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)

OPENING BRIEF OF THE UTILITY REFORM NETWORK REGARDING A SUCCESSOR TO THE CURRENT NET ENERGY METERING TARIFF

Matthew Freedman, Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org
August 31, 2021

TABLE OF CONTENTS

TABLE OF AUTHORITIES

California Legislation

I. INTRODUCTION

Pursuant to Rule 13.11 of the Commission Rules of Practice and, The Utility Reform Network (TURN) hereby submits this opening brief on the successor to the current net energy metering tariff. This brief provides guidance and a roadmap for the development of a residential Net Energy Metering (NEM) successor tariff that satisfies the requirements of Public Utilities Code §2827.1, the guiding principles adopted in D.21-02-007, and the Commission's obligation to ensure that rates for all customers are just and reasonable.

A. The Commission's failure to adopt meaningful past reforms has created a crisis that must be addressed now

TURN urges the Commission to take this opportunity to make a course correction with respect to NEM policy for residential customers by adopting a revised successor tariff that fairly balances the interests of participants and non-participants. TURN's tariff proposal is designed to achieve this balance while providing the Commission with specific tools that can be used to ensure minimum payback periods, boost participation rates amongst low-income customers and provide additional support to other underserved customer segments. Details and analysis of TURN's tariff proposal, which were included in TURN's voluminous submissions in this proceeding, are summarized in the following sections.

A course correction is badly needed given the current cost shift already borne by non-participants and future retail rate trajectories that threaten the basic affordability of utility service for many customers. The Commission continues to authorize large new grid expenditures by the utilities that, in combination with reductions in residential class retail sales due to NEM-eligible Behind the Meter (BTM) generation, are driving up retail rates at an unsustainable pace. Many of these expenditures are driven by the shared threats of climate change, wildfires and reliability. As more customers flock to

NEM in a rational effort to avoid paying these costs (and rapidly escalating rates), the base of remaining customers left to foot these shared obligations continues to shrink.

Under existing policy, the Commission has offered long-term economic relief to only one group of customers – those with the means and opportunity to install BTM generation. This approach has benefited the few at the expense of the many by shifting costs to the general body of ratepayers for obligations that are not avoided through the deployment BTM resources. Unless the Commission takes bold action now, the existing inequities will accelerate in the coming years with rate increases making basic utility service unaffordable for many customers. In short, the time has come to recognize that the needs of the many outweigh the needs of the few.

The urgency of reform at this juncture is a result of the Commission's failure to make material modifications to legacy NEM policy in the development of the NEM 2.0 tariff adopted in D.16-01-044. In the proceeding that led to the issuance of that decision, TURN repeatedly noted the inequities, inefficiencies and growing challenges of continuing to link compensation for BTM resources to retail rates.[1] Despite approving the final decision on a sharply divided 3-2 vote, Commissioners on both sides recognized that the effort was inadequate. At the Commission business meeting where D.16-01-044 was adopted, Commission President Picker acknowledged that the Decision does not reach any conclusions regarding the valuation of costs and benefits for the successor tariff and explained that these omissions represent "areas where we really fell short".[2] Commissioner Florio noted that the NEM 2.0 successor tariff being adopted was flawed because AB 327 (Perea, 2013) "requires us to look at the costs and benefits and require that they are appropriately balanced."[3] Commissioner Peterman admitted that the Decision creates a "cost shift" that "is a general concern for all of us."[4]

---

[1] Ex. TRN-2, Attachment C (TURN tariff proposal), page 2.
[2] Ex. TRN-2, Attachment C (TURN tariff proposal), page 3.
[3] *Ibid*
[4] *Ibid*

The Commission's failure to act decisively in 2016 effectively locked in decades of excessive and expensive subsidies paid by the general body of ratepayers to benefit a small group of participating customers. The Commission cannot afford to make the same mistake today. Instead, the Commission should embrace a new compensation structure that fairly calibrates adjustments to participating customer bills with the demonstrated incremental value provided by BTM generating and storage resources to all customers and the electrical grid. To the extent that value-based compensation proves insufficient to promote sustainable customer adoption of BTM resources, the Commission should assess the appropriate amount of subsidization required, consider which customers should receive priority access to available subsidies, structure incentives to be efficient and transparent, and explore options for recovering these additional costs from sources other than non-participating customer rates.

B. Issues to be addressed

The November 19, 2020, *Joint Assigned Commissioner Scoping Memo and Administrative Law Judge Ruling Directing Comment on Proposed Guiding Principles* (Scoping Memo) identifies the following issues to be addressed in testimony:[5]

- What information from the Net Energy Metering 2.0 Lookback Study should inform the successor and how should the Commission apply those findings in its consideration?

- What method should the Commission use to analyze the program elements identified in Issue 4 and the resulting proposals, while ensuring the proposals comply with the guiding principles?

- What program elements or specific features should the Commission include in a successor to the current net energy metering tariff?

[5] *Joint Assigned Commissioner Scoping Memo and Administrative Law Judge Ruling Directing Comment on Proposed Guiding Principles*, November 19, 2020, pages 2-3.

- Which of the proposals should the Commission adopt as a successor to the current net energy metering tariff and why? How does each proposal satisfy the adopted guiding principles?[6] What should the timeline be for implementation?

- Other issues that may arise related to current net energy metering tariffs and subtariffs, which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, and the Renewable Energy Self-Generation Bill Credit Transfer program.

As directed by the ALJ at the conclusion of evidentiary hearings, this brief addresses these issues in the same sequence and format that parties were directed to include them in the March 15 tariff proposal and subsequent prepared testimony.

II. SUMMARY OF RECOMMENDATIONS

This opening brief outlines a comprehensive successor tariff proposal, demonstrates how TURN's proposal aligns with guiding principles and regulatory requirements, describes methods for analyzing both TURN's proposal and alternatives, and provides modeled results that show the expected cost effectiveness results. The key findings and recommendations are summarized below.

<u>Relevance of the NEM 2.0 Lookback Study</u>

- The results of the NEM 2.0 Lookback Study demonstrate the massive cost shift associated with both the NEM 1.0 and 2.0 tariffs, the failure of NEM customers to adequately contribute to their cost of service, and the oversubsidization of

[6] During evidentiary hearings, ALJ Hymes specifically directed parties to explain how their preferred tariff proposal satisfies the guiding principles (RT, August 10, page 2199)

participants. These results highlight the importance of major reforms to balance the interests of participants and non-participants.

• The low levels of NEM participation by CARE customers, when compared to non-CARE customers, demonstrates the need for new tariff structures that protect lower-income ratepayers from cost shifting and will result in enhanced participation by CARE customers.

Methods of Analyzing Successor Tariffs

• Application of the Total Resource Cost (TRC) test shows that NEM tariffs are not cost-effective for stand-alone solar deployments and not beneficial to the utility and its ratepayers. Because the TRC test is unaffected by the choice of successor tariffs, it cannot be relied upon to evaluate competing proposals in this proceeding.

• TURN's analysis finds that solar with paired storage provides better cost-effectiveness results (TRC and RIM) than stand-alone solar and should therefore be given priority for purposes of authorizing any ratepayer-funded subsidies.

• The Ratepayer Impact Measure (RIM) test is the only approach that properly accounts for the impact of NEM successor tariff design on all customers. TURN's successor tariff yields RIM scores that are significantly higher than existing NEM 2.0 or the tariff proposals submitted by solar parties.

• The Participant Cost Test (PCT) reflects the value proposition for the participating customer and is a proxy for cost effectiveness from their perspective. Successor Tariffs proposed by the solar parties provide comparable PCT results as the existing NEM 2.0 tariffs. TURN's successor is designed to produce PCT results ranging from 1.11 to 1.19 for CARE customers receiving a Market Transition Credit.

• The Commission should rely on the Participant Cost Test (PCT) and Rate Impact Measure (RIM) tests to evaluate the manner in which different successor tariff proposals balance the interests of participants and all customers.

• The Program Administrator Cost (PAC) test is not useful for evaluating the cost-effectiveness of different successor tariff options.

• The Commission should decline to rely on misleading and unreasonable methods used by various parties to calculate Total Resource Cost (TRC), Rate Impact Measure (RIM) and Participant Cost Test (PCT) values. These unreasonable methods include modeling 20-year successor tariff proposal elements using 25-year values, averaging results across many years, adding participant resiliency benefits to the TRC and RIM results, and limiting the RIM test to exported electricity.

• It is inappropriate to assume "resiliency benefits" realized exclusively by a participating customer with paired solar and storage would benefit non-participants. Moreover, there is insufficient evidence in this proceeding to reach any findings with respect to resiliency values that take into account customer location and any likely benefits to a local community.

• If the Commission desires to consider "societal benefits", the evaluation should be incorporated into a societal test that considers both behind-the-meter and front-of-meter generation so that least-cost outcomes can be compared for various resource options

• TURN's cost effectiveness model was developed to provide the cost effectiveness showings required by the Commission. This model contains transparent user-modifiable input assumptions and is able to calculate a variety of results for 80 different IOU customer types including TRC, PCT, RIM, PAC, five different payback metrics, first year cost shift, and Internal Rate of Return.

• Successor tariff proposals should be evaluated using consistent payback metrics. TURN recommends the use of a "full discounted payback" for calculating a Market Transition Credit and other evaluation purposes.

• The Internal Rate of Return (IRR) realized by the participating customer is a useful metric for considering the benefits of participation in the successor tariff. It is appropriate to compare IRRs for customer generation with expected returns for other investments commonly made by these same customers and to consider the relative risks of various investments.

• Funds collected specifically from legacy NEM customers to support successor tariff participation by low-income customers are treated as cost under the RIM test but should be given special consideration if such contributions reduce the cost burden for all remaining non-legacy customers.

• Because non-rate funding sources used to incentivize new participation in a cost-based successor tariff are excluded from the RIM test, the use of these funding sources can significantly improve the cost-effectiveness of a successor tariff for non-participants and support the state's clean energy and electrification goals. At a minimum, the Commission should endorse a process to identify external funding sources that could be used to reduce the cost burden on all ratepayers for any successor tariff that is otherwise not cost effective

• The Commission should not base the adoption of a successor tariff on the need to achieve any specific pace of expected deployment or customer adoptions. Additionally, there is insufficient information presented in this proceeding to evaluate the optimal targets for behind-the-meter resource deployment through 2030. Any targets for BTM resource deployment should be developed in the Integrated Resource Planning proceeding based on a two-step process that evaluates resource costs and considers the rate impact of additional BTM deployment on all customers under a successor tariff.

• TURN's tariff proposal is fully consistent with the Guiding Principles adopted in D.21-02-007. Both the existing NEM 2.0 tariff, and the successor tariff proposals presented by the solar parties, are not consistent with these principles.

Joint Recommendations

• The Commission should endorse key elements of the Joint Recommendations relating to export compensation and a Grid Benefits Charge as an appropriate framework for evaluating the reasonableness of successor tariff proposals.

• Existing NEM 1.0 and 2.0 customers should be transitioned to the new successor tariff in a series of steps. Within five years of initial interconnection, non-CARE legacy participants should be shifted to a suitable electrification schedule and subject to a Grid Benefits Charge. Within eight years of initial interconnection, non-CARE legacy customers should be transitioned to the full end-state successor tariff.

• Prior to the implementation of the end-state successor tariff, the Commission should require all new NEM customer to enroll in a transitional tariff that requires participation in an electrification rate, sets export compensation at a defined percentage of retail rates for each IOU sufficient to support payback periods of less than 15 years, and has a duration of between 10 years (for SDG&E customers) and 15 years (PG&E and SCE customers). This interim tariff should provide higher export compensation to CARE customers in order to equalize payback periods with non-CARE customers.

• TURN's successor tariff is consistent with relevant provisions of the Joint Recommendations.

• The Joint Recommendations are reasonable, reflect a constructive effort of multiple parties to offer workable solutions, and are designed to balance the interests of participants and non-participating customers.

Elements of TURN's successor tariff

• Exports should be compensated at avoided cost using the two most recently adopted Avoided Cost Calculator (ACC) values. When utility real-time pricing tariffs are available, the ACC values should be modified to incorporate actual CAISO market prices to calculate the energy supply values.

• New successor tariff customers should have the option of locking into fixed hourly ACC-based export rates for defined terms of 5 or 10 years.

• NEM participants with stand-alone renewable generating units (no paired storage) should be permitted to take service under any of the future TOU tariffs for which they are eligible. Customers taking service under the proposed interim tariff, and customers with paired storage, should be required to enroll in an electrification tariff.

• Successor tariff customers should be required to pay a separate charge to recover Nonbypassable, Unavoidable and Shared (NUS) costs associated with the self-consumption of output provided by NEM-eligible BTM resources. TURN provides a list of rate components that should be characterized as NUS costs and can be modified by the Commission as appropriate. Customers should have the option of installing a second meter or accepting a production estimate to calculate self-consumption quantities.

• All subsidies under the successor tariff should be provided in the form of a one-time upfront Market Transition Credit (MTC) calibrated to achieve a target payback period for the participating customer. CARE customers should be eligible for an MTC set to achieve a 10-year discounted payback. Any ratepayer funded MTC incentives provided to Non-CARE customers should be focused on solar and paired storage installations. Non-CARE customers with stand-alone solar should only be eligible for an MTC if non-rate sources of funding are used or if the Commission finds that an MTC is necessary to align with the Title 24 New Solar Home Program. If the Commission wishes to adopt a ratepayer-funded MTC for non-CARE customers with stand-alone solar, the target payback period should be set to achieve an adequate combination of discounted payback and IRR.

• TURN's proposed MTC would provide an average incentive of $1,737 to $2,331 per kW-ac to achieve a 10-year discounted payback for CARE customers.

• A new surcharge should be applied to existing non-CARE NEM 1.0 and 2.0 residential customers to collect at least 50% of the costs of the MTC provided to new CARE successor tariff customers. Any remaining MTC costs recovered in rates should be collected from all customers through the Public Purpose Program charge allocated on an equal cents per kilowatt-hour basis.

• All new paired storage successor tariff customers, and any legacy NEM customer receiving an incentive through the Self-Generation Incentive Program, should be required to take service on an electrification rate. The IOUs should be directed to develop separate tariffs for paired storage customers that include additional Time of Use granularity and price signals better aligned with grid conditions.

• Because the TRC values are significantly better for solar and paired storage installations (as compared to stand-alone solar), the Commission should consider the merits of prioritizing MTC funding to support deployment of systems that include storage.

• Any paired storage unit participating in the successor tariff should have the capability to respond to remote dispatch instructions and be obligated to discharge during extreme system stress and emergency conditions (such as a CAISO stage 2 emergency) in support of overall grid needs. Medical baseline customers should be exempted from this obligation.

Concerns about other Party proposals

• Export compensation should not be tied to retail rates because this approach is not consistent with the statutory requirements, fails to align compensation with avoided cost values, unreasonably rewards participants for overall rate increases, and results in escalating cost shifts over time for each tranche of new enrollments.

• The export compensation proposals of SEIA/VS, CalSSA and Sierra Club tied to retail rates would significantly exceed ACC values for new customers enrolling in the successor tariff through 2030. This disconnect would continue for 20 years under these proposed tariffs.

• It is not appropriate to use levelized lifetime avoided cost values to set export compensation, an approach that results in a mismatch with the expected tariff duration, incorporate increasingly unreliable out-year values, and would provide excessive compensation to participants at the expense of all customers.

• Changes in federal tax benefits, particularly through an extension of the Investment Tax Credit currently expected to sunset after 2023, have a material impact on participant economics. The Commission should reject any successor tariff structure that fails to provide a method of adapting compensation to account for an extension or increase in federal tax incentives.

