction in the adder over the glide path will increase solar-only paybacks by 45% to 70%, while solar + storage paybacks will increase by only 20% to 25%. Thus, this structure will strongly encourage the adoption over time of solar paired with storage.

peak period when exports are most beneficial to the system as a whole. If ACC values are averaged across the same TOU periods as the retail electrification rates, as we have proposed, the result will be a stronger signal to export in the on-peak hours of all of the summer months. This signal will be enhanced under ACC Plus by a fixed adder to ACC values. Thus, the ACC Plus structure, with ACC values averaged across the retail rate TOU periods, will encourage residential customers to export more stored energy during the summer on-peak period, compared to the export rate structure in the PD. This also will be an export rate structure that is much simpler for customers to understand.

On a closely related issue, SEIA and Vote Solar are concerned with the storage dispatch assumptions included in the E3 model released with the PD in December 2021. The E3 model assumes that residential solar + storage customers can dispatch the stored energy not needed to serve their own on-peak load into exactly the one or two on-peak hours with the highest ACC values each day. We are not aware that residential inverters are capable of such precision control of storage dispatch, and it is not now feasible for solar installers or inverter manufacturers to re-program hundreds of thousands of residential storage systems every time the ACC changes. This is another reason why the use of ACC values consolidated by simply averaging across TOU periods makes more sense – it will simplify the price signals that encourage residential customers to dispatch their storage into the on-peak window from 4 p.m. to 9 p.m. ACC values consolidated into TOU periods also should be used to calculate the ACC adders, as we do below, in order to represent fairly the capabilities of current inverters and battery systems.

G. The ACC Adder Should Target a 10 Year Payback or 10% Annual Savings (Question 7[a])

If the Commission adopts ACC Plus, it is essential that the calculation of the ACC Plus adder continue to be premised on achieving the reasonable benchmark of a 10-year simple payback for solar + storage systems and on a realistic cost of residential solar that is grounded in actual residential solar costs in California. The record shows that paybacks of 10 years or less are typical in states that continue to see sustainable growth in their solar markets after significant changes to their NEM tariffs.[17] A 10-year payback will work to sustain California's market, and enable the transition to solar + storage, but only if it is premised on realistic costs for installing these systems. SEIA, Vote Solar, CalSSA and other parties have commented at length on the

[17] See Exh. SVS-03, at pp. 54-55 and Figure 14.

problems with the $2.34 per watt-DC solar cost used in the PD.[18] A reasonable solar cost that is in the record is CalSSA's $3.52 per watt-DC, which is grounded in recorded costs from the Commission's interconnection data base for residential solar systems in the IOU service territories.

Moreover, when determining the adder, the Commission must bear in mind that 80% of solar and solar + storage systems are financed. Reasonable financing terms are critical if access to solar and storage is to be expanded to all Californians, including low- and moderate-income customers. The E3 model published with the PD, and used to calculate paybacks, looked only at providing 10-year simple paybacks. This is a reasonable metric for the minority of systems for which the customer pays cash. However, the Commission also needs to look at the economics of the majority of financed systems, given their importance in expanding access to more customers. We recommend that the Commission adjust the ACC adders based on a 10-year simple payback to ensure that they also produce initial annual bill savings of at least 10% for financed solar + storage systems. In other words, the annual cost of financing the system (interest & principal) should be at least 10% less than the first-year bill savings. The record in the case supports financing terms for typical solar loans of 18 to 20 years and an interest rate of 5%,[19] but the interest rate should be raised to 7% to reflect today's environment of increasing interest rates.[20]

Consistent with the above, and in response to the Ruling's request for recommendations for what the ACC Plus adders should be in Year 1 (assumed to be 2023), SEIA and Vote Solar recommend the fixed $ per kWh ACC Plus adders for PG&E and SCE general market residential customers in 2023 that are shown in the final column of **Table 1** below.[21] These adders are based on:

- Solar costs of $3.52 per kW-DC.
- A 10-year payback for solar + storage systems, increased if necessary to produce 10% first-year savings for solar + storage systems financed with a 20-year loan at 7%. The

[18] SEIA/Vote Solar Opening Comments on PD, pp. 8-9; CalSSA Opening Comments on PD, p. 12.

[19] See Exh. PCF-15 (the NEM 2.0 Lookback Study) at p. 75, citing 18-year terms for solar financing and Exh, SVS-3 (Beach), at p. 15, Table 1) citing 20-year terms.

[20] The interest rates on typical loans obtained by single-family homeowners have increased by over 2% since mid-2021. See https://www.freddiemac.com/pmms.