• Compensating participants for self-consumption at escalating retail rates, without applying any additional Grid Benefits Charge, would increase cost shifting to non-participants over the life of the system.

• Fixed Charges and Grid Benefit Charges proposed by other parties do not result in a quantification of cost responsibility that is as accurate, fair and transparent as TURN's NUS charge.

• Any collection of nonbypassable charges from successor tariff customers should not be limited to those authorized in D.16-01-044 but also include other charges collected on the same basis including the Power Charge Indifference Adjustment, New System Generation Costs, and various charges related to utility securitizations. Exempting successor tariff customers from these other nonbypassable charges would unreasonably shift the burden to other customers.

• The use of an increased minimum bill as a strategy to increase the collection of fixed or shared system costs from successor tariff customers fails to calibrate cost responsibility to customer size, would incentive BTM installations that avoid triggering the minimum bill threshold, could disincentivize conservation and efficiency, and are unlikely to collect sufficient revenues to prevent material cost shifting.

• Proposals to use the basic NEM 2.0 structure as end-state approaches for CARE and FERA customers do not represent durable, fair and scalable long-term solutions that are consistent with the guiding principles and statutory requirements.

Community Solar Virtual Net Energy Metering

• The adoption of a community solar tariff could yield higher cost effectiveness results for all customers, promote optimal deployment and orientation of generation, and minimize cost shifting to non-participants.

• The availability of a community solar tariff would provide an alternative for compliance with the Title 24 New Solar Homes Mandate that provides options to home builders and preserves the cost-effectiveness of the mandate regardless of the successor tariff adopted by the Commission.

• The Commission should adopt a modified version of CCSA's community solar proposal and consider additional refinements as part of an implementation phase of this proceeding. These modifications include adjustments to export compensation, more robust Commission oversight of customer contracts, a requirement that all Renewable Energy Credits be retired on behalf of subscribers, consideration of customer ownership models, and revisions to the structure and level of any proposed MTC.

Successor Tariff Implementation

- Implementation of the successor tariff should occur in three Phases that allow for immediate reforms and permit sufficient time to develop the elements of an "end-state" tariff that can go into effect no later than January 2024.

- Within 90 days of the adoption of a final decision, the Commission should authorize the interim tariff outlined in the Joint Recommendations. All new customers enrolling in net metering should be required to take service under this tariff and may remain on it for a period of up to 15 years (or 10 years for SDG&E customers).

- The second phase of implementation should involve formal and informal processes to refine key elements of an end-state successor tariff that result in a tariff available by January 1, 2024 for all new enrollments.

- The third phase of implementation should involve formal and informal processes to develop remaining enhancements to the end-state successor tariff including real-time pricing elements for energy supply values, instantaneous netting, and communication/dispatch protocols for paired storage. These elements should be incorporated into the end-state tariff by December 31, 2025.

III. RELEVANCE OF THE LOOKBACK STUDY TO CONSIDERATION OF THE SUCCESSOR TARIFF

The NEM 2.0 Lookback Study reinforces the need for major reforms that recalibrate the compensation to NEM participants to reflect the value provided to the grid and reduce or eliminate the cost shift to all customers. TURN's testimony and comments on the study summarize the scope of the cost shift, the oversubsidization of participants, and the inequities in cost effectiveness results and adoptions for participating CARE and non-CARE customers. The Commission should recognize that these results are inconsistent with guiding principle #1 (major misalignment between costs and benefits)[7] and guiding principle #2 (failure to ensure equity amongst customers).[8]

The NEM 2.0 Lookback Study highlights the massive cost shift associated with both the NEM 1.0 and NEM 2.0 tariffs and justifies major changes to participant compensation in a successor tariff. In the year 2020, the single year NEM 1.0 cost shift was estimated to be $1.093 billion (in $2012).[9] The net present value of the NEM 2.0 cost shift over 20 years was estimated to be over $13 billion.[10] Based on 616,308 NEM 1.0 systems and 413,982 NEM 2.0 systems interconnected on the grid by the end of 2019, the single year cost shift per NEM 1.0 customer in 2020 equals $1,600 and the 20-year present value cost shift per NEM 2.0 customer equals $31,402.[11] These values materially understate the cost shift since the Lookback Study relied on the 2020 Avoided Cost Calculator (ACC) to determine the benefits to all customers.[12] A recalculation of the NEM 2.0 cost shift using 2021 ACC values would yield <u>a significantly larger total cost shift</u> and cost shift per customer.

The Lookback study further found that the NEM 2.0 tariff has resulted in massive oversubsidization of residential participants with Participant Cost Test (PCT) values ranging from 1.62 to 2.08 depending upon the utility.[13] This combination of high PCT values and low residential Rate Impact Measure (RIM) test scores (averaging 0.32 for

---

[7] Guiding principle #1 requires compliance with the provisions of Public Utilities Code §2827.1 that require the successor tariff to be "based on the costs and benefits of the renewable electrical generation facility" (§2827.1(b)(3)) and to "ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs." (§2827.1(b)(4))
[8] As explained in testimony and prior comments (Ex. TRN-1, page 36), TURN believes that this principle requires the successor tariff to result in equal collection of unavoidable and nonbypassable charges from participating and non-participating customers, to ensure that NEM customers pay a fair share for the grid services they use, and ensuing equal compensation for similar generation regardless of the customer's household income.
[9] Ex. TRN-1, page 9; Ex. TRN-2, Attachment D, page 3.
[10] Ex. TRN-1, page 9, *citing* Lookback study, Table 5-1.
[11] Ex. TRN-1, page 9.
[12] Ex. TRN-1, page 9.
[13] Ex. TRN-1, page 10, *citing* Lookback study, page 6, Table 1-3

non-CARE customers) was accompanied by the finding that bill payments by residential NEM 2.0 customers, on average, covered between 9-18% of their cost of service.[14] This fact highlights the importance of designing a successor tariff that significantly reduces (or eliminates) ongoing cost-shifting and results in participants paying a far greater share of their cost of service.

The Lookback study also demonstrates the importance of reforming the successor tariff as it applies to low-income residential customers on California Alternate Rates for Energy (CARE) tariffs. The NEM 2.0 program yields lower participant cost test values and a longer payback period for CARE customers. The payback period for a CARE customer was estimated to be almost twice as long as a non-CARE customer.[15] Unsurprisingly, the Lookback study found that NEM 1.0 and NEM 2.0 system penetration increases with zip code median income.[16]

Updated information provided by the three IOUs shows that non-CARE customers are between 2.15 and 3.5 times as likely to be enrolled in a NEM tariff than CARE customers.[17] As of mid-2021, the enrollment data for each IOU is as follows:[18]

[14] Ex. TRN-1, page 10, *citing* Lookback Study, Tables 5-9 and 5-11
[15] Ex. TRN-1, page 10, *citing* Lookback study, page 94; Table 5-9
[16] Ex. TRN-1, page 10, *citing* Lookback study, page 33.
[17] Ex. TRN-1, page 10.
[18] Ex. TRN-1, pages 10-11. The 2.15 calculation applies to PG&E. The 3.5 calculation applies to SDG&E.

	% of residential customers enrolled in NEM 1.0	% of residential customers enrolled in NEM 2.0	% of residential customers enrolled in NEM 1.0 + 2.0
PG&E			
Non-CARE	6.5%	6.9%	13.4%
CARE	2.8%	3.4%	6.2%
SCE			
Non-CARE	5.9%	4.5%	10.4%
CARE	2.7%	1.9%	4.7%
SDG&E			
Non-CARE	8.6%	11.3%	19.9%
CARE	2.8%	3.4%	5.7%

This data is consistent with the recent characterization of the Lookback study by Commission staff. A 2021 Commission report detailing utility costs and affordability challenges offers the following observation:

> The evaluation study found that, as compared to the general California population, NEM customers are disproportionately older, located in high-income areas, likely to own their home, and less likely to live in a disadvantaged community. Consequently, the costs of NEM are disproportionately paid by younger, less wealthy, and more disadvantaged ratepayers, many of whom are renters. To address these concerns, the CPUC is considering modifying the structure of the NEM 2.0 tariff to achieve California's social and environmental goals for distributed renewable energy while allocating its costs and benefits in a more equitable manner.[19]

Both the Lookback Study and the CARE participation data compiled by TURN demonstrate that the existing NEM tariffs have disproportionately benefited non-CARE residential NEM customers. Any successor tariff revisions should include mechanisms to address this disparity, promote equity, provide adequate support (including ensuring equal compensation for self-consumption) to low-income customers and focus on methods of promoting adoption by low-income customers.

---

[19] Ex. TRN-1, page 11, *citing* Utility costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1, May 2021, California Public Utilities Commission, page 30

IV. METHODS OF ANALYZING PROGRAM ELEMENTS THAT COMPLY WITH THE GUIDING PRINCIPLES

TURN's proposal and testimony outline a variety of methods for analyzing the alignment between successor tariff proposals and the guiding principles. TURN's analysis focuses on quantitative metrics relating to cost effectiveness, cost shifting, and participant benefits. These metrics should serve as the primary basis for assessing successor tariff alternatives consistent with the applicable statutory requirements. Since compliance with some of the guiding principles cannot be satisfied through pure quantitative metrics, TURN provides perspective on methods for determining compliance with these other principles after reviewing quantitative approaches.

A. Importance of using RIM, PCT, TRC, PAC tests to assess the cost-effectiveness of a successor tariff

In D.21-02-007, the Commission explained that, pursuant to D.19-05-019, the Total Resource Cost (TRC) test is the "primary test" for use in assessing the cost-effectiveness of Distributed Energy Resources but that results from the Program Administrator Cost (PAC) test, Ratepayer Impact Measure (RIM) test, and Participant Cost Test (PCT) should also be considered for purposes of evaluating NEM successor tariff proposals.[20] Consistent with this direction, TURN provided cost-effectiveness results for its tariff proposal under these four primary Standard Practice Manual (SPM) approaches and produced PCT, RIM and TRC results for a number of other tariff proposals submitted by other parties.[21] These results were generated through the cost effectiveness model that TURN developed over the course of this proceeding to ensure that the full suite of SPM cost tests could be applied to various successor tariff options using both the 2020 and 2021 ACC values.

[20] D.21-02-007, pages 12, 35-36

[21] Despite explicit direction from the Commission on this point, many other parties failed to provide this analysis for their tariff proposals or conducted analysis that did not incorporate the 2021 Avoided Cost Calculator values.

As explained in the following sections, the Commission should rely on the RIM and PCT tests to assess the differences between successor tariff proposals and determine the impact of individual proposal elements on participating customers and on all ratepayers to whom such costs are allocated ("all ratepayers"). The TRC test should be relied upon for the threshold determination regarding the cost-effectiveness of programs to promote BTM stand-alone renewable generation and generation that is paired with energy storage. TURN does not believe that the PAC test is useful for any purpose in this proceeding.

1. *Total Resource Cost (TRC) test*

The TRC test benefit-cost ratio is the ratio of the discounted total benefits of the program to the discounted total costs of a program over a specified time period.[22] A benefit-cost ratio greater than one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.[23] Under the TRC, the benefits quantified are the avoided supply costs, the reduction in transmission, distribution, and generation capacity costs valued at marginal cost for the periods when there is a load reduction ("avoided costs" or "AC").[24] The costs quantified are the program costs paid by both the utility and participants, plus any increase in supply costs for the periods in which load is increased.[25]

The key elements of tariff design, including any incentives, various approaches to export compensation, netting, self-consumption, and grid charges, are <u>not quantified</u> in the TRC results. The Commission cannot therefore use the TRC test to evaluate the cost-effectiveness impacts of different tariff options. As a result, the only methods of materially changing the results of the TRC test are to modify the resource type (i.e.,

---

[22] Ex. TRN-1, page 12, *citing* California Standard Practice Manual (SPM).
[23] Ex. TRN-1, page 12, *citing* California SPM.
[24] Ex. TRN-1, page 13, *citing* California SPM.
[25] Ex. TRN-1, page 13. All equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs (no matter who pays for them) are included in this test. Any tax credits are considered a reduction to costs.

wind, paired storage) and/or generation profile, assume different system costs paid by the participant, and/or assume different utility administration costs. For example, analysis that relies on 2020 ACC values, rather than the 2021 ACC values parties were directed to use, would result in TRC results that produce anomalously high values.

TURN used its model to calculate average TRC results for residential standalone solar installations by utility and customer type (CARE/Non-CARE) assuming either an upfront purchase or a leasing arrangement. The results are as follows:[26]

TURN Successor Tariff Proposal – TRC Results Residential Standalone Solar (2021 ACC values)				
Customer Type	**Finance Method**	**PG&E**	**SCE**	**SDG&E**
CARE	Upfront Purchase	0.48	0.51	0.45
Non-CARE	Upfront Purchase	0.52	0.56	0.49
CARE	Lease	0.38	0.43	0.36
Non-CARE	Lease	0.38	0.43	0.36

These results indicate that the NEM 3.0 program for residential standalone solar technology is not expected to be beneficial to the utility and its ratepayers on a total resource cost basis. The results also indicate that under the upfront purchase scenario, CARE customer results are modestly lower than non-CARE results. This is due to the higher finance costs assumed for CARE in the upfront purchase scenario. To the extent that the Commission relies on the TRC to guide its decisionmaking in this proceeding, the results show that measures designed to increase standalone behind-the-meter solar resource deployment are not cost justified.

TURN's analysis also shows a significantly higher TRC value for customer-owned solar generation that is paired with energy storage versus a standalone solar installation.[27]

[26] Ex. TRN-1, page 66.
[27] Ex. TRN-3, pages 71-72.

While the values are below 1.0, the improvements in value provided by paired storage indicate that focusing on these configurations would cause a successor tariff to yield higher TRC results. The improvements in TRC, PCT and RIM results for paired storage are the basis for TURN's proposal to focus any MTC provided to non-CARE customers on installations that include paired storage.

2. *Ratepayer Impact Measure (RIM) test*

The RIM test is the only approach that properly accounts for the impact of NEM successor tariff design on all customers. The RIM test compares the benefits received by all customers (primarily avoided cost savings) with the incremental costs incurred to serve participating customers including utility program costs, incentives paid to participants, and decreased revenues received from participants.[28] Because the RIM test compares the benefits of the tariff to all ratepayers with the costs to all ratepayers, it fairly quantifies the degree of cost shift from participants to all ratepayers.

If the successor tariff reduces utility revenues by less than any reduction in utility costs, rates for all customers will decline. If a successor tariff reduces utility revenues by more than the reduction in utility costs, rates for all customers will increase.[29] The RIM test uses the relevant input data to indicate the direction and magnitude of the expected change in customer bills or rate levels.[30] A RIM benefit-cost ratio result over 1.0 indicates that the tariff will lower rates and bills while a score below 1.0 indicates that the tariff will increase rates and bills for non-participating customers.

---

[28] Ex.TRN-1, page 14. As outlined in the SPM, the benefits calculated in the RIM test are the savings from avoided costs plus the program fees paid by participants. The costs are the program costs incurred by the utility in creating or administering the program, the incentives paid to the participant that are sourced from utility rates, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).
[29] Ex. TRN-1, page 14, *citing* California SPM, page 14.
[30] Ex. TRN-1, page 14, *citing* California SPM, page 13.

Since the RIM test is designed to calculate the cost shift associated with a successor tariff proposal, it should be used to compare the impact of various successor tariff proposal submitted by parties in this proceeding. TURN's analysis finds that the existing NEM 2.0 tariff yields very low RIM scores for residential customers (ranging from 0.12 to 0.23 for non-CARE customers and 0.18 to 0.32 for CARE customers).[31] TURN's successor tariff proposal yields RIM results that range from 0.57 to 1.81 depending upon the customer load profile (large v. small, CARE v. Non-CARE, dual fuel v. all electric, inland v. coastal climate zone and whether onsite EV charging is occurring).[32] Results for non-CARE customers are significantly higher than CARE customers who are assumed to receive a Market Transition Credit funded through customer rates. By comparison, many of the tariffs proposed by the solar parties (CalSSA, SEIA/VS) show RIM scores that are in the range of 0.12-0.26 for both Non-CARE and CARE residential customers.[33]

The extreme cost shifting produced by various tariff proposals, as demonstrated by the solar party RIM results, should be scrutinized by the Commission given the relevant statutory requirements that govern the program. Specifically, Public Utilities Code §2827.1(b)(3) requires the tariff to be "based on the costs and benefits" of the system and §2827.1(b)(4) requires that the "total benefits" of the tariff "to all customers and the electrical system are approximately equal to the total costs."[34] These requirements are also enshrined in Guiding Principle #1.

---

[31] Ex. TRN-1, page 76.
[32] Ex. TRN-1, page 70. TURN provides a full suite of results for a variety of customer types of all three IOUs in the attachments to its direct testimony (Ex. TRN-2, Attachment B).
[33] Ex. TRN-3, pages 85-91, Tables 13-20.
[34] Pub. Util. Code §2827.1(b)(3), (b)(4).

3. *Participant Cost Test (PCT)*

The PCT reflects the value proposition for the participating customer and is a proxy for cost-effectiveness from their perspective. The PCT is the measure of the quantifiable benefits and costs to the customer due to participation in a program. These benefits comprise the reduction in the customer's utility bill, incentives, and tax credits).[35] Benefits such as commitment to environmentalism, desire for energy independence and resilience are not included in the PCT but may constitute tangible values that motivate customers to invest in their own generation resources.[36] The PCT measures costs to the participant in the form of initial and ongoing expenses plus any increase in utility bills.[37] The TURN and E3 PCT values are based on a 20-year analysis of total costs and benefits. This 20-year duration matches the expected term of the successor tariff. TURN also provides some PCT results over both 10 and 20 years to illustrate whether participant benefits are expected to be front-loaded or back-loaded over the 20-year period.[38]

The PCT benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk.[39] A benefit-cost ratio greater than 1.0 indicates a beneficial program for the participant. The Commission should recognize that the PCT represents a useful metric for assessing the total benefits of a particular tariff option to the participating customer. Because the PCT is tied to the specifics of tariff design, it allows the Commission to consider the relative attractiveness of existing and proposed tariffs under consideration.

---

[35] Ex. TRN-1, page 15, *citing* California SPM, page 8.
[36] Ex. TRN-1, page 15.
[37] Ex. TRN-1, page 15, *citing* California SPM, page 8. Costs include any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs;3 any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.
[38] Ex. TRN-3, pages 85-91, Tables 13-20.
[39] Ex. TRN-1, page 15, *citing* California SPM, page 9

TURN's analysis finds that the existing NEM 2.0 tariff yields very robust PCT results for residential standalone solar customers (ranging from 1.8 to 2.52 for Non-CARE customers and 1.3 to 1.72 for CARE customers).[40] TURN's analysis of tariffs proposed by the solar parties show PCT scores for residential standalone solar installations ranging from 1.75 to 2.37 for non-CARE customers and 1.58 to 1.89 for CARE customers.[41] TURN's tariff proposal yields average PCT values below 1.0 for both CARE and Non-CARE customers without any Market Transition Credit. With an MTC, TURN's proposal yields PCT values greater than 1.0 for both CARE and Non-CARE customers.[42] Assuming an MTC with a 10-year discounted payback period, TURN's proposed successor tariff would produce PCT values ranging between 1.11 and 1.19 for CARE customers of the three IOUs with standalone solar installations.[43]

TURN urges the Commission to review the PCT results in combination with payback periods and internal rates of return to assess the overall attractiveness of a successor tariff proposal to prospective customers. These combined metrics should provide a complete portrait of the net quantifiable benefits that a participant would expect to realize from a successor tariff.

4. Program Administrator Cost Test (PAC)

The Commission directed parties proposing successor tariff options to provide Program Administrator Cost (PAC) test results for review and consideration.[44] The PAC test measures the net costs of a demand-side management program as a resource option based only on the costs incurred by the program administrator (including incentive

[40] Ex. TRN-1, page 76.
[41] Ex. TRN-3, pages 85-91, Tables 13-20. The "solar parties" are the California Solar and Storage Association (CalSSA) and the Solar Energy Industries Association/Vote Solar (SEIA/VS).
[42] Ex. TRN-3, pages 85-91, Tables 13-20. TURN models an MTC for non-CARE customers with a 15-year discounted payback and an MTC for CARE customers with 10 and 13-year paybacks.
[43] Ex. TRN-1, page 74.
[44] D.21-02-007, Finding of Fact 4

costs) and excluding any net costs incurred by the participant.[45] Although TURN provides PAC test results for its successor tariff, the modeling performed by E3 and practically all other parties did not include PAC test results.[46]

The PAC ignores both costs spent by participants to purchase/lease and operate a Behind the Meter (BTM) resource and the bill savings/lost revenues that are used to assess cost shifting.[47] The actual design of the tariff has no impact on the PAC test results. Any differences in results under the PAC test between existing NEM 2.0 and proposed successor tariffs are attributable to the inclusion of incremental costs associated with utility administration.[48] Because of the narrow scope of the PAC test, it is not useful for assessing the cost-effectiveness of successor tariff options and should not be given any weight by the Commission in this proceeding.

B. Alternative approaches to calculating TRC, RIM and PCT values should be rejected

Several party proposals employ non-standard methods of calculating Total Resource Cost (TRC), Rate Impact Measure (RIM) and Participant Cost Test (PCT) values. The Commission should reject these approaches because they deviate from established practice and do not accurately portray the cost effectiveness of the modeled resources from the relevant perspective of society, all customers, and participants.

---

[45] Ex. TRN-1, page 16. The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The costs for the PAC test are those incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).
[46] Ex. TRN-1, page 66; Ex. TRN-2, Attachment B.
[47] Ex. TRN-1, page 17.
[48] For example, TURN's successor tariff would require IOUs to incur costs to estimate or meter generation from the generating unit.

1. *Cost-effectiveness analysis term should match the term of the successor tariff*

While both SEIA/VS and CalSSA assume that the term of a successor tariff is 20 years, both parties model key successor tariff proposal elements using 25-year values for avoided costs, rate escalation and other key inputs.[49] TURN opposes the use of 25-year values to model a 20-year tariff proposal. This approach is designed to produce artificially inflated RIM, PCT, and TRC values that justify the tariffs proposed by these parties.

To demonstrate the bias introduced by the use of 25-year values, TURN recalculated the cost-effectiveness showing contained in the SEIA/VS testimony for a 2023 stand-alone solar installation (using 2020 ACC values, which are now outdated as a result of the 2021 ACC). The following table shows the impact of relying on 25-year vs. 20-year values to assess the SEIA/VS proposal:[50]

Comparison of SEIA/VS SPM Results for 20- and 25-year analysis terms assuming 2020 ACC and SEIA/VS inputs[51]									
	RIM	**RIM**	**RIM**	**PCT**	**PCT**	**PCT**	**TRC**	**TRC**	**TRC**
	PG&E	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
20 year results	0.49	0.57	0.44	1.74	1.69	1.96	0.86	0.96	0.87
25 year results	0.56	0.61	0.49	1.81	1.87	2.10	1.01	1.13	1.02

These results show that both RIM and TRC results are higher for a 25-year analysis term than for a 20-year term. <u>The RIM and TRC results would also be significantly lower if 2021 ACC values were used</u>. Regardless of the ACC values selected, the Commission should require the period of cost-effectiveness analysis to be consistent with the tariff duration. Neither solar party identifies what tariff customers would be served under

---

[49] Ex. SVS-3, pages 13, 24; Ex. CSA-1, pages 10, 13.
[50] Ex. TRN-3, page 15, Table 1.
[51] This analysis uses the SEIA/VS workpapers and therefore does not rely on the input assumptions used in TURN's model. <u>TURN does not endorse the reasonableness of these results and notes that they rely on 2020 ACC values</u> but provides them only for purpose of comparing 20 and 25 year values.

after year 20, which raises the further concern that the values for years 21-25 could ultimately be double counted both in an evaluation of the currently proposed tariffs and in evaluating tariffs to be available starting in year 21.[52]

2. *Cost-effectiveness should be calculated for each technology*

SEIA/VS calculates RIM scores for a blend of solar and solar with paired storage installations for each step of its successor tariff.[53] These results fail to separately characterize the cost-effectiveness of individual technologies and installations. As a result, the required presentation of cost effectiveness results by SEIA/VS confuses rather than informs. In addition, SEIA/VS includes separately calculated "resiliency benefits" for solar with paired storage, which serves to further inflate the blended RIM scores shown in its rebuttal testimony.[54] The presentation of blended RIM scores masks the poorer results for stand-alone solar under the SEIA/VS tariff.[55]

In assessing the impact of individual tariff options on various types of customer adoption, the Commission should reject the use of blended cost-effectiveness scores. The Commission should instead review individual technology cost-effectiveness results as the basis for authorizing incentives specific to each technology or application. Moreover, analysis that assumes a weighting of different technologies over time is inherently unreliable given uncertainties over rates of customer adoption of various technologies.

TURN separately analyzed solar and solar with paired storage installations for purposes of assessing cost-effectiveness. This analysis supports the finding that the Commission should prioritize solar with paired storage technology for the receipt of any ratepayer-funded Non-CARE subsidies because for the same level of incentive, the

[52] RT Vol. 7, page 1157, Heavner.
[53] RT Vol. 8, page 1292, Beach.
[54] RT Vol. 8, page 1293, Beach
[55] RT Vol. 8, page 1292, Beach

cost-effectiveness of solar with paired storage is greater than that for stand-alone solar installations.[56] The Commission should use these findings to consider whether, and how, to focus the use of scarce ratepayer subsidies on the most cost effective strategies to achieve the state's clean energy objectives.

3. Cost effectiveness results should not be averaged over time

SEIA/VS provides TRC results for customer generation in the form of averages over the 2022 through 2030 period.[57] This approach obscures the impact of their successor tariff proposal for each installation year and each utility. The resulting presentation obscures more granular TRC results and boosts the claimed value of stand-alone solar by 25% relative to the first-year values to be expected in 2023.[58] Moreover, this approach fails to show the cost effectiveness of tariffs applied to each customer tranche over the relevant timeframe. Because SEIA/VS propose a set of different tariffs that would apply over this period, the Commission should require modeling of each tariff configuration (or Step) and technology (standalone solar, solar with paired storage) in order to assess reasonableness and consistency with the guiding principles.

4. Resiliency benefits should not be added to the TRC and RIM Results

SEIA/VS provide TRC results for paired solar and storage systems that incorporate "resiliency benefits" realized by the participating customer as part of a cost effectiveness showing.[59] SBUA similarly argues that the omission of resiliency values from the TRC, PCT and RIM tests underestimates the "benefits" of paired solar and storage installations.[60] TURN does not support including resiliency values in any of the cost tests (including the Societal Test). Resiliency is not quantified in retail rates, the cost of the resource, or in the avoided cost calculator. It is therefore properly excluded from

---

[56] Ex. TRN-3, pages 71-72.
[57] Ex. SVS-1, page 19.
[58] Ex. TRN-3, page 19.
[59] Ex. SVS-1, page 19 ("With the resiliency benefits included, the TRC score for solar-plus-storage increases to 1.41")
[60] Ex. SBU-1, page 14

the TRC and RIM tests. To the extent that the Commission agrees that a customer adopting solar with paired storage realizes some resiliency benefits, those values should be limited to inclusion in the PCT.

Regarding the Societal Test, the resiliency benefits assumed by many parties are those that are realized exclusively by the participating customer who remains energized during an outage. Nevertheless, SEIA/VS argues that these private benefits should be credited to all customers based on the belief that any customer with storage will share excess power and services with neighbors during an extended outage.[61] Under cross-examination, SEIA/VS witness Beach rejected the notion that any customer who remains energized during an outage would refuse to share excess with their neighbors, characterizing such an outcome as "unrealistic."[62] However, SEIA/VS oppose any requirement that customers with energy storage make any services available to neighbors under such circumstances.[63] Absent a specific demonstration that resiliency benefits would be shared with, and realized by, non-participating customers, they should be deemed private benefits that are not appropriately included in the Societal Test.

The Commission should reject proposals that conflate public and private resiliency benefits for purposes of boosting the claimed cost-effectiveness of a successor tariff. Unless a customer provides a core public service, operates a critical facility that serves the public, or can assist the grid in withstanding or recovering from a major, event-induced outage, there is no basis to credit the customer's private resiliency benefits to society for purposes of assessing the cost-effectiveness of a successor tariff. A customer that can operate their refrigerator, watch television, do their laundry, play video games, or charge their electric vehicle during an outage is not providing a benefit to others. The opportunities to capture these private resiliency benefits are the reason that customers

---

[61] Ex. TRN-10, SEIA/VS Response to TURN Data Request 2, Q11.
[62] RT Vol. 8, page 1336, Beach.
[63] Ex. TRN-10, SEIA/VS Response to TURN Data Request 2, Q11(c).

are willing to invest in storage today despite long payback periods under current tariffs.[64] SEIA/VS witness Beach admitted that the existence of these benefits justifies "a longer payback" for a customer that invests in energy storage.[65]

There is no general view amongst the parties on the method for considering what types of events allow for resiliency benefits. For example, SEIA/VS witness Beach suggested that only outages representing "dark-sky" events that are "measured in days" should be considered, a metric that excludes short-term outages and Public Safety Power Shutoff (PSPS) events for most customers.[66] It is not clear whether other parties also limit their consideration of resiliency to these extreme events.

Even for these extreme events, the calculation of resiliency benefits is highly problematic. The resiliency calculation performed by SEIA/VS assumes that the avoided cost of installing a gas-powered generator capable of providing power during 7 days (out of every 10 years) represents the "benefits" of an energy storage system to all customers.[67] Yet SEIA/VS propose that this resiliency benefit, which is based on fossil fuel generation, be used to justify tariffs that subsidize customer installations energy storage. According to SEIA/VS witness Beach, a gas-powered generator and a battery provide identical "resiliency" benefits to the customer, and to the neighborhood, over the 7-day outage period modeled.[68] This analysis suggests that new ratepayer-funded subsidies to deploy gas powered generators by individual customers would also be cost-justified.

There is insufficient evidence in this proceeding to reach any findings with respect to resiliency value. If the Commission wishes to adopt values for technologies that allow individual customers to remain energized during outages, this effort should occur in a

[64] Ex. TRN-1, page 56.
[65] RT Vol. 8, pages 1324-1325, Beach.
[66] RT Vol. 8, page 1338, Beach.
[67] RT Vol. 8, page 1341, Beach.
[68] RT Vol. 8, pages 1343-1344, Beach.

process that reviews different technologies and evaluates the extent to which a customer is strategically located, offers particular services during outages, and is likely to provide specific support to their community. The use of generic, one-off values for this purpose in the current proceeding does little to answer any of these questions and should be rejected.