[21] The Joint Comments of Vote Solar, GRID Alternatives, and Sierra Club filed concurrently recommend higher incentives for low-income customers, as discussed in response to Question 8.

calculations to produce these savings assume no GPC or NBC charge on BTM consumption.

- Consolidating ACC values into the same TOU periods used in the IOUs' electrification rates, as shown in Attachment A.
- An assumption that the ACC Plus adder will remain in place for a particular solar customer for a 10-year period beginning when the customer's system comes online.
- Use of the E3 model released in December 2021, and the use of the existing record for the key drivers of the model – including solar costs and retail rates.

Table 1: *Recommended First-year Residential ACC Plus Adders*

Utility/Rate	**Solar Cost** ($/Watt-dc)	**Type of System**	**Simple Payback** (years) or **Monthly Savings** (%)	**ACC Plus Adder** $/kWh
PG&E EV2	3.52	S + S	10%	0.106
SCE TOU-D-PRIME		S + S	10%	0.132
SDG&E EV-TOU-5		S + S	10%	0.020

For SDG&E, the ACC Plus adder required to reach 10% monthly savings for solar + storage is much lower than for the other two IOUs, due mainly to the use of the EV-TOU-5 rate. If the Commission were to determine, in a subsequent proceeding, to replace EV-TOU-5 with a different electrification rate, the ACC Plus adder for SDG&E should be revised using the same calculations used to produce the ACC Plus adders in Table 1.

H. Length of Residential Glide Path for ACC Plus (Question 7[b])

SEIA and Vote Solar recommend that the first-year ACC Plus adders in Table 1 should step down by 20% when each IOU reaches its share of a total of 780 MW of new residential NEM 3.0 solar installations across the three IOUs' service territories. We recommend that stepdowns occur individually for each IOU, when the IOU reaches its share of a 780 MW tranche of capacity. This is the same capacity-based structure and process for stepdowns in export rates for general market residential customers that SEIA and Vote Solar recommended in our testimony.[22] This will complete the transition in five steps and approximately five years, assuming a similar pace of deployment to what the market has experienced over the last five

22 See Exh. SVS-03, at p. 45 (Table 6).

years. We note that each 20% stepdown in the ACC adder corresponds to approximately a 2% to 4% decrease in residential solar and storage costs. Clearly, it will be challenging for the industry to reduce costs at this pace – particularly given the current headwinds – for all segments of the market – of supply chain issues, solar import tariffs, the scheduled decline of the investment tax credit, higher inflation, competition with EVs for batteries, pending prevailing wage legislation, and pending new requirements for licensing solar installers. We discuss our recommendations for how to structure an ACC Plus glide path for the non-residential market in Section J below.

I. ACC Plus Will Not be Sufficient for Low Income Customers (Question 8)

SEIA supports the proposal for low-income customers set forth in the joint comments of Vote Solar, GRID Alternatives, and the Sierra Club. Their proposal includes both ACC Plus adders and an upfront buydown incentive for low-income customers. The ACC Plus adders in their proposal differ from the general market adders proposed in Table 1, because low-income solar costs are higher than general market solar costs, and CARE and FERA rates are lower, resulting in reduced savings from the use of solar on-site. In addition, the amount of additional compensation that can be added through an ACC Plus adder on export rates is capped by the residential minimum bill or the non-bypassable charges that solar customers must pay (whichever is larger over the course of a year). Thus, to reach a reasonable payback, low-income customers need the support of an added MTC or buydown incentive even when export rates are increased as much as possible.

J. ACC Plus Should Apply to Nonresidential Customers (Question 9)

ACC Plus also should apply to nonresidential, commercial and industrial ("C&I") customers. The record in this case shows clearly that the C&I market has lagged the residential market in recent years, due to the switch to an evening peak period and C&I rate designs with lower volumetric rates.[23] In our prior comments on the PD, SEIA and Vote Solar recommended a glide path in export rates for non-residential customers, starting at the current retail rate, with a 10% stepdown in the export rate for each 1 GW tranche of solar added until the then-current ACC by TOU period is reached.[24] We can accept moving this glide path to an ACC Plus structure. We have reviewed and support the comments of CalSSA proposing specific ACC Plus

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[23] See Exh. SVS-03, at pp. 56-58.

[24] SEIA/Vote Solar Opening Comments on PD, at p. 14.

adders for specific types of non-residential customers, plus a graduated step-down in these adders. This proposal would afford the industry the time necessary to transition all market segments to solar + storage as the primary product.

SEIA and Vote Solar recommend that the stepdowns in the residential and non-residential markets should move separately. The project development, construction, and interconnection timelines are substantially longer for non-residential solar and storage projects. A given tranche of value for commercial customers should not be prematurely closed based on the faster residential sales cycle. Additionally, the two market segments experience different project economics. One tranche of ACC Plus adders may offer sufficient value for one market segment, while the other one slows down. The stepdowns for the residential and non-residential market segments should not be linked.