5. *CalSSA modified export-only RIM test should not be employed*

The Ratepayer Impact Measure (RIM) test quantifies whether the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.[69] In D.19-05-019, the Commission established that all activities "requiring cost-effectiveness of distributed energy resources" should "review and consider" the results of the RIM test.[70] The Commission did not distinguish between the application of the RIM test to distributed energy resource programs that involve exported electricity and those that result only in demand reductions.

To support its arguments regarding cost shifting, CalSSA provides a RIM quantification based only on the costs and benefits of exported electricity.[71] This quantification ignores the crediting mechanism for self-consumption quantities and the lost rate revenues that must be absorbed by all customers. Instead, CalSSA's approach merely compares the value of solar-weighted exports using 25-year levelized ACC values with the compensation that would be provided to the customer under its proposed export compensation rate.[72] By design, it cannot be used for any distributed energy resource that fails to result in electricity exports.[73]

---

[69] Ex. TRN-3, page 20. The benefits calculated in the RIM test are the savings from avoided costs plus the program fees paid by participants. The costs include the program costs incurred by the utility in creating or administering the program, incentives paid to the participant, and decreased revenues for any periods in which load has been decreased.
[70] D.19-05-019, Ordering Paragraph 2.
[71] Ex. CSA-1, page 79.
[72] RT Vol. 7, page 1160, Heavner.
[73] RT Vol. 7, page 1161, Heavner.

The CalSSA approach is fundamentally inconsistent with the California Standard Practice Manual which does not limit quantification of avoided costs or quantification of decreased revenues to export periods.[74] As explained in the SPM, the RIM test is designed to assess the cost shifting impacts of demand-side management programs including energy efficiency, demand response, load management, and fuel substitution.[75] Most of these programs involve reductions in demand and do not result in any electricity exports. During hearings, witnesses from the solar parties acknowledged that the RIM test proposed by CalSSA cannot be used for any DER that does not export electricity.[76] Moreover, the export-only RIM test cannot compare tariff alternatives that include various levels of fixed charges or grid benefit charges because it does not assess the impact of self-consumption. As a result, it is not a test that can provide the Commission with any ability to assess the cost-effectiveness of alternative successor tariff options and the cost shifting that may result.[77]

As explained in the Standard Practice Manual, "under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program."[78] The Commission should reject efforts to fundamentally limit the RIM test by applying it only to electricity exports. These limits are not helpful in understanding the impact of a successor tariff proposal on all customers.

6. *Societal benefit calculations should only be considered using a standard approach (Societal Test) that also evaluates front-of-meter alternatives*

SEIA/VS provide a quantification of "societal benefits" expected to result from new behind the meter solar and paired storage projects. The list of benefits included in this

---

[74] Ex. TRN-3, page 21, *citing* CPUC Standard Practice Manual, page 13.
[75] Ex. TRN-3, page 21, *citing* CPUC Standard Practice Manual, page 14.
[76] RT Vol. 8, page 1304, Beach.
[77] RT Vol. 7, page 1164, Heavner (CalSSA did not apply its export-only RIM test to any other tariff proposal).
[78] Ex. TRN-3, page 21, *citing* CPUC Standard Practice Manual, page 14.

calculation include avoided out-of-state methane leakage, social cost of carbon, avoided water use, health benefits, local economic benefits, and land use.[79] This analysis should not be relied upon for purposes of evaluating successor tariff options.

According to the California Standard Practice Manual, these benefits should be considered as part of a Societal Test that is a distinct variant of the TRC test. The Societal Test differs from the TRC test in that it includes the effects of externalities (*e.g.* environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.[80] The Societal Test attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). Key differences include that tax credits and interest payments are treated as a transfer payments and the incorporation of a societal discount rate.[81]

Despite expressing support for the consideration of "societal benefits", SEIA/VS do not provide Societal Test results, making it impossible to rank their successor proposal on this metric. No party presented Societal Test results in support of their proposals in this proceeding.[82] Furthermore, front-of-meter renewable and zero carbon generation and storage also have the potential to yield a variety of "societal benefits", to the extent they exist, potentially at far lower cost to all customers relative to behind-the-meter generation. During cross-examination, SEIA/VS witness Beach opposed the notion that a similar calculation should be performed for other utility programs even if they generate the same objective benefits as customer-owned generation.[83] By cherry-picking any potential societal benefits of customer-sited generation and considering them in isolation, without any comparison to alternatives, SEIA/VS fail to provide any rational basis for the Commission to evaluate these values in this proceeding.

---

[79] Ex. SVS-1, pages 20-21.
[80] Ex. TRN-3, page 22, *citing* CPUC Standard Practice Manual, page 18
[81] Ex. TRN-3, page 22, *citing* CPUC Standard Practice Manual, page 19.
[82] RT Vol. 9, page 1630, Chait.
[83] RT Vol. 8, page 1350, Beach.

If the Commission desires to incorporate "societal benefits" in its analysis of successor tariff-eligible generation, it should conduct an evaluation that includes front-of-meter generation so that outcomes can be compared for various resource options with the goal of adopting a policy that produces least cost results. SEIA/VS witness Beach acknowledged, during cross examination, that front-of-meter resources could provide such benefits but declined to include any such analysis in his testimony.[84] Absent such an analysis that evaluates various alternatives, the Commission should not adopt the *a priori* assumption that the best, or most cost-effective, way to maximize "societal benefits" is through the subsidization of behind-the-meter resources. If the Commission wishes to authorize additional expenditures of ratepayer funds to achieve such benefits, the least costly method of achieving them should be given priority.

C. <u>TURN cost effectiveness model</u>

In comments on the OIR filed last year, TURN urged the Commission to develop or identify analytical tools that could be used to evaluate successor tariff options presented in this proceeding.[85] This proposal was based on the expectation that party proposals would be difficult to compare without a standard point of reference that could produce apples-to-apples results on key metrics. The Commission did not identify or reference any such tool in either the November 19, 2020 scoping memo or the Decision adopting the guiding principles (D.21-02-007). However, the Commission did direct parties to demonstrate the cost effectiveness of their tariff proposals in the manner directed by D.19-05-019 through results under the TRC, RIM, PCT and PAC tests.[86]

In order to provide these cost effectiveness showings, TURN developed its own successor tariff evaluation model for use in this proceeding (TURN Model). The Excel model contains transparent input assumptions that may be modified by users, does not include any confidential material, and was made available for download and use by all

[84] RT Vol. 8, page 1350, Beach.
[85] TURN comments on preliminary scope and schedule, October 5, 2020, pages 10-11.
[86] D.21-02-007, pages 7, 12, 35, 36, Finding of Fact #4.

parties via a public download link.[87] TURN provided a comprehensive description of its model inputs and logic in both its original tariff proposal and direct testimony.[88]

The purpose of the TURN Model is to calculate Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant Cost Test (PCT) and Program Administrator Cost (PAC) test results, payback results, first year cost shift, and Internal Rate of Return (IRR) results, for a given Utility, Customer, Distributed Energy Resource (DER) Type, and Successor Tariff (ST) characterization, with the goal of designing a ST that conforms to the Guiding Principles.[89] TURN's model accommodates up to 32 separate load shapes for each IOU (with over 80 load shapes modeled in total), provides results using both the 2020 and 2021 ACC values and can model both stand-alone solar installations and those that include paired energy storage.[90]

Subsequent to the development of TURN's model, the Commission modified the schedule of the proceeding and directed parties to provide successor tariff design information to E3 for use in a neutral modeling exercise.[91] In prepared testimony, TURN demonstrated that the results produced by its model are comparable to those produced by E3 and explained the basis for any differences.[92] TURN's model provides significant additional functionality beyond the E3 model including results for installation years 2022, 2024 and 2025, five different payback metrics (simple, E3 payback, escalated simple, simple discounted and full discounted), Internal Rates of Return, Program Administrator Cost (PAC) test results, and MTC values needed to achieve a specific target payback for the selected customer.[93]

---

[87] Ex. TRN-1, pages 20-21.
[88] Ex. TRN-1, pages 20-31; Ex. TRN-2, Attachment C (TURN March 15, 2021 Tariff Proposal), Appendix A (Description of TURN Model).
[89] Ex. TRN-1, page 21.
[90] Ex. TRN-1, pages 21, 24.
[91] ALJ ruling noticing April 22, 2021 Workshop and Revising Procedural Schedule, issued April 8, 2021.
[92] Ex. TRN-1, pages 28-31, 63-65.
[93] Ex. TRN-1, pages 20, 23-24, 69.

TURN's testimony provides results from the model for its own successor tariff proposal, including various permutations of that proposal, and the tariff proposals submitted by several other parties. The Commission should recognize the significant value that TURN's model adds to the proceeding and give weight to the results highlighted in TURN's direct and rebuttal testimony. These results allow the Commission to analyze multiple dimensions of cost effectiveness and inform a more comprehensive understanding of how various tariff elements affect key metrics.

D. Other methods of evaluation that should be considered by the Commission

1. Payback period

The payback period is generally understood to represent the length of time required for participating customer bill savings to recover the participating customer's investment in the NEM-eligible resource. TURN's testimony provided an overview of different payback period metrics that should be considered.[94] Several parties fail to adequately distinguish between different payback methods in presenting their results and/or analyzing other party proposals.[95] Since many parties use different payback metrics interchangeably or without clear definitions, TURN urges the Commission to ensure that any reliance on payback periods uses consistent metrics and does not conflate the various approaches.

TURN explained the five basic payback methods that may be used. These include simple payback, escalated simple payback, simple discounted payback, E3 payback, and full discounted payback. These metrics produce varying results depending upon

---

[94] Ex. TRN-1, pages 17-19.

[95] Ex. TRN-3, page 24; For example, CalSSA presents results for simple and discounted paybacks but does not describe how they are calculated (Ex. CSA-1, page 72); SEIA/VS conflates simple payback metrics with the payback metric used in the E3 analysis - the E3 payback metric yields longer periods due to the inclusion of the present value of operating expenses (Ex. SVS-1, pages 52, 55)

the sensitivity of paybacks to retail rate escalation, the extent of ongoing participant costs, and the discount rate applied to participants. TURN presents results for all five payback metrics for each customer profile (and for all three IOUs) in the complete results of its model runs.[96]

For purposes of presenting results in testimony, TURN placed greater reliance on the simple payback and the full discounted payback since these metrics are typically used for purposes of analysis and comparison. TURN prefers the use of the full discounted payback which, although typically yielding longer timeframes, can quantify either a stream of annual lease costs, or a scenario where a participating customer purchases a resource upfront and finances the resource over time.[97] This metric yields the year in which a customer is able to fully recover 20 years of costs relating to the system. For purposes of comparison, TURN's 10-year discounted payback for a CARE standalone solar customer can result in a <u>simple</u> payback of as little as 5 years and a 15-year discounted payback for a non-CARE standalone solar customer can result in a <u>simple</u> payback as low as 7.7 years.[98] The significant differences in results under these approaches justify careful scrutiny of party claims regarding appropriate payback periods.

The following table highlights the results of payback period analysis from TURN's modeling of its successor tariff for each of the three IOUs assuming that a CARE customer receives an incentive sufficient to achieve a 10-year full discounted payback:[99]

---

96 Ex. TRN-2, Attachment B.
97 Ex. TRN-1, page 18.
98 Ex. TRN-3, pages 85, 88.
99 Ex. TRN-1, page 76.

TURN Successor Tariff Proposal CARE Customer Standalone Solar Results with MTC incentive			
Payback Metric	**PG&E**	**SCE**	**SDG&E**
Average Simple Payback (years)	6.0	5.3	5.1
Average Escalated Simple Payback (years)	6.8	6.2	6.0
Average Simple Discounted Payback (years)	8.6	7.9	7.7
Average E3 Payback (years)	7.7	8.1	7.9
Average Full Discounted Payback (years)	10.0	10.0	10.0
Average IRR (%)	15.7%	18.5%	20.0%

These results demonstrate the wide range of outcomes under various payback metrics and emphasize the importance of using common metrics for any comparison of outcomes under different tariff options.

The full discounted payback metric does not reveal the extent to which a customer realizes positive cash flow (defined as annual bill savings exceeding annual expenses) in any particular year. For example, TURN modeled its successor tariff for two types of standalone solar customers (one PG&E and other SDG&E) expected to achieve full discounted paybacks in 13 and 17 years. In both cases, the customer's expected bill savings exceeds the cost of energy from their solar generator over the first 10 years.[100] For another SDG&E Non-CARE customer projected to receive a full discounted payback in 12 years, the customer realizes a net bill savings (bill savings minus levelized cost of solar generation) of 4.3 cents/kWh over the first five years and 6.6 cents/kWh over the first 10 years.[101] These examples highlight the fact that a tariff expected to produce a full discounted payback in a future year may still result in the customer realizing net savings in every year.

---

[100] Ex. TRN-2, Attachment B, UpfNoBNOl, page 1 of 12 (PG&E Non-CARE/Coastal/Dual Fuel/Large/No EV), page 12 of 12 (SDG&E Non-CARE/Inland/All Electric/Large/No EV).
[101] Ex. TRN-2, Attachment B, UpfNoBNOl, page 11 of 12 (SDG&E Non-CARE/Coastal/All Electric/Large/No EV).

For purposes of developing a Market Transition Credit (MTC), TURN's model calculates the appropriate subsidy value to achieve a specifically determined full discounted payback period. TURN presents results for CARE customers under 10 and 13 year payback periods[102] and for non-CARE customers under both 10 and 15 year payback periods.[103] In its analysis, E3 provides MTC results for payback periods of 5, 7.5, 10, and 12.5 years based on the "E3 payback" metric (which differs from the full discounted payback periods modeled by TURN).[104] If the Commission determines that a different period is appropriate for purposes of tariff design, it can authorize the provision of an MTC to achieve that target payback using the appropriate payback metric. In addition, TURN's proposed NUS charge can be modified (by removing cost components) to reduce the costs collected from successor tariff customers and accelerate the expected payback period, however this approach would reduce transparency of the subsidy provided to participants and result in participants avoiding costs that have already been incurred on their behalf.

While payback periods are useful, they should be considered in tandem with the PCT and the expected Internal Rate of Return (IRR) over periods of 10 and 20 years. The use of IRR provides an alternative perspective on the financial performance of the customer's investment versus payback and PCT metrics, including the benefits received both before, and after, payback is expected to occur. Importantly, the IRR can be easily compared to other publicly available benchmarks such as expected returns of U.S. equities. The Commission should evaluate IRR, PCT and discounted and simple

---

[102] Ex. TRN-3, pages 88-90; Ex. TRN-1, pages 72-73, 76.

[103] Ex. TRN-3, pages 85-87; Ex. TRN-2, Attachment B, *see* UpfNOBWI, UpfWBWI, LNoBWI, LWBWI.

[104] Ex. TRN-3, page 25, *citing* Alternative Ratemaking Mechanisms for Distributed Energy Resources in California, E3, January 28, 2021, pages 27, 29; Ex. TRN-1, page 18 (The "E3 Payback" metric recognizes that ongoing operations and maintenance costs should be incorporated into the payback calculation. This can be accomplished by subtracting annual O&M costs from escalated annual bill savings or by adding discounted O&M costs to upfront costs. The latter is the approach E3 employed in its analysis. This metric is the net upfront investment plus discounted O&M costs divided by first year bill savings.)

payback metrics to determine the overall impact of a successor tariff on participating customers.

2. *Internal Rate of Return*

While the payback metric provides the number of years it takes for the customer's investment to be repaid, the Internal rate of return (IRR) is the rate of return that results in present value bill savings equal to present value costs, such that the net present value of the costs and benefits of the investment is zero. If the IRR is equal to or greater than the investor's opportunity cost of capital, the investment is economic.[105] While TURN's Model calculates this metric, no other party presents IRR results for their tariff proposals.