III. NON-BYPASSABLE CHARGES ON GROSS CONSUMPTION

A. NBCs Should Not be Assessed on BTM Consumption (Question 10)

The Commission should not assess NBCs on any BTM consumption. The energy produced and consumed BTM does not originate nor travel on the systems of the Commission-regulated investor-owned utilities. The Commission does not have regulatory authority over individual NEM customers as generators. These generators are not electrical corporations (and thus public utilities) over which the Commission has broad sweeping regulatory authority.[25] Indeed, the definition of electrical corporation specifically excludes "independent solar energy producers,"[26] such as NEM customers. Because NEM customers are not public utilities, the Commission's broad reaching jurisdiction under PU Code Section 701[27] does not govern the

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[25] *See* PU Code Section 218(a) ("Electrical corporation" includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others.)

[26] Cal. Pub. Utils. Code § 218(e) defines "independent solar energy producer" as "a corporation or person employing one or more solar energy systems for the generation of electricity for any one or more of the following purposes: (1) its own use of the use of its tenants; or (2) the use of, or sale to, not more r than two other entities or persons per generation system solely for use on the real property on which the electricity is generated, or on real property immediately adjacent thereto."

[27] Under PU Code Section 701, the Legislature grants the Commission the power to "supervise and regulate every public utility in the State" and do all things "necessary and convenient in the exercise of such power and jurisdiction."

jurisdictional analysis. Any authority that the Commission may have to regulate a solar customer must be grounded in a specific statute.[28]

No statute – including PU Code Sections 2827 and 2827.1 addressing the NEM program-expands the scope of the Commission's authority over NEM customers (i.e., eligible customer-generators) to include charging rates for behind-the-meter consumption. While Section 2827.1 provides that the Commission must use a rulemaking to determine "which rates and tariffs are applicable to customer generators"[29] and must "establish terms of service and billing rules for eligible customer-generators,"[30] these provisions are in reference to the regulated service provided by the jurisdictional utility to the NEM customer – not in reference to the BTM generation and consumption of such customers.

NBCs are charges relating to the cost of providing service by jurisdictional electrical corporations which are collected through Commission-approved rates for *service provided by the regulated utility*. Energy which is produced and consumed BTM is not a service provided by the regulated utility. Simply put, the Commission lacks jurisdiction to directly apply charges associated with jurisdictional retail electric service – in this case NBCs – to electricity that is self-produced and self-consumed by NEM generators.

Moreover, even if the Commission's jurisdictional hurdle did not exist, assessing NBCs on BTM consumption would violate PU Code Section 453(a), which prohibits a public utility from unjustly discriminating between customers with respect to rates. Customers who are not on a net metering tariff pay NBCs based on their imports from the grid. Consistent with Section 453, NEM customers should be assessed NBCs in the same manner.[31]

In Decision 16-01-044, the Commission appeared to recognize these limitations on imposing NBCs on NEM customers. In that decision it determined that customers on the NEM 2 tariff should pay certain NBCs (public purpose programs, the DWR bond charge, competition transition charge and the nuclear decommissioning charge) on all imports. This was a change from the then-current practice of only paying such charges on the netted-out quantity of energy

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[28] *See City of Inyo v. Pub. Util. Comm'n.,* 26 Cal. 3d 154, 160 (1980).

[29] PU Code Section 2827.1 (c) (7).

[30] PU Code Section 2827.1 (c)(2).

[31] NEM customer paying NBCs on the netted-out quantity of energy consumed from the grid, rather than all imports was a product of statute and thus not unjustly discriminatory.

consumed from the grid (i.e. imports less exports). The Commission did not consider imposing these four NBCs on BTM consumption. To the contrary, when imposing the four NBCs on all imports, the Commission noted that such would "move the economic contribution of NEM customers toward being more consistent with the contribution of other customers."[32] In other words, requiring NEM customers to pay the four NBCs on all *imports* was consistent with how other customers pay for such NBCs. By establishing a net billing tariff under NEM 3, solar customers will move to paying the full retail rate – including <u>all</u> NBCs – on all imports from the grid. Thus, the Commission will take the final step in moving the economic contribution of NEM customers to NBCs to be completely in line with the contributions of non-NEM customers – both types of customers will pay ***all*** NBCs (not just the four which were the subject of Decision 16-01-044) based on the amount of power delivered by the utility.

A net billing construct for NEM customers, without NBCs assessed on energy produced and consumed BTM, ensures complete equity among customers in the manner in which NBCs are paid and is consistent with the parameters of the Commission's jurisdiction.

B. Applicability of Specific NBCs to BTM Generation (Question 11)

The Commission's lack of jurisdiction over NEM generators, coupled with a clear policy dictate that all customers should pay NBCs (or any rate) in a nondiscriminatory manner, leads to the conclusion that there is no basis to assess any NBCs on BTM generation. Even if, the Commission were to overcome its lack of jurisdiction, the application of such charges on BTM consumption would still fail on legal grounds – the charges would not be just and reasonable. When examined on an individual basis it is evident that there is a lack of cost causation between the costs underlying the NBCs and BTM generation/consumption, leaving, the application of NBCs on such consumption not just and reasonable.

1. Power Charge Indifference Adjustment

The power charge indifference adjustment ("PCIA") was established to allow an IOU to recover the above-market costs of generation resources purchased on behalf of a bundled customer who leaves the IOU's generation service to purchase generation from another provider. The PCIA is calculated based on the difference between the total portfolio costs of the utility's generation resources and the Market Price Benchmark.

32 Decision 16-01-044, p. 86.

As the Commission has acknowledged, the PCIA is grounded in law.[33] The Commission has synthesized this applicable law - PU Code Sections 365.1, 365.2, 366.2, and 366.3 - as requiring the Commission to ensure that bundled service customers do not experience any cost increases as a result of (1) retail customers electing to receive generation services from direct access ("DA") providers, or (2) the implementation of community choice aggregation ("CCA").[34] Interpreting these statutes based on the general principles of statutory construction, the plain language of Section 365.1 addresses the allocation of certain generation costs to customers of community choice aggregators, customers that purchase electricity through a direct transaction with "other providers,"[35] and bundled service customers.[36] NEM customers do not "purchase" electricity from other service providers (i.e., DA or CAA providers) with respect to their BTM production and consumption. Section 366.2[37] and Section 366.3[38] address the Commission's obligation to ensure that there is no cost shift between customers of a community choice aggregator and bundled customers, but they are in no manner applicable to the power that NEM customers produce and consume BTM Finally, Section 365.2 provides that "The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers." Again, other providers is defined in Section 365.1(a)

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33 Decision 19-08-022, p.6.

34 *Id*., p. 6, footnote 6.

35 As defined in section 365.1 (a) "other provider" means any person, corporation, or other entity that is authorized to provide electric service within the service territory of an electrical corporation pursuant to this chapter, and includes an aggregator, broker, or marketer, as defined in Section 331, and an electric service provider, as defined in Section 218.3 – in other words CCAs and direct access providers.

36 See Section 365.1 (c) (2)(A). Note that while Green Tariff Shared Renewables ("GTSR") customers are also subject to the PCIA, this program was established pursuant to SB 43, which dictates that the program be implemented in a manner that ensures nonparticipating ratepayer indifference. D.15-01-051, pp. 20-21; Cal. Pub. Util. Code Section 2831(h). To ensure this statutorily mandated indifference standard, the Commission extended the PCIA to these customers as well. D.15-01-051, pp. 100-104. No statutorily mandated indifference standard exists for NEM customers.

37 The applicable part of Section 336.2 reads "(a)(4) The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."

38 The applicable part of Section 366.3 reads "Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program."

to mean CCA or DA providers. Moreover, the legislative history clearly indicates that it was not applicable to BTM consumption. The Assembly Bill Analysis summarizing the provisions of the bill states that the bill:

> Specifies that costs shifting cannot occur between customers of electrical corporations and community choice aggregators (CCAs) or energy service providers (ESPs) and requires the CPUC to ensure that departing load does not experience a cost increase as a result in an allocation of costs not incurred on behalf of departing load.[39]

In addition to the fact that the statutory framework upon which the PCIA relies does not encompass NEM customers, the fact is that NEM customers have not and should not cause any above-market costs of generation associated with IOU procurement to serve bundled load. The IOUs have been taking BTM generation into account in their bundled procurement plans for many years.[40] The Commission's current integrated resource planning ("IRP") proceeding uses the load serving entities' demand forecast data, including BTM PV demand, to determine the state's preferred system portfolio. The adopted IRP resource plans have consistently shown approximately 1 GW per year of new BTM solar additions.[41] In other words, the BTM demand forecast is built into the IOUs' portfolio planning thereby reducing the level of generation which needs to be procured to meet reliability and GHG emission goals. There are simply no above-market generation costs associated with BTM consumption.