TURN urges the Commission to compare expected IRRs associated with investments in customer generation with expected returns for other investments commonly made by these same customers. TURN's rebuttal testimony points to recently developed forecasts of 10- and 20-year investment returns across a range of asset classes that are commonly included in individual retirement accounts and pensions.[106] These forecasts show return expectations for U.S. equities that range from 6.2% to 6.9% over a 10-year horizon and 7.1% to 7.6% over a 20-year horizon. Returns for bonds are forecast to be significantly lower with US corporate bonds ranging from 2.6% to 5.6% and US Treasuries ranging from 1.6% to 2.3%.[107] These return forecasts are pre-tax and do not include downward adjustments for the tax obligations assumed by the investor.[108]

The Commission should be skeptical of arguments that residential customers require a guarantee of much higher returns (IRRs) than investments in US equities in order to

[105] Ex. TRN-1, page 20, *citing* Brealey-Myers Principles of Corporate Finance 1996, page 14
[106] Ex. TRN-3, page 78; Ex. TRN-4, Attachment A (Horizon report)
[107] Ex. TRN-3, page 78; Ex. TRN-4, Attachment A (Horizon report), page 4, Exhibit 4.
[108] Even if the investment is placed in a retirement account, the entire proceeds are generally taxable as ordinary income at the time the funds are withdrawn.

induce investments in BTM resources.[109] By comparison to equity investments, proposed successor tariffs carry far lower risks for participating customers. In the context of the successor tariff proceeding, the risk associated with a customer's investment in behind-the-meter generation is limited to changes in compensation that may arise from changes in retail rate structure, retail rate level, and/or ACC values.[110] Certain successor tariff proposals reduce risks associated with compensation through measures such as fixing export compensation at current TOU rates or fixing avoided cost export values over a defined period of time. TURN's successor tariff allows for a 10-year lock in of export compensation that eliminates the risk that values will fluctuate unpredictably. Since the capital and operating costs of solar and storage investments are known to the customer at the time they invest, there is very little risk assumed by the customer. Finally, any up-front MTC incentive (as proposed by TURN) would be known to the customer at the time of investment, treated as a direct reduction to capital costs, and not be subject to any risk once the funds are received.

While stock market returns are generally taxable (as ordinary income or capital gains), the stream of payments to customers (including incentives) participating in a successor tariff do not create any additional tax liabilities. An apples-to-apples comparison of equity returns with successor tariff returns should account for the fact that net metering tariff returns are tax free.

TURN's modeling calculates IRRs under a variety of successor tariff scenarios. As shown in rebuttal testimony, the IRRs for tariffs that do not include any grid benefit charges and compensate exports based on retail rates are extremely generous. For non-CARE customers, tariff proposals by CalSSA, SEIA/VS and Sierra Club produce 10-year IRRs ranging from 12% to 20% for SCE and 18% to 22% for PG&E.[111] These values

---

[109] Retail investors regularly put their savings and retirement money into broad stock market investments such as mutual funds and Exchange Traded Funds based on the expectation of these forecasted returns.
[110] Ex. TRN-3, page 78.
[111] Ex. TRN-3, page 80.

average more than double the forecasted 10-year U.S. equities returns. These party proposals yield 20-year IRRs ranging from 16% to 24% for SCE and for PG&E from 18% to 26%.[112] These values are approximately triple the forecasted 20-year U.S. equities returns.

In contrast, the interim tariff proposed in the Joint Recommendations would yield 10 and 15 year IRRs in the range of 9-10%.[113] TURN's end-state successor tariff proposal yields IRRs that are low for non-CARE customers if there is no MTC and a full NUS charge.[114] If the Commission finds that a minimum target IRR should be achieved by non-CARE customers, it can make two key adjustments to TURN's tariff proposal – reducing the Nonbypassable Unavoidable and Shared (NUS) cost charge or adding an MTC incentive. It is also possible that forthcoming updates to the ACC values would yield higher export compensation values and thereby boost IRRs.

3. *Evaluation of additional contributions from legacy NEM customers*

A number of parties propose methods of assessing new fees on legacy NEM customers that are used to fund incentives for new solar adoption by low-income customers. Fees of this type are proposed by TURN, NRDC, and Cal Advocates.[115] The analysis of tariff proposals under the RIM test does not consider whether the source of funds used to subsidize new adoption comes from some, or all, customers. All customer funds used to support solar adoption are treated as a cost under the RIM.[116]

The Commission should recognize that any funds collected from legacy NEM customers reduce the cost burden for all remaining non-legacy customers. This fact is relevant to the consideration of successor tariffs that incorporate new fees on these

---

[112] Ex. TRN-3, page 80.
[113] Appendix A, Joint Recommendations, Section 6, Tables 1-6.
[114] Ex. TRN-1, pages 69, 71.
[115] Ex. NRD-1, page 21; Ex. PAO-1, 3-55 through 3-59
[116] Ex. TRN-1, page 74 (In a scenario where a portion of the MTC incentive is funded by Non-CARE NEM 1.0 and NEM 2.0 customers, the conventional RIM results would be unchanged).

legacy customers. While TURN's model does not separately model legacy and non-legacy customer RIM results, it does quantify the use of non-rate funds to support up-front incentives for CARE customer adoption and shows dramatic improvement in the RIM scores. The Commission should assign comparable value to mechanisms that limit the source of funding to legacy NEM customers rather than the general body of customers through quantifying legacy- and nonlegacy-customer specific RIM results. Although sourcing funds from outside utility rates is preferable, a mechanism that requires legacy NEM customers to make dedicated contributions towards these costs represents a second-best approach for purposes of protecting all non-participating customers from absorbing costs associated with the successor tariff and mitigating the cost shift associated with legacy customer adoptions.

4. *Evaluation of funds sourced outside retail rates*

The RIM test does not treat benefits received by participants as costs to all customers if the funding comes from sources outside of utility rates. Examples of these types of benefits include federal and state tax credits along with any rebates or incentives funded by general tax revenues or Cap-and-Trade funds that would not otherwise be credited to ratepayers.[117] TURN's successor tariff proposal is designed to accommodate the use of these non-rate funding sources to provide Market Transition Credit (MTC) incentive payments to non-CARE customers. TURN's model evaluates the impact of these external funding sources on the PCT and RIM results. This evaluation is intended to highlight the importance of harnessing other sources of funds to support DER adoption in order to protect non-participant customers from cost shifting.

TURN modeled the results of sourcing different fractions of MTC funding from non-rate sources. The following table shows results for all three IOUs assuming that CARE

[117] Ex. TRN-1, pages 19-20.

customers receive a sufficient MTC incentive to achieve a 10-year full discounted payback:[118]

TURN Proposal – CARE Customer Cost Effectiveness Results 25% of MTC from Non-Rate Sources			
Cost Effectiveness Metric	**PG&E**	**SCE**	**SDG&E**
RIM – base case	0.37	0.45	0.42
RIM – 25% external	0.44	0.53	0.52
RIM – 75% external	0.67	0.79	0.89

The improvements in the RIM score that result from the use of external funds are significant and demonstrate the value of such an approach. The Commission can recognize this value by authorizing tariff elements that can accommodate external funding to support new customer adoption. At a minimum, the Commission should endorse a process to identify external funding sources that could be used to reduce the cost burden on all ratepayers for any successor tariff that is otherwise not cost effective.

5. *Annual adoption targets*

Various parties argue that successor tariff proposals should be designed to achieve minimum annual adoption goals in order to provide ongoing support to the solar industry. CalSSA proposes that the Commission target 1,200 MW of consumer solar per year (across all customers) with a tariff designed to yield between 800-850 MW/year of residential deployment.[119] SEIA/VS proposes targets of 780 MW/year of residential deployment.[120] TURN does not agree that the Commission should adopt specific deployment targets and timetables as the standard for determining whether a successor tariff proposal is acceptable.

---

[118] Ex. TRN-1, page 75.
[119] Ex.CSA-1, page 7. RT Vol. 7, page 1122, Heavner. CalSSA assumes total deployments of 6360 MW between August 2022 and 2030. Depending upon whether the final step would be reached at the beginning, or end, of 2030, this schedule results in a deployment schedule of 800-850 MW/year.
[120] Ex. SVS-1, page 12.

None of these parties provide specific evidence that a particular annual adoption level for residential customers is needed to fulfill the direction provided in California Public Utilities Code §2827.1(b)(1) which was added to the Public Utilities Code in 2013.[121] In 2013, approximately 458 MW of new solar (296 MW of which was residential) was installed behind customer meters in the three IOU service territories.[122] Residential installations increased in subsequent years to as high as 869 MW in 2020 but averaged 685 MW between 2013 and 2020.[123] Regardless of this historical pace, the Commission should decline to adopt any particular annual target for purposes of determining whether a successor tariff proposal is likely to satisfy the applicable statutory requirements.

Moreover, the targets proposed by CalSSA and SEIA/VS were developed without any consideration of the various statutory requirements and other considerations included in the guiding principles adopted by the Commission in D.21-02-007. The only criteria guiding these parties, both of whom represent the solar industry, is the goal of achieving minimum annual MWs of ongoing deployment. To the extent that a successor tariff proposal does not satisfy the other requirements, including separate directives to ensure that the tariff is "based on the costs and benefits" of the generator and that the costs and benefits of the tariff are "approximately equal"[124], the Commission should not adopt it. The goal of achieving a specific rate of growth or sales in behind the meter installations should not take priority over the other explicitly enumerated considerations.

---

[121] AB 327 (Perea, 2013), *adding* Public Utilities Code §2827.1.
[122] Ex. TRN-3, page 27.
[123] Ex. TRN-3, page 27, footnote 49. Residential installations for the three IOUs were 296 MW (2013), 455 MW (2014), 767 MW (2015), 823 MW (2016), 669 MW (2017), 747 MW (2018), 859 MW (2019) and 869 MW (2020)
[124] Public Utilities Code §2827.1(b)(3), (b)(4).

In testimony, SEIA/VS urge the Commission to make determinations, in this proceeding, about the relative mix of large- and small-scale renewables that should be developed to satisfy broad resource planning objectives.[125] TURN does not believe that this proceeding is the appropriate forum for reaching any such conclusions. If the Commission wishes to configure a successor tariff to yield specific adoption targets, this determination should occur in the context of the Integrated Resource Planning (IRP) proceeding rather than on an *ad hoc* basis in the current docket. The Commission cannot reasonably determine the appropriate level of customer generation that should be deployed based on the evidence submitted in this proceeding.

Instead of picking a penetration target in this proceeding based on goals articulated by the rooftop solar industry, the Commission should defer to modeling in the IRP process that is capable of comparing both behind the meter and in front of the meter alternatives as part of a least-cost selection process and incorporates all relevant constraints. Any IRP modeling performed for this purpose should consider behind-the-meter (BTM) technologies as "candidate resources". This approach involves two steps.[126] First, the model should translate fixed costs for all resource alternatives into a levelized cost of energy designed to approximate pricing under a Power Purchase Agreement.

Second, the IRP process should expressly consider the additional costs of BTM resources to all customers under the successor tariff structure adopted in this proceeding.[127] This consideration must assess the total rate impacts of the successor tariff for a particular BTM resource based on the compensation structure in the adopted successor tariff (rather than the fixed resource cost that approximates PPA pricing). This two-pronged modeling effort should be able to balance the goals of least-cost resource development with the expected rate impacts for both in front of meter, and BTM,

---

125 Ex. SVS-1, page 7.
126 Ex. TRN-3, pages 27-28.
127 Ex. TRN-3, page 28.

resources. This effort should consider the differential rate impacts of additional procurement of large-scale renewable resources (the costs of which are collected from all customers) versus BTM resources (the costs of which are shifted to non-participating customers). If this two-pronged modeling effort can demonstrate the reasonableness of a certain target for BTM resources from both the IRP and customer bill impacts perspectives, the Commission can reasonably assess whether additional subsidies are appropriate to achieve the targets.

E. Relevance of adopted Guiding Principles to Methods of Evaluation

In D.21-02-007, the Commission adopted a series of guiding principles governing the consideration of successor tariff proposals.[128] In order to satisfy these principles, the Commission should rely upon the methods of analysis identified in the prior sections along with additional considerations described below.

1. *Principle #1 - Compliance with the requirements of Public Utilities Code §2827.1*

TURN's tariff proposal is fully consistent with the requirements of Public Utilities Code §2827.1 and responsive to the direction provided by the Legislature. Each of the relevant provisions of this code section are reviewed in the following sections.

> a. *§2827.1(b)(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.*

TURN believes the requirement that "customer-sited" renewable resources have the opportunity to "grow sustainably" may be satisfied if a successor tariff is found to be cost-effective for certain participants over a reasonably defined timeframe.[129] The adoption of TURN's proposed tariff would satisfy this requirement and allow continued growth in BTM solar installations. TURN's tariff proposal establishes a target

---

[128] D.21-02-007, Ordering Paragraph 1
[129] Ex. TRN-1, pages 31-32.

discounted payback period of 10 years for CARE customers that will enable these customers to make investments and/or other financial commitments to acquire new BTM systems.

The Commission has not previously adopted any quantitative methodology for determining whether a successor tariff would permit "sustainable" growth of renewable distributed generation. For example, D.21-02-007 declined to adopt a formal definition of "grow sustainably".[130] If the Commission finds in the future that a specific payback period or adoption goal is required to satisfy this requirement, it may adapt TURN's proposal to achieve that result through adjustments to the NUS charge and/or the MTC incentive. Such modifications could be designed to support adoption by both non-CARE and CARE customers.

Although TURN's proposal does not include new tariff options for residential customers located in disadvantaged communities (DACs), the Commission recently adopted several programs to increase access to solar for residents of disadvantaged communities located within the PG&E, SCE, and SDG&E service territories. These programs include the Solar on Multifamily Affordable Housing (SOMAH) program, the DAC-Single Family Solar Homes (DAC-SASH) program, the DAC-Green Tariff program, and the Community Solar Green Tariff program.[131] The SOMAH and DAC-SASH programs include up-front incentive funding to lower the costs to participating customers. TURN's tariff proposal could provide an additional upfront payment through the MTC, if needed, to ensure that any system serving a customer in a DAC achieves a discounted payback within 10 (or fewer) years.

Because TURN's successor tariff design places the entire subsidy amount in a one-time MTC, the Commission can easily recalibrate the MTC to ensure that any adopted

[130] D.21-02-007, page 11
[131] D.17-12-022, D.18-06-027

requirements relating to §2827.1(b)(1) are satisfied. The MTC should be seen as a flexible tool that can be used to promote adoption by specific customer subgroups and is adaptable to ongoing changes in system costs, financing assumptions, tax credits and avoided cost values.

b. §2827.1(b)(2) Establish terms of service and billing rules for eligible customer-generators.

TURN's tariff proposal would establish clear terms of service and billing rules for all NEM participants. Existing terms and rules under the current NEM 2.0 successor tariff that do not conflict with TURN's tariff proposal would remain unchanged. TURN's proposal therefore complies with this requirement.

c. §2827.1(b)(3) Ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.

The costs and benefits of the renewable electrical generation facility are those described in the TRC test. TURN's proposed tariff is based explicitly on these costs and benefits.[132] The benefits of the renewable electrical generation facility are based on avoided costs. Export compensation would be based on avoided costs and credit for self-consumption would be tied to the tariffed generation rate. This approach links credits under the tariff to the relevant benefits provided by the generating facility.