2. New System Generation / Local Generation

The new system generation charge (assessed by PG&E and SCE) and the local generation charge (assessed by SDG&E) collect the net capacity costs of IOU power purchase agreements (PPAs) which the Commission has pre-determined the costs and benefits of which will be allocated to all benefitting customers, including bundled service, Direct Access, and Community Choice Aggregation customers.[42] The costs of these contracts are allocated through

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[39] Assembly Bill Analysis, SB 350 (September 11, 2015), p. 2 https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB350#

[40] See, e, g. Decision 12-12-010, pp. 5-6 (requiring that the assumptions selected for the Base Scenario in Attachment A to the decision to be l be used by the IOUs in their ongoing bundled procurement) id., Attachments A and C showing small PV (BTM) netted from demand)

[41] See, e.g., D.20-03-028, Table 6 and Figure 3, pp. 42-43 (showing the forecasted additions of BTM solar ("Customer Solar") of 1.02 GW per year).

[42] See PG&E Tariff, Electric Preliminary Statement Part FS, New System Generation Balancing Account, Sheet 1, SCE Tariff. Preliminary Statement New System Generation Balancing Account, Sheet

the Commission-adopted "Cost Allocation Mechanism" ("CAM") and collected through the New System Generation ("NSG") or Local Generation NBC. For the most part, the PPAs, the cost of which are allocated through the CAM, are for the purpose of addressing system reliability. Indeed, in adopting the CAM and associated generation NBCs, the Commission relied on P.U. Code Section 380 which directed the establishment of resource adequacy requirements for all load serving entities.[43] Specifically, the Commission stated that Section 380:

> allows the costs an IOU incurs to sustain system reliability and local area reliability to be fully recovered from all customers on whose behalf the costs are incurred. It is consistent with AB 380 for the Commission to adopt the cost-allocation methodology set forth herein so that the IOUs' bundled customers are not alone responsible for the cost of new generation to *retain system reliability*.[44]

Distributed generation systems located in constrained areas of the grid allow the utilities to avoid reliability-related generation costs. A NEM customer should not be required to pay an NSG or local generation surcharge on BTM generation which helps the IOU to avoid additional reliability-related generation costs.

Moreover, in deciding to which customers the NSG NBC would apply, the Commission was clear in its intent – "preservation of bundled customer indifference *and cost recovery from customers on whose behalf resources were procured."*[45] This construct led the Commission to determine that municipal departing load customers ("MDL") and customer generation departing load ("CGDL") would be exempt from the NSG NBC. In doing so the Commission examined the load forecast upon which the IOUs' long term procurement plans were based (the California Energy Commission Integrated Energy Policy Report forecast) and determined that "future CGDL and MDL are captured by historical trends used to develop the load forecasts." Thus, the Commission concluded:

> The exclusion of MDL and CGDL from the load forecast can only logically be interpreted to mean that the LTPP, which uses that load forecast to determine resource needs in the forecast year, does not include any resources to serve that departing load in that forecast year and beyond. Accordingly, in such

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1; SDG&E Tariff, Preliminary Statement, Balancing Accounts, Local Generation Balancing Account, Sheet 1.

43 Decision 06-07-029, Conclusion of Law 1.

44 *Id.,* Conclusion of Law 2.

45 Decision 08-09-012, p. 14.

circumstances, it would be reasonable to determine that the fair share of departing load for paying the new generation NBCs would be zero. [46]

The same rationale is applicable to the generation which a NEM customer produces and self-consumes. As noted above, this generation is captured in the IOUs' load forecasts upon which their procurement for bundled customers is based. The resources recovered through the generation surcharges were not procured to serve the forecasted amount of NEM generation that was produced and consumed BTM. As the Commission has previously determined with respect to MDL and CGDL, there is no basis for assessing a generation surcharge on this load.

3. Reliability Services

The reliability services NBC recovers the costs of reliability services which the California Independent System Operator ("CAISO") bills to the IOUs as Participating Transmission Operators ("TO"). Reliability Service Costs are defined in the CAISO tariff as "The costs associated with services provided by the CAISO: (1) that are deemed by the CAISO as necessary to maintain reliable electric service in the CAISO Balancing Authority Area; and (2) whose costs are billed by the CAISO to the Participating TO pursuant to the CAISO Tariff. Reliability Services Costs include costs charged by the CAISO to a Participating TO associated with service provided under a Reliability Must-Run Contract, or a Black Start Agreement, as well as Exceptional Dispatches and Minimum Load Costs associated with units committed for local reliability requirements." [47] The reliability services revenue requirement is part of the IOU's FERC authorized transmission revenue requirement. The reliability services charge is not broken out separately as part of the retail customer's bill but is included in the transmission charge.