TURN's MTC is calculated based on a target payback period that explicitly accounts for the costs and benefits of the generating facility.[133] Changes in the cost for new facilities, including evolving tax benefits, would result in adjustments to the MTC amount. Changes to the forecasted benefits would also affect the MTC values. As a result, the costs and benefits of the facility are explicitly taken into account.

---

132 Ex. TRN-1, pages 45-51.
133 Ex. TRN-1, pages 51-56.

By comparison, the existing NEM 2.0 tariff sets export compensation based on retail rate components for the customer rather than the costs and benefits of the generation facility and provides credit for self-generation based on full retail rates. Parties that propose successor tariffs which continue to compensate customers based on retail rates similarly fail to demonstrate that their approach is "based" on either the costs or benefits of the generation. The Commission should therefore find that TURN's proposal represents far better alignment with this provision than either the existing NEM 2.0 tariff or the successor tariffs proposed by parties that continue to rely on retail rates as the method of measuring costs and benefits.

d. *§2827.1(b)(4) Ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.*

This provision requires the Commission to balance the RIM test components. TURN's tariff proposal is designed to link the total costs of the tariff (uncompensated program fees and lost rate revenues) to the total benefits provided to all customers and the electrical system (payments by NEM customers and avoided cost values from BTM resource production). TURN's tariff proposal would explicitly compensate NEM customers for the benefits provided to all customers and the electrical system using the most recently approved ACC values. The only portion of the compensation not tied to identified benefits is the MTC buydown, which is provided to ensure that specific customers achieve a target payback period.

TURN recognizes that the Commission wishes to assess the TRC results to determine adherence to this statutory requirement in addition to the RIM, PCT and PAC outcomes. However, the TRC results do not calculate the total costs and benefits of the tariff to all customers because they ignore the impact of the successor tariff on participant bill savings and the resulting the rate impacts on non-participants. As a result, for a given cost and generator characterization, the TRC values are constant across successor tariff options, making it impossible to use the TRC to compare tariffs that provide different levels of compensation or include features such as grid charges or up-front incentives.[134] Indeed it is impossible for the Commission to conclude that the TRC test justifies any particular tariff configuration.

TURN urges the Commission to focus on the RIM test for purposes of determining whether the costs and benefits of the tariff to all customers are equal. The RIM test compares the benefits of the tariff to all ratepayers with the costs of the tariff to all ratepayers. The RIM test is therefore the only cost test approach that accounts for the impact of NEM tariff design on all customers.

> e. *§2827.1(b)(5) Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements.*

TURN has not proposed any differential treatment of systems larger than 1 MW under its tariff and assumes in its results that all systems are sized to provide 100% of a customer's first year load.[135] TURN's proposal therefore satisfies this statutory requirement.

---

[134] The only notable impacts on TRC values occur if installed system costs or output profiles are different under different successor tariff options or if NEM customers are assumed to bear additional up-front system costs such as those tied to a second meter, interconnection or paying for estimated production calculations.

[135] Ex. TRN-1, page 22.

f. *§2827.1(b)(6) Establish a transition period during which eligible customer-generators taking service under a net energy metering tariff or contract prior to July 1, 2017, or until the electrical corporation reaches its net energy metering program limit pursuant to subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827, whichever is earlier, shall be eligible to continue service under the previously applicable net energy metering tariff for a length of time to be determined by the commission by March 31, 2014. Any rules adopted by the commission shall consider a reasonable expected payback period based on the year the customer initially took service under the tariff or contract authorized by Section 2827.*

Consistent with the requirements of §2827.1(b)(6), the Commission adopted a 20-year transition period for eligible NEM 1.0 customers in D.14-03-041. If the Commission concludes that any new charge or tariff modification for NEM 1.0 customers would infringe upon the adopted transition period, it can modify the original decision pursuant to Public Utilities Code §1708.[136] The Commission has previously held that it may modify a prior decision if new facts are brought to its attention, conditions have undergone a material change or the Commission proceeded on a basic misconception of law or fact.[137] TURN submits that these conditions are satisfied by the rapidly escalating cost shift resulting from NEM 1.0 installations, the overall decline in residential retail sales tied to NEM subscriptions, and accelerating increases in utility rates due to factors that could not have been known (or predicted) at the time that D.14-03-041 was adopted.[138] The Commission may therefore adopt modifications to D.14-03-041 that would affect the tariff requirements for NEM 1.0 customers.

[136] Cal. Pub. Util. Code §1708 (The commission may at any time, upon notice to the parties, and with opportunity to be heard as provided in the case of complaints, rescind, alter, or amend any order or decision made by it. Any order rescinding, altering, or amending a prior order or decision shall, when served upon the parties, have the same effect as an original order or decision.)
[137] D.97-04-049, 1997 Cal. PUC LEXIS 427, *17.
[138] To the extent that the Commission finds the 20-year transition period is no longer needed for non-CARE NEM 1.0 customers to achieve discounted payback, and the proposed surcharge would not infringe upon the achievement of payback over that period, it would be reasonable to modify D.14-03-041 to permit the imposition of a modest surcharge to cover a portion of the costs of the MTC for new low-income NEM customers.

TURN proposes that a portion of the costs of the MTC be collected from existing non-CARE NEM 1.0 and 2.0 customers through a new surcharge set at a monthly fixed amount per customer or based on $/kWh of NEM 1.0 and 2.0 customer usage.[139] Legacy CARE customers would be exempted from this charge. The total amount of funds to be collected from legacy NEM customers in each year would be a function of the incremental MTC costs and the percentage of these costs to be collected from existing NEM customers. Adding a modest surcharge to the monthly bills of non-CARE NEM 1.0 and NEM 2.0 customers would reduce the economic burden on all customers and should not have a material impact on the overall payback periods for NEM 1.0 and NEM 2.0 participants.

TURN also supports an accelerated transition period for NEM 1.0 customers to shift to the newly adopted successor tariff consistent with the Joint Recommendations. Pursuant to Section 5 of the Joint Recommendations, existing non-CARE NEM 1.0 customers would be required to switch to a new electrification rate tariff within five years after the date of their first interconnection and would be subject to a Grid Benefit Charge.[140] Eight years after initial interconnection, non-CARE NEM 1.0 customers would be required to fully transition to the successor tariff. These requirements differ from those adopted in D.14-03-041 and would therefore necessitate a modification to that decision in order to effectuate this provision of the Joint Recommendations.

g. *§2827.1(b)(7) The commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding. Any fixed charges for residential customer generators that differ from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electrical corporation. The commission shall ensure customer generators are provided electric service at rates that are just and reasonable.*

The NEM successor tariff reforms are being considered as part of a rulemaking that involves all of the large electrical corporations defined by §2827(b)(5) that were required

---

[139] Ex. TRN-1, page 55; Ex. TRN-3, pages 62-64.
[140] Joint Recommendations, Appendix A, Section 5.

to make NEM tariffs available to their customers and implemented the successor tariff adopted in D.16-01-044. To date, no party has suggested that the reforms proposed by TURN and other parties may not be considered in this proceeding.

2. *Principle #2 – A Successor Tariff Shall Ensure Equity Among Customers*

In D.21-02-007, the Commission declined to adopt a definition of "equity" in the context of this principle. TURN previously argued that achieving equity among customers involves the following:[141]

- Ensuring equal collection of unavoidable and nonbypassable charges from participating and non-participating customers.

- Ensuring all NEM customers pay a fair share for the grid services they use.

- Ensuring equal compensation for similar generation (i.e., similarly situated generation with the same output profile).

TURN's proposal ensures equity by compensating participating customers fairly for the value they provide to all other customers and ensuring that the choice to install BTM resources by one customer does not inequitably shift shared costs to non-participating customers. This outcome is achieved by linking generation exports to avoided costs, creating an MTC for CARE customers, and charging participants for their share of cost obligations that are unaffected by the decision to install BTM resources.

Moreover, TURN's proposal would treat customers equally regardless of their household income by providing tariffed bill savings based only on the value of the output from a BTM resource. Current NEM places a higher value on the output of a BTM resource serving a non-CARE customer as compared to a CARE customer. Most

[141] TURN opening comments on Proposed Guiding Principles for a Successor to the Net Energy Metering Tariff, R.20-08-020, December 4, 2020, page 4

proposals in this proceeding would perpetuate this inequity by compensating customers based on retail rates for self-consumption and exports. Crediting customers for either self-consumption or exports at rates that are tied to household income does not promote equity. Remedying the existing economic discrimination embedded in NEM rate design is necessary to enable the state to achieve its clean energy goals, including electrification of end uses and the accelerated adoption of behind the meter resources by CARE eligible households.

3. *Principle #3 - A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services*

TURN's tariff proposal does not specifically include new consumer protection elements. However, the Commission continues to consider consumer protection measures in R.14-07-002 separately from the development of successor tariffs. In D.20-08-001, the Commission adopted standardized inputs and assumptions for calculating electric utility bill savings from residential solar systems. These bill savings calculations rely on NEM 2.0 tariff design, assume escalation of utility rates over time and do not consider how changes to rate design, including the design of TOU periods and rate differentials across TOU periods, could affect a customer's bill savings. As a result, the standardized inputs fail to produce a calculation that offers meaningful certainty to a customer participating in NEM 2.0.

TURN's tariff proposal would enhance existing consumer protection measures by promoting transparency and increasing the certainty of expected payback for new solar investments in two respects. First, TURN's tariff would allow all successor tariff subscribers to opt for a 5- or 10- year export rate locked to the most recently adopted ACC hourly values for the entire period.[142] This option would provide certainty with respect to the compensation to be received for exports over the relevant timeframe and assist customers with making informed choices when considering purchase and leasing

[142] Ex. TRN-1, pages 45-48.

offers from vendors and installers. By contrast, NEM 2.0 customers have no reasonable method of locking in the value of export compensation over a similar timeframe.

Second, TURN's tariff proposal would provide an up-front MTC to CARE customers sufficient to achieve a 10-year payback and could be used to provide an up-front MTC to other customers, including non-CARE customers installing paired storage.[143] In combination with the opportunity for a 10-year export rate lock, this payment should give any customer receiving an MTC confidence in the economic value of their up-front investment. This certain up-front payment is more easily understandable to the customer than the long-term value associated with uncertain future retail rate escalation that is at the core of the tariff designs proposed by the solar parties.

4. *Principle #4 - A successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1*

This principle should be understood to require a successor tariff to compensate each technology according to the value it provides to the system. Offering identical compensation to resources that provide different value to the grid and all customers would be inconsistent with this principle. TURN's tariff proposal promotes technology neutrality because it ties export compensation to avoided costs based on the delivery profile of the eligible resource and each customer's individual load profile. In this way, each participating generator's compensation is more closely tied to the value it provides to the grid in a technology neutral way.

Although TURN's model only considers solar and paired storage resources, its successor tariff proposal is suitable for all eligible renewable generating technologies. Since export compensation would be based on either the ACC values or actual recorded market prices, any eligible renewable resource would be treated similarly with respect to the value of exported energy in a given hour. Further, any energy used to serve

[143] Ex. TRN-1, pages 51-56, Ex. TRN-3, pages 70-74.

onsite loads would result in equivalent bill savings for customers on the same rate schedule with similar loads and generation profiles, regardless of the type of eligible generating unit.

The MTC proposed by TURN can be adapted to provide the up-front subsidy needed to achieve a target payback period based on the ownership and operating costs of non-solar renewable generating resources. While TURN recommends using the same payback periods for all eligible technologies and MTC-eligible customer types, the Commission can adjust this parameter as a tool to support penetration within different categories of users.

5. ***Principle #5 -- A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeón), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18***

TURN's successor tariff proposal is coordinated with state energy policies and is aligned with the goal of producing a least-cost strategy for achieving California's ambitious decarbonization and clean energy objectives.

a. Affordability

The Commission should require that the development of a successor tariff is consistent with the goal of ensuring just and reasonable rates, and affordable service, to all customers. Earlier this year, the Commission released its annual report, pursuant to SB 695 (Kehoe, 2009) addressing cost and rate trends and actions to limit or reduce utility costs.[144] This report highlighted the importance of addressing the cost shift associated with NEM and other DER incentives. In an *En Banc* presentation to the Commission, Energy Division staff explained that existing NEM policy "contributes to rate increases"

[144] Ex. TRN-1, page 39, *citing* Utility costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1, California Public Utilities Commission, May 2021

because "IOUs pay more in NEM bill credits than they would pay elsewhere for the same amount of electricity and other electric grid benefits."[145]

The Staff report identifies the NEM cost shift to "lower-income non-participants" as one of the "three critical and overlapping regulatory fronts that must be actively managed" to address the widening gap between participants in BTM and DER programs and non-participants.[146] The evidence from both the Lookback study and other independent assessments demonstrates that the growing cost shift from existing NEM policy is neither sustainable nor scalable.[147] The Commission should consider affordability for all customers to be a key state policy objective to guide the consideration of successor tariff alternatives. Any successor tariff proposal that does not promote affordability for non-participants by significantly reducing the cost shift should not be adopted.

b. *Senate Bill 100 (DeLeón 2018)*

SB 100 (DeLeón, 2018) established the policy that eligible renewable energy resources and zero-carbon resources should supply 100% of retail sales of electricity to California end-use customers and state agencies by December 31, 2045. The provisions of the bill direct the Commission to "ensure that actions taken in furtherance of" the 100 percent objective "prevent unreasonable impacts to electricity, gas, and water customer rates and bills resulting from implementation of this section, taking into full consideration the economic and environmental costs and benefits of renewable energy and zero-carbon resources."[148] Consistent with this direction, the Commission should prioritize least-cost electric sector carbon reduction strategies that produce highest environmental value.

[145] Ex. TRN-1, page 39.
[146] Ex. TRN-1, page 39.
[147] Ex. TRN-1, page 39.
[148] Cal. Pub. Util. Code §454.53(b)(2).

The cost of carbon reductions under existing NEM tariffs is extremely high in comparison to other strategies that can support the achievement of the SB 100 targets. Absent major reforms to NEM tariffs, the increasing cost shifting associated with the deployment of substantial additional BTM resources will lead to unreasonable impacts to electricity rates that could impede the state's electrification efforts and that could be avoided without compromising progress towards a carbon-free grid. TURN's tariff would promote cost-effective deployment of new zero carbon NEM-eligible electric generation and limit subsidies to those needed to achieve specifically defined equity goals.

c. *Integrated Resource Planning Process*

The Integrated Resource Planning (IRP) Process was established pursuant to SB 350 (DeLeon, 2015). One of the program's statutory objectives is to "minimize impacts on ratepayers' bills."[149] The Integrated Resource Planning Process does not currently consider or quantify the costs of BTM resources in its planning assumptions. As noted by SEIA/VS witness Beach, the amount of customer-owned solar included in the IRP Reference System Plan is based solely on a forecast developed by the California Energy Commission that does not use any form of common resource valuation and is not a product of any cost-effectiveness analysis.[150]

Since future BTM deployment projections are a hard-wired input into the Reference System Plan, the IRP modeling does not consider BTM solar as a candidate resource subject to any type of cost-effectiveness analysis. As a result, the inclusion of BTM resource assumptions in the IRP modeling does not reflect any determination as to the relative costs in comparison to other resources. Moreover, the IRP modeling does not consider any rate or cost shifting impacts of NEM policy on BTM resource adoption.

---

[149] Cal. Pub. Util. Code §454.52(a)(1)(D).
[150] RT Vol. 8, page 1320, Beach.