Requiring NEM customers to pay reliability services charge on self-consumer BTM generation also runs counter to cost causation principles. This energy which has been produced and consumed BTM has never touched the transmission grid. The customer's consumption of that self-generated energy in no manner contributed to the situation on the grid that resulted in the CAISO's need to provide reliability services to the IOUs.

4. DWR Bond Charge / Wildfire Fund

The Wildfire Fund nonbypassable charge was established by the Commission pursuant to

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46 *Id.,* p. 23.

47 *See* Master Definitions Supplement, Appendix A to the currently effective CAISO Tariff.

Public Utilities Code Section 3289(a)(2). This code section provides that "The charge *shall be collected in the same manner* as that for the payments made to reimburse the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code." At the time of enactment of PU Code Section 3289(a)(2), the DWR bond charge was collected from NEM 2 customers on the basis of their imports (netted out within each metered interval). The statutory language requires that Wildfire Fund NBC be collected from NEM customer in the same way that the DWR bond charge was – in other words, only on imports. At no time was the DWR bond charge ever assessed on BTM generation and consumption. The statutory language precludes the Commission from doing so now.

5. PUC Reimbursement Fee

The PUC Reimbursement Fee is set annually by the Commission. The amount of the fee is designed to capture the total amount allocated to the Public Utilities Commission Utilities Reimbursement Account in the state's annual budget. The methodology to determine the fee for each class of utility the Commission regulates - electric, gas, water, and telecommunications – is set forth in PU Code Section 432. Specifically, Section 432(c) provides that:

> Within each class of public utility subject to the fee, the commission shall allocate among the members of the class the amount of its budget to be financed by the fee using the following methods:
>
> (1) For electrical corporations, the ratio that *each corporation's sales in kilowatt hours* bears to the total sales in kilowatt hours for the class (emphasis added).

In other words, the amount of each IOU's PUC Reimbursement Fee NBC is premised on its annual kilowatt hour sales. Generation produced and consumed BTM is not power that the IOU has sold, and thus does not factor into this analysis and assessment. NEM 3 customers will pay the PUC Reimbursement Fee NBC on each kilowatt hour of electricity sold to them by the IOU or by the IOU/CCA, in other words, on all power imported from the grid. There is no basis in law for such a fee to be assessed on generation the IOU does not sell to the NEM customer.

6. Wildfire Hardening

To date, the Wildfire Hardening NBC has been confined to PG&E. The charge repays the costs of the bonds issued by PG&E to obtain funds to cover the cost of Commission-approved capital expenditures aimed at reducing the risk of wildfire through grid hardening and associated programs such as enhanced vegetation management.[48] The production and consumption of generation BTM does not use the transmission or distribution systems, and over time will reduce the amount of transmission and distribution infrastructure which must be constructed, as reflected in the marginal capacity-related transmission and distribution costs used to set retail rates and as a component of the ACC. The fact that NEM customers' BTM production and use of power does not utilize the transmission and distribution systems, coupled with the contribution of their BTM generation and consumption to the IOUs' ability to defer or avoid additional infrastructure projects, supports the conclusion that there is no cost causation nexus between BTM consumption and Wildfire Hardening costs.

7. Competition Transition Charge

The terms and application of the Competition Transition Charge ("CTC") – created to allow the IOUs to recoup the costs of stranded assets resulting from the restructuring of the electric services industry almost 30 years ago – are also governed by statute. P.U. Code Section 369 authorizes this Commission to establish a nonbypassable mechanism to ensure recovery of what are known as "transition costs," while Section 371 provides that the collection of such transition costs will be based on "the amount of electricity purchased by the customer from an electrical corporation or an alternate supplier of electricity," subject to changes in usage occurring in the normal course of business.

Currently NEM customers pay CTC charges on all imports from the IOU. Thus, they are paying the CTC based on the amount of electricity purchased from the IOU consistent with the statute. Electricity produced and consumed BTM is not "purchased" from "an alternate supplier of electricity," i.e., from a DA or CCA provider. Moreover, the statute already accounts for reductions in purchases from the electric corporation, noting that changes can occur in the normal course of business. PU Code Section 371(b) defines changes in the normal course of business to include "installation of demand-side management equipment or facilities, energy conservation efforts, or other similar factors." Demand side management is described in the *California Standard Practice Manual: Economic Analysis of Demand-side Programs* as including conservation (energy efficiency), load management, fuel substitution, load building, and self-generation.[49] Thus the statute governing CTC charges is clear the Commission does not

[48] See Decision 21-06-030, p.4.

[49] *California Standard Practice Manual: Economic Analysis of Demand-side Programs*, p. 2.

have the authority to extend CTC payments to BTM consumption of self -generated energy.