TURN's tariff proposal would assist the IRP process by establishing up-front incentives to achieve specific payback periods for BTM resources. If TURN's approach is approved, the Commission could assess the incremental costs needed to deploy NEM resources in IRP modeling, with results used to inform the development of an optimal and least-cost resource portfolio. To the extent that the IRP modeling finds benefits from shorter BTM resource payback periods, this information could be used to modify the MTC structure. Absent this type of NEM reform, there is no clear way to identify BTM resource subsidies and compare them to alternative IRP-driven investments.

d. Title 24 Building Energy Efficiency Standards

The Title 24 standards require new residential buildings to include a solar PV system capable of serving a portion the building's load unless the home has shading or the builders opt for additional energy efficiency, storage or other options to reduce solar panel requirements. Although TURN does not propose to provide an up-front MTC for Title 24 new buildings, the Commission may choose to make such installations eligible if deemed necessary to support the cost-effectiveness of that program. If an MTC is authorized for these new residential buildings, the Commission should consider different payback assumptions to accommodate any material differences in the economic fundamentals of these installations such as a lower installation cost due to the efficiency of incorporating BTM resources into new construction.

There is no reason to conclude that changes in NEM tariffs conflict with the Title 24 requirements. In the process of considering the new rules, the California Energy Commission (CEC) found that the Title 24 solar mandate would remain cost effective under a range of future NEM tariff reform scenarios including a 'buy-all sell all' model that compensated all generation output at avoided cost.[151] By making any subsidies in the form of a MTC transparent, TURN's proposal would enable the CEC to evaluate the cost-effectiveness of Title 24 rules over time and determine whether additional

[151] Ex. CUE-3.

refinements to the policy are appropriate in light of the costs and benefits to new homeowners and the entire electrical system.

Although several parties argue that the Commission must ensure that a successor tariff is designed to satisfy the cost-effectiveness tests used by the Energy Commission under the Title 24 program, there is no statutory basis for this claim. Public Utilities Code §2827.1(b) directs the Commission to establish the successor tariff "notwithstanding any other law" and does not include any references to building codes or the Title 24 program as a relevant criteria.[152] Had the Legislature wished for the Commission to coordinate the development of the successor tariff to accomplish other state policy goals, or to coordinate with the Energy Commission, these requirements would have been included in the statutory text.

The Commission may support the New Solar Homes Mandate by authorizing a community solar alternative that provides a cost-effective option for home builders.[153] Pursuant to Section 10-115 of the 2019 Building standards, the Energy Commission may approve a community shared solar system as a compliance option to partially or totally meet the onsite solar generation that would otherwise be required by Section 150.1(b) of Title 24.[154] In February 2020, the Energy Commission approved a community solar option developed by the Sacramento Municipal Utility District (SMUD). The SMUD program permits builders and developers to enroll some or all new housing units into a Neighborhood SolarShares program that provides access to newly constructed solar facilities located within the SMUD service territory and guarantees bill savings to

[152] Cal. Pub. Util. Code §2827.1(b)(Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015…)[Emphasis added]
[153] TURN addresses the community solar proposal of CCSA in Section V.
[154] Ex. TRN-12, SMUD Neighborhood SolarShares Program application (revised), page 6, footnote 1.

participants.[155] The Energy Commission found this program to satisfy the requirements for the alternative compliance option included in the 2019 Building Standards.[156] In proposing this program, SMUD explained that it was designed to provide "homebuilders, developers and customers with a lower cost way of meeting the solar mandate while ensuring equitable rates for all of SMUD's customers".[157] More specifically, SMUD argued that its proposal was reasonable, in part, because it "does not result in cost shifts to non-participants."[158] The Commission should therefore recognize that the availability of a community solar alternative for new home construction can ensure that, regardless of the adopted successor tariff structure, the Title 24 New Solar Home Requirements will remain cost effective and need not be modified by the Energy Commission.

e. California Executive Order B-55-18

In signing Executive Order B-55-18, Governor Jerry Brown committed the state to achieve carbon neutrality no later than 2045. Although the CPUC is not expressly referenced, the Executive Order calls for all programs carried out to achieve carbon neutrality to "seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities."[159] TURN's tariff proposal places primary focus on the deployment of BTM resources by CARE customers and offers an approach to prioritizing deployment in Disadvantaged Communities by calibrating the MTC incentive to achieve a reasonable payback period for specific customer subgroups.

---

[155] Ex. TRN-12, SMUD Neighborhood SolarShares Program application (revised), California Energy Commission Resolution 20-0220-11.
[156] Ex. TRN-12, California Energy Commission Resolution 20-0220-11. Although CalSSA noted that it opposed the SMUD application, CalSSA witness Heavner acknowledged that the organization did not seek judicial review of the Energy Commission approval (RT Vol. 7, page 1152, Heavner).
[157] Ex. TRN-12, SMUD Neighborhood SolarShares Program application (revised), page 3.
[158] Ex. TRN-12, SMUD Neighborhood SolarShares Program application (revised), page 10.
[159] Executive Order B-55-18, Ordering Paragraph 5.

Moreover, TURN's proposal would slow the pace of future electricity rate hikes that are paid by nonparticipating low-income customers and lead to more affordable bills. Preserving affordable electricity service for all customers in low-income and disadvantaged communities is critical to achieving economic resiliency consistent with the Executive Order. Given the growing cost shift from higher-income NEM customers to lower-income customers, significant changes to NEM tariffs are necessary to further these objectives. Unlike current NEM policy, and many of the proposed successor tariffs, TURN's approach is directly responsive to the goal of promoting economic resiliency and improved air quality in low-income communities.

6. *Principle #6 -- A successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities*

TURN's proposal satisfies this principle through several of its core elements. As explained by TURN witness Chait during hearings, customers will be able to clearly understand the economic value proposition of TURN's proposed successor tariff.[160] Compensation would be the product of three elements – an up-front MTC incentive payment, a generation-based rate credit for production used for self-consumption, and Avoided Cost values for exports that can be locked in for a period of 10 years. These are all elements that can be easily understood by customers and can be explained by the same vendors that currently educate customers on existing NEM tariffs.

First, with respect to the MTC, the level of any MTC incentives would be known prior to the customer making a decision to invest in a new BTM system. By contrast, the level of compensation to be realized under the current NEM tariff is difficult, if not impossible, for prospective NEM customers to accurately assess when considering a new investment or contractual commitment. The economic value to existing NEM participants is heavily backloaded because the benefits are tied to future retail rate

[160] RT Vol. 9, page 1568, Chait.

design and rate escalation and there is no ability to lock in or hedge any of these benefits in advance.

Second, TURN's method of calculating responsibility for NUS costs would be tied to actual consumption by the individual customer. If a customer exports more of their energy (due to changing consumption patterns or vacation), the NUS charge will decline. The credit for onsite consumption is based on the tariffed generation rate that is easily understandable to vendors and customers alike.

Third, the value of exports would be based on ACC values that could be locked in for up to 10 years. These values would be known at the time the customer decides whether to opt for the lock in. As a result, the transparency of bill calculations and the basis for the compensation provided to a participating customer for the operation of their generating resource would be improved versus legacy NEM arrangements.

The uniformity of TURN's proposal across utilities is supported based on the use of a single approach to employing generation rates and avoided costs (ACC values) that takes into utility-specific avoided costs. By contrast, existing NEM tariffs provide far different levels of compensation to customers of each utility based solely on differences in retail rates across service territories. The current approach that ties NEM compensation to retail rates is not uniform and results in unequal value provided to customers based solely on the average retail rates charged by their incumbent utility.

7. *Principle #7 -- A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system*

TURN's proposal is designed to establish transparent incentives for customers to maximize the value of their BTM resources in a manner that also benefits all customers. TURN would set export compensation at the ACC values with the goal of introducing some portion of future payments based on day-ahead hourly CAISO market prices.

Both the ACC values and CAISO market prices are time-differentiated. As a result, TURN's tariff would motivate customers to maximize the economic value of their BTM resource production by aligning exports, to the maximum extent possible, with periods of higher hourly ACC and/or CAISO prices.

For example, customers would be motivated to undertake demand response, load shifting and conservation during peak hourly price periods to maximize the amount of production that can be exported and receive premium value. This behavior would benefit all customers by incentivizing or freeing incremental supply during hours of scarcity and peak pricing. Similarly, provided that retail rate price signals are aligned with avoided costs, providing a generation rate credit for production serving onsite load would motivate NEM customers to self-supply during periods when the TOU generation rate component is at its highest level, thereby realizing the greatest benefits to themselves and the system.

8. ***Principle #8 -- A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.***

TURN's tariff proposal would reduce cross-subsidization and mitigate any embedded incentives that motivate a participating customer to either remain with the incumbent utility or switch to alternative Load Serving Entities (LSEs). Because export credits would include both energy supply and non-energy supply components, participating customers taking service from non-IOU LSEs would receive export credits from two sources.[161]

For the ACC values not related to energy supply (transmission and distribution avoided costs paid by both bundled and departing load customers), the export credit would be provided by the IOU. For ACC values relating to energy supply, the export credit would be paid by the IOU only to its bundled customers. NEM customers served

[161] Ex. TRN-1, pages 44-45.

by non-IOU LSEs would receive energy supply export credits from their retail provider. This treatment preserves the obligation of each LSE to provide energy supply and generation services to their customers.

Because participating customers on bundled utility service would receive a generation rate credit for BTM production used for self-consumption, there would be no cross-subsidization from other rate components. Participating customers served by non-IOU LSEs are not charged an IOU generation rate and would therefore receive these credits from their retail provider. This approach permits Community Choice Aggregators (CCAs) and Direct Access (DA) providers to provide different, generation-related compensation than the IOUs. The choice to provide different compensation relating to energy supply value would be made entirely by the CCA or DA provider with any associated costs being borne entirely by their customers.

If up-front MTC incentives are funded through non-rate sources, they would be available to all eligible customers regardless of whether they take bundled service or are served by a CCA or DA provider. If MTC incentives are ratepayer funded, TURN proposes that the collection of any MTC costs in rates that are not sourced from legacy NEM customers would occur through the nonbypassable Public Purpose Program (PPP) charge applicable to both bundled and departing load customers, thereby ensuring that these costs are recovered in a competitively neutral manner.

V. ELEMENTS AND FEATURES OF A SUCCESSOR TARIFF

A. <u>Joint Recommendations</u>

TURN worked with a coalition of diverse parties in this proceeding to develop a set of Joint Recommendations relating to the design of the successor tariff. These parties include the Public Advocates Office, the Natural Resources Defense Council, the Coalition of California Utility Employees, the California Wind Energy Association, and the Independent Energy Producers Association. The Joint Recommendations cover essential policies, export compensation, a Grid Benefit Charge, equity provisions, transition of legacy NEM 1.0 and 2.0 customers, and an interim tariff designed to make immediate progress on reducing the NEM cost burden until the successor tariff can be implemented in full.[162]

The Joint Recommendations provide a framework for evaluating the successor tariff proposals made by various parties in this proceeding. The key elements of these recommendations involve the following:

- Ensuring that successor tariff customers are fairly compensated for the benefits of clean energy production tied to a quantification of avoided costs that does not unduly raise electric bills for non-participating customers.[163]

- Requiring successor tariff customers to pay a Grid Benefits Charge (GBC) that reflects their fair share of costs for transmission, distribution, non-bypassable charges, and any other shared system costs.[164]

- Transitioning existing NEM 1.0 and 2.0 non-California Alternate Rates for Energy (CARE) and non-Family Electric Rate Assistance (FERA) customers in a way that quickly decreases and eventually eliminates the NEM cost burden while ensuring a payback of the NEM customer's system cost over a reasonable timeframe.[165]

---

[162] The Joint Recommendations supported by TURN are attached to this brief as Appendix A. TURN endorses all the recommendations except for those contained in Section 4 (Equity Provisions).
[163] Joint Recommendations, Sections 1 and 2.
[164] Joint Recommendations, Sections 1 and 3.
[165] Joint Recommendations, Sections 1 and 5.

- Establishing an interim successor tariff for new residential NEM customers that can be quickly implemented and would apply prior to the finalization of key elements of the end-state successor tariff.[166]

The specific successor tariff proposal presented in TURN's opening brief is fully aligned with the Joint Recommendations. There are two sections of the Joint Recommendations that were not previously addressed in TURN's prepared testimony - the treatment of legacy NEM 1.0/2.0 customers and the development of an interim tariff that can be implemented prior to the finalization of an end-state successor tariff. These recommendations are reasonable, reflect a constructive effort of multiple parties to offer workable solutions, and are designed to balance the interests of participants and non-participating customers.

The proposal for moving existing NEM customers to the successor tariff includes both an accelerated timeline for the transition and incentives for NEM 2.0 legacy customers that voluntarily move to the new tariff between January 1, 2023 and December 13, 2027. Existing non-CARE NEM customers would be shifted to a suitable electrification rate schedule within five years of initial interconnection, a Grid Benefit Charge would be applied five years after initial interconnection (or as soon as practicable), and full transition to the end-state successor tariff should be complete eight years after initial interconnection.[167] As shown in the Joint Recommendations, these proposals could reduce the existing cost shift by as much as 76% if fully implemented.[168]

TURN believes that an accelerated timeline for a transition is justified by the need to balance the interests of participants and non-participants and that the specific mechanisms proposed in the Joint Recommendations constitute an appropriate glidepath that should allow all legacy customers to achieve payback of their initial

[166] Joint Recommendations, Sections 1 and 6.
[167] Appendix A, Joint Recommendations, Section 5.
[168] Appendix A, Joint Recommendations, Section 5.

investments within a reasonable timeframe. TURN's modeling of existing NEM 2.0 tariffs found that fully discounted payback periods of 6 years for non-CARE customers of PG&E and SDG&E and 8 years for SCE non-CARE customers.[169] Given these rapid paybacks, the transition to the new end-state successor tariff starting 8 years after initial interconnection would allow these customers to realize full paybacks before transitioning to the end-state tariff and receive ongoing bill savings and investment returns for the remainder of their system life. This result is fair to legacy NEM customers.

The separate proposal for an interim transition tariff is based on the desire for a glidepath to the successor tariff and a recognition that the implementation timeline for an end-state successor tariff could involve years of work (in particular to make the needed changes to the IOU billing systems). To ensure that a reformed tariff is available shortly after the issuance of a final decision in this proceeding, TURN recommends that the Commission require new residential NEM customers to enroll in an interim successor tariff within 90 days of a final decision in this proceeding that would have the following features:

- Use electrification rate schedules to more accurately align pricing with marginal costs.[170]

- Set export compensation for non-CARE customers at a defined percentage of current retail rates (under the relevant electrification tariff) with no escalation over time. The resulting export rate should be sufficient to achieve a full discounted payback of no longer than 15 years for SCE and PG&E and no longer

[169] Ex. TRN-1, page 76.
[170] Appendix A, Joint Recommendations, Section 6. For SDG&E, the appropriate rate would be an EV rate (EV-TOU-5) with a modified basic charge of $1.50/day for non-CARE customers and $0.40/day for CARE customers). If SDG&E receives approval for an electrification tariff, the new tariff could be substituted for EV-TOU-5.

than 10 years for SDG&E.[171] The use of a shorter payback period for SDG&E is driven almost entirely by the significantly higher retail rates applicable to SDG&E customers that make a longer payback difficult to realize under the proposed interim tariff structure.[172]

• Allow CARE customers to receive export compensation based on current undiscounted non-CARE retail rates net of the NEM 2.0 nonbypassable charges and PCIA.[173]

• Export rates for each IOU would be fixed (by TOU period) and not escalate over time regardless of overall increases in retail rates.