C. Applicability of New NBCs to BTM Generation (Question 12)

If the Commission determines in the future to create additional nonbypassable charges, they should be applicable to NEM 3 customers in the same manner they are to all other customers – on their imports from the grid. To the extent that the Commission stays within this basic framework, which, as stated above, appears to be dictated by the scope of the applicable statutes, then the Commission can apply the new NBC to NEM 3 customers in the same proceeding in which the charge is created. If, however, the Commission attempts to reach BTM, and impose such charge on BTM consumption of self-generated energy, then the Commission would need to establish a separate proceeding to determining the new NBC's applicability to NEM 3 customers. In addition to addressing jurisdictional arguments, the Commission would need to address whether the charge is just and reasonable as applied to BTM generation as well as address any implications for the sustainability of the industry of imposing additional charges on NEM customers.

IV. COMMUNITY SOLAR (Questions 13 and 14)

SEIA and Vote Solar appreciate the Commission's efforts to take another look at the development of a community solar tariff within the confines of the NEM proceeding. The use of community solar as a means to enhance solar access in low-income communities merits further consideration, especially because a majority of low-income households in California are renters and therefore cannot choose to install onsite solar, even if they have the financial means to do so. The low- income program referenced in the Ruling – Community Solar Green Tariff ("CSGT") – is not sufficiently effective. At bottom, the program is too small – 41 MW – to serve the size of the potential market.[50] At present there are no customers enrolled in the program in any of the three IOU service territories.[51] The program has several constraints – including program size, siting requirements, and sponsorship requirements - which make it difficult to put together viable

[50] *See* Exhibit CCS-01, pp. 9-10.

[51] See Quarterly Disadvantaged Communities Green Tariff and Community Solar Tariff Programs Report on Pacific Gas & Electric Company for the Period of January 1, 2022 – March 31, 2022, R, 1407-002 (Apri1 2029, 2022), Attachment, p. 2, Table 1; Quarterly Disadvantaged Community Solar Green Tariff Program Progress Report of San Diego Gas &Electric Company, Q1 2022, R. 14-7-002 (May 2, 2002), p. 2; Southern California Edison Company's Disadvantaged Communities Green Tariff and Community Solar Green Tariff Third Quarter 2021 Report, p. 2.

projects. This fact was made evident by the suspension of solicitations for the program in both SDG&E's and SCE's service territories.[52] Prior to this suspension, SDG&E had held four biannual Requests for Proposals (RFPs) for CSGT projects in its service territory, all of which were unsuccessful in soliciting any bids.[53] SCE completed three biannual RFPs for CSGT projects, yielding only one successful CSGT offer.[54]

Further, the CSGT program does not drive the deployment and operation of community solar projects in a manner that is most beneficial to the grid. An important consideration for the Commission throughout this proceeding has been to establish a tariff that sends price signals to customers to operate their solar systems and manage their energy usage in a manner that is most beneficial to the grid. Extension of the net billing tariff to community solar presents an opportunity for the Commission to establish a community solar program that similarly incentivizes optimal deployment and operation of community solar projects. For example, the Commission should use this opportunity to consider how to ensure the inclusion of storage with community solar projects, as storage can be dispatched in hours when capacity is needed and GHG emissions are highest.

At bottom, the CSGT program on its own cannot effectively serve the low-income community. Moreover, the CGST program was not designed to drive operation of community solar projects in a manner which benefits the grid. Accordingly, the Commission should consider adopting a new model to coexist alongside CSGT and DAC-GT.

The use of a tariff "modeled" on the tariff adopted for the general population of NEM successor tariff customers *could* be a more viable option for a community solar program in low-income communities, but that is a question of specifics – none of which are known at this time. Comparing the advantages and disadvantages of the two programs – the CSGT tariff and a net billing tariff – is impossible when the details of the latter program are not known. The

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[52] See October 28, Letter of Rachel Peterson, Executive Director of the California Public Utilities Commission to Sidney B. Dietz, granting requested suspension of additional solicitation. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/solar-in-disadvantaged-communities/executive-director-ltr-granting-joint-ious-extension-to-file-an-application-for-review-of-dacgt-and.pdf

[53] *See* Southern California Edison Company and San Diego Gas and Electric Company October 11, 2021, Letter to Rachel Peterson, Executive Director of the California Public Utilities Commission, Requesting Suspension of Solicitations for the CGST Program, p. 2.

[54] *Id.*

Commission should first establish the specific elements of the general market net billing tariff and subsequently hold workshops in a new track of the proceeding to determine how that tariff needs to be altered, and the extent of the needed changes, to serve as a basis for creating a viable community solar program.

V. CONCLUSION

SEIA and Vote Solar appreciate the Commission's willingness to continue its deliberations on how best to craft a successor NEM tariff that meets all the statutory requirements. As discussed above, the ACC Plus construct introduced in the Ruling, if structured correctly over a sufficient period of time – using accurate data, no GPC or NBC charges, and other key identified elements – could provide a reasonable transition for the industry, to ensure that customer-sited renewable distributed generation continues to grow sustainably.

That said, the Commission must refrain from approving the Ruling's suggested assessment of NBCs on BTM consumption. Not only does such raise issues regarding the Commission's jurisdiction and whether the assessment of such charges would be just and reasonable, but, from a practical perspective, would only result in increasing the size of the ACC Plus adder needed for sustainable growth.

Respectfully submitted, this 10th day of June 2022, at San Francisco, California.

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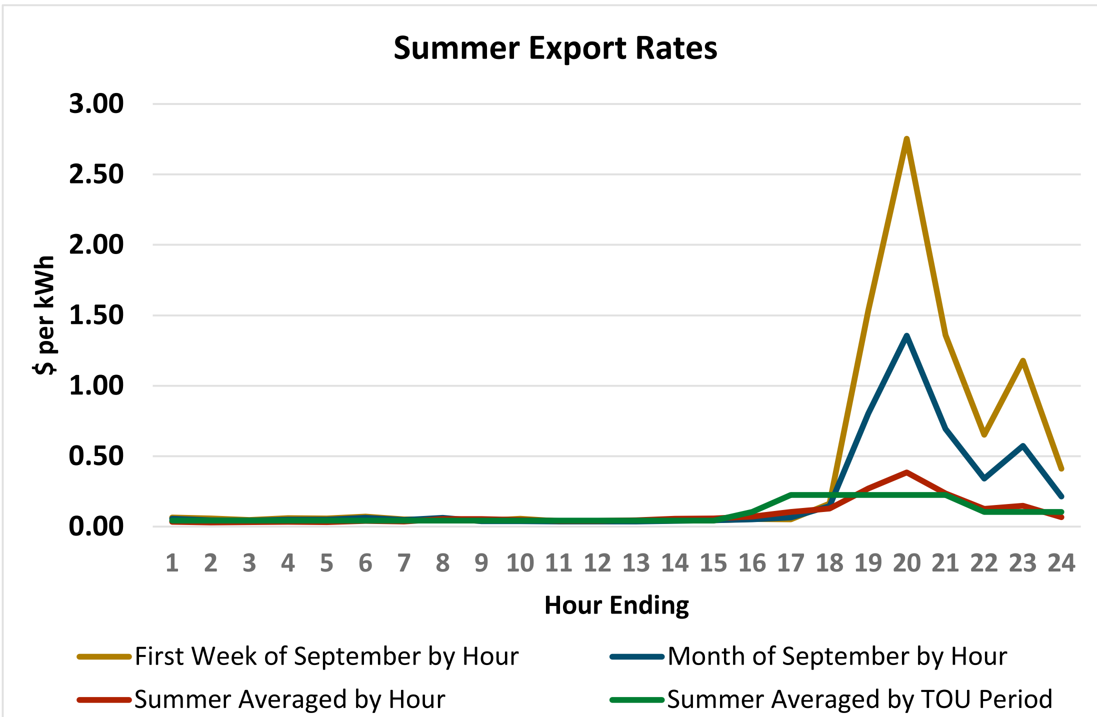
By *<u>/s/ Jeanne B. Armstrong</u>*
Jeanne B. Armstrong

[55] In accord with Rule 1.8, the representative of the Solar Energy Industries Association as the authority to sign this pleading on behalf of Vote Solar.

<u>Attachment A</u>

2023 ACC Export Rates Consolidated by TOU Period

1. Figure comparing hourly average and TOU average 2023 ACC export rates for PG&E in the summer season (June to October).



2. Table showing average export rates by electrification rate TOU period.

Table A-1: *Average 2023 ACC Export Rates by TOU Period ($ per kWh)*

PG&E E-TOU-C		**SCE TOU-D-Prime**		**SDG&E EV-TOU-5**	
Summer Peak	0.2247	Summer On Peak	0.3387	Summer On Peak	0.2135
Summer Part Peak	0.1034	Summer Mid Peak	0.1470	Summer Off Peak	0.0726
Summer Off Peak	0.0424	Summer Off Peak	0.0614	Summer Super Off Peak	0.0309
Winter Peak	0.0837	Winter Mid Peak	0.0916	Winter On Peak	0.0852
Winter Part Peak	0.0445	Winter Off Peak	0.0410	Winter Off Peak	0.0464
Winter Off Peak	0.0327	Winter Super Off Peak	0.0353	Winter Super Off Peak	0.0269