• Allow customers to remain on the interim tariff structure for 15 years (for PG&E and SCE) and 10 years (for SDG&E) before requiring a transition to the end-state successor tariff for each IOU.

• Sunset eligibility for new customer enrollments in the interim tariff no later than January 1, 2024 when the end-state successor tariff should be ready.

The Joint Recommendations contain a full set of results for the specific interim tariffs that would apply to each IOU. These results show the percentage reductions to Non-CARE export weighted rates, the resulting export compensation for a typical solar or solar+storage profile, TRC/RIM/PCT values over various timeframes (20, 15 and 10 years), the full discounted and simple payback periods, Internal Rates of Return and

---

[171] Appendix A, Joint Recommendations, Section 6, Tables 1-6. The Joint Recommendations propose export rates that represent a 34% reduction from the SCE retail rate (net of NEM 2.0 nonbypassable charges plus PCIA), a 44.5% reduction from the PG&E retail rate (net of NEM 2.0 nonbypassable charges plus PCIA), and an 85% reduction from the SDG&E retail rate (net of NEM 2.0 nonbypassable charges plus PCIA).

[172] Even setting export compensation at zero would allow SDG&E non-CARE customers to receive a payback in well under 15 years.

[173] Appendix A, Joint Recommendations, Section 6, Tables 1-6.

First Year Cost shift.[174] These results were produced using TURN's cost effectiveness model that was entered into the evidentiary record of the proceeding.[175]

TURN believes that this interim tariff is appropriate because it can be implemented quickly, is closely related to the current NEM structure, would reduce the long-term cost shift (as evidenced by the modeled RIM scores), and allows for both reasonable payback periods and IRRs (which range from 9-10% for non-CARE customers).[176] For SCE and PG&E customers, the interim tariff is expected to yield fully discounted payback periods of 13-15 years and simple payback periods of 8-9 years. For SDG&E customers, the interim tariff is expected to yield fully discounted payback periods of 10 years and simple payback periods of 7.5 years.[177] Moreover, these tariffs attempt to level the playing field between lower and higher income ratepayers by boosting export compensation for CARE customers (relative to non-CARE customers) to achieve payback periods that are comparable for both customer types.[178] Finally, the interim tariff would provide sufficient motivation for customers to install paired energy storage given the more robust compensation for systems that can export during higher priced TOU periods.[179]

The mechanics of the interim tariff, along with the steps needed to calculate the defined percentage reductions to the 2022 net electrification rates, are clearly described in the Joint Recommendations. Because the interim tariff requires only modest changes to

---

[174] Appendix A, Joint Recommendations, Section 6, Tables 1-6.
[175] Ex. TRN-5.
[176] Appendix A, Joint Recommendations, Section 6, Tables 1-6.
[177] Appendix A, Joint Recommendations, Section 6.
[178] Appendix A, Joint Recommendations, Section 6, Tables 1-6. The discounted payback periods for CARE and Non-CARE customers would be identical for SDG&E (10 years) and comparable for PG&E (14 vs. 13 years) and SCE (15 vs. 13 years).
[179] Appendix A, Joint Recommendations, Section 6, Tables 2, 4, 6. The expected export compensation for paired storage is significantly higher than for stand-alone storage. For SCE, the non-CARE difference is 4.3 cents/kWh (12.7 vs. 8.4 cents). For PG&E, the non-CARE difference is 5 cents/kWh (12.9 cents vs. 7.9 cents). For SDG&E, the difference is smaller (0.6 cents) but the payback period for paired storage would be equivalent (10 years) to a stand-alone solar system.

existing tariffs, TURN believes it can be put into place quickly and serve as a bridge until work on the end-state successor tariff is complete. TURN does not support the interim approach being approved as an end-state successor tariff because the structure fails to adequately prevent cost shifting, does not expressly link export compensation to avoided costs, and fails to incorporate an MTC that can spur adoption by CARE customers. But the interim tariff would constitute an incremental step in the right direction, ensure that BTM investments deliver sufficient benefits to participants, and sunset any excessive compensation after expected payback has been achieved. The

For these reasons, TURN urges the Commission to give serious consideration to the Joint Recommendations and adopt the transition program for legacy NEM customers (Section 5) along with the interim tariff for new customers (Section 6) that would apply until more comprehensive reforms can be implemented and incorporated into the IOU billing systems.

B. TURN successor tariff description

1. Export Compensation

TURN's successor tariff proposal would provide export compensation based on forecasted and, to the extent possible, actual avoided cost values.[180] This approach is designed to perfectly align this element of the successor tariff with the benefits provided by the customer generation. The primary method of determining avoided cost values should be the Avoided Cost Calculator (ACC). These values have been developed by the Commission through a rigorous and transparent process expressly designed to determine the value of DERs to the grid and all customers.[181] Given the clear direction provided by the Commission in past proceedings and the current docket, there is no other valid method of determining the reasonableness of export compensation.

---

[180] Ex. TRN-1, pages 45-47.

[181] D.16-06-007, D.19-05-019.

The ACC represents the Commission's best estimate of avoided costs, including those associated with deferred Transmission and Distribution investments, as part of a common valuation framework. To the extent that some parties in this proceeding believe that the ACC fails to adequately incorporate some elements of avoided costs, those concerns should be raised in the appropriate ACC update process. If additional or enhanced values are ultimately incorporated into the ACC, TURN's proposal would provide these values to successor tariff customers through export compensation. This approach ensures that any adjustments to avoided cost values occur within the ACC update process and apply equally to the valuation of all distributed energy resources.

Under TURN's proposal, export credits would be based on Avoided Cost Calculator (ACC) hourly values applicable to the present year based on the most recent ACC update, with energy, losses and ancillary services values replaced with CAISO day-ahead market-based values when feasible. Consistent with the Joint Recommendations, TURN also supports the averaging of the two most recent ACC updates for purposes of establishing hourly compensation values.[182] To ease any implementation challenges, TURN would endorse (as an initial measure) the aggregation of ACC values into Time of Use (TOU) periods that apply the same values across existing TOU periods varied by month or season.[183] To avoid excessive complexity relating to locational value, TURN proposes to use a single average hourly value in each IOU service territory for components that vary by climate zone in the ACC model such as avoided distribution costs.[184]

---

[182] Appendix A, Joint Recommendations, Section 2 (Export Compensation).

[183] RT Vol. 10, pages 1658-1659, Chait. ("In the near term, it would make sense for avoided cost to be summed into a – TOU period prices that would reflect the TOU periods of the underlying rates, and as the IOUs develop the capabilities to implement more granular pricing, I think that more granular avoided cost compensation could be implemented.")

[184] RT Vol. 10, page 1661, Chait (ACC model calculates these values by Climate Zone for each IOU and could be averaged).

TURN proposes to divide the ACC values into two categories. For non-energy related components (GHG adder, GHG portfolio rebalancing, methane leakage, generation capacity, transmission, and distribution), TURN believes that values should be derived from the most recent ACC (or an average of the two most recent).[185] For energy supply costs (energy, GHG Cap and Trade, ancillary services, and losses), TURN proposes to use day-ahead hourly wholesale market prices using recorded California Independent System Operator (CAISO) market supply data.[186] This approach would ensure that bill credits for exported electricity are better aligned with actual wholesale market costs rather than historically generated ACC price forecasts.[187] TURN recognizes that the use of actual hourly wholesale prices may not be immediately implementable but expects that the IOUs could provide this billing capability by the middle of the decade when real-time pilot programs in place for eligible customers.[188] TURN therefore supports delaying the incorporation of actual wholesale market costs into export compensation for several years until this capability is available.

Although TURN supports combining hourly ACC values into TOU periods for purposes of initial implementation, these values should ultimately be disaggregated into hourly prices as part of an end-state tariff. Export quantities would be determined based on instantaneous netting summed over each hour (as part of an end-state tariff),

---

185 Ex. TRN-1, pages 45-46.

186 Ex. TRN-1, pages 45-46. CAISO market prices would include the Cap & Trade adder, ancillary services costs, and losses. Set percentages can be employed to estimate losses and ancillary services costs based on day-ahead market prices, consistent with ACC values.

187 Ex. TRN-1, page 46; Ex. TRN-3, page 40. The use of actual market prices would provide premium compensation to participating customers for exports during hours when real-world market prices are high. During such periods, day-ahead wholesale market price information, including CAISO flex alert communications, would motivate participants to engage in load shifting, demand response and conservation measures in addition to those signaled in retail rates in order to realize higher export credits. This type of customer response would be useful when system conditions are stressed and additional supply is needed to support the entire grid. Providing incentives for additional exports during these peak conditions would benefit all customers and help to alleviate overall scarcity conditions.

188 RT Vol. 9, pages 1566, 1569, Chait; Ex. TRN-3, page 40.

or based on hourly netting if the IOUs cannot easily implement instantaneous netting, and aggregated into TOU periods (for each day) over the initial years of the tariff.[189]

TURN also proposes that new participating customers be permitted once, at the time of their initial subscription, to opt into fixed export rates covering all avoided cost values over defined terms of 5 or 10 years.[190] This proposal is designed to reduce the risk of uncertain export compensation over a reasonable time frame. The applicable export rates would be fixed based on the most recently updated ACC model values (or the two most recent ACC updates) for all hours over the defined term.[191] As noted in TURN's testimony, this approach would not apply either a single rate or first year values but rather would rely on the ACC values forecast for the entire set of hours over the defined term.[192]

The lock-in option should be limited to new participants to provide greater certainty with respect to the value of exports over some or all of the anticipated payback period. When combined with an MTC, the lock-in provides a very high level of certainty about participant economics over the defined term. The value of this approach is recognized by other parties. During cross examination, SEIA/VS witness Beach noted the benefits of providing customers with a fixed export compensation rate for 10 years in Arizona, noting that "it certainly helps them to calculate the economics for the first 10 years."[193] TURN believes that this certainty would be valuable to participants and is acceptable from the perspective of nonparticipants so long as the lock-in does not extend beyond

[189] RT Vol. 9, page 1566, Chait.
[190] In rebuttal testimony, SEIA/VS incorrectly claims that any certainty would be undermined by also relying on hourly CAISO energy market prices (Ex. SVS-4, page 41). In fact, TURN's proposal would allow all ACC values to be locked in for up to 10 years, including those related to wholesale energy prices.
[191] This does not mean that a single rate would be applied, but rather that the ACC values forecast for the entire set of hours over the defined term would be locked in. Exports over the defined term would receive the appropriate hourly (or TOU) value in each year.
[192] Ex. TRN-1, page 47, footnote 74.
[193] RT Vol 8, page 1289, Beach.

10 years. ACC values extending beyond that time horizon are increasingly speculative and less reliable.[194]

Export credits would be applied to customer bills on a monthly basis. Any surplus credit balances (in excess of charges owed by the customer) on the monthly bill could be carried forward and applied to a future bill for a period of up to 12 months. At the end of 12 months, any remaining balance would be adjusted based on the applicable net surplus compensation methodology required by Public Utilities Code §2827(h)(5).[195] This approach is consistent with existing law, permits the rollover of excess balances for a defined period of time and minimizes the potential for cost shifting.

For customers served by CCAs and Direct Access (DA) Providers, TURN recommends that the IOUs provide an export credit equal to the components of the ACC related to transmission and delivery services provided by the IOU - benefits that are expected to reduce IOU tariffs charged to both bundled and departing load customers. All generation-related components included in the ACC should be compensated by the CCA or DA Provider serving the individual customer based on values that they determine.[196]

TURN submits that this export compensation approach is straight-forward, aligns with the Commission's existing approach to valuing distributed energy resources, is transparent for participants, and would ensure that export compensation is only provided for demonstrated and approved avoided cost values that reflect benefits to the electricity grid and all customers. It is therefore fully consistent with the relevant guiding principles and statutory requirements.

---

[194] Ex. TRN-3, pages 37, 40.

[195] The methodology used to calculate Net Surplus compensation was adopted in D.11-06-016.

[196] Since the Commission does not regulate CCA or DA retail rates, the export compensation offered by these retail providers for generation-related values falls outside the scope of this proceeding.

2. *Import rates*

Under TURN's end-state tariff, participants with stand-alone solar would be permitted to take service under any Time of Use (TOU) tariffs for which they are eligible. Prior to the implementation of the end-state tariff, TURN proposes that all new successor tariff customers should be required to enroll in an interim rate that requires participation in an electrification tariff.[197] Once the end-state tariff has been implemented, TURN would allow new participants to choose any available TOU rate option.[198] For customers with paired storage, TURN would require participation in an electrification tariff that has significantly larger peak-to-off peak rate differentials and may include fixed charges. This requirement is needed to provide a strong price signal for utilization of storage that aligns with system needs.

TURN's ambivalence about requiring all successor tariff customers to participate in an electrification rate is based on concerns over the disproportionately adverse impacts on smaller customers that are currently served on rates that include baseline quantities.[199] Because participation in an electrification rate could produce marginal reductions in the overall cost shift (relative to current NEM 2.0), TURN believes that it is appropriate to include in an interim tariff that modifies export compensation but does not include other grid charges or other mechanisms to recover Nonbypassable, Unavoidable and Shared costs.[200]

Allowing NEM participants to take advantage of any available TOU rate as part of an end-state successor tariff would support customer choice and enable the uptake of rate

---

[197] This proposal is included in the Joint Recommendations of the Independent Parties. The transition rate would not include any new Grid Benefits Charge or a Market Transition Credit.
[198] The "end state" tariff criteria would be satisfied when the successor tariff includes both a Grid Benefits Charge and a Market Transition Credit for eligible customers.
[199] Ex. TRN-3, page 42. TURN's modeling results show that, under TURN's successor tariff proposal, small customers taking service on a baseline rate structure prior to successor tariff participation may experience lower 20-year bill savings on a successor tariff electrification rate than on a successor tariff with a baseline structure.
[200] Ex. TRN-3, page 42.

options. Some customers with material consumption occurring during peak periods that proves difficult to shift may prefer to avoid the extremely high on-peak rates that result from some of the more extreme electrification tariffs.[201] TURN's tariff proposal provides appropriate flexibility for customers to choose their preferred tariff based on their preferences and rely on behind the meter generation.

3. *Self-consumption charge for Nonbypassable, Unavoidable and Shared (NUS) costs*

TURN proposes a separate monthly charge to recover Nonbypassable, Unavoidable and Shared (NUS) costs associated with self-consumption of output from customer BTM generation.[202] This charge is designed to recover non-generation costs that would be paid by the participating customer but for production from the BTM resource. The NUS charge would be dynamically calculated based on either the actual or estimated self-consumption attributable to BTM generation. The total charge for a participating customer would vary by month because the calculated cost responsibility is directly correlated with the amount of actual usage supplied by BTM resources and not exported to the grid.[203] TURN's proposal should therefore not be characterized as either a fixed monthly charge or a solar capacity charge.[204]

The customer's total NUS cost obligation would be calculated by multiplying the NUS charge by the number of kilowatt-hours of customer consumption supplied by BTM production during the billing cycle that is not exported. The key calculation is as follows:

---

[201] Ex. TRN-3, page 43.
[202] Ex. TRN-1, pages 48-51.
[203] In a billing cycle when the customer records *de minimus* self-consumption, the monthly NUS charge would also be *de minimus*.
[204] Ex. TRN-3, page 48. TURN's NUS is not denominated in $ per kW of installed capacity but is instead assessed on a cents/kWh basis, relies on existing charges currently collected from all customers, and is tied to actual or estimated self-consumption quantities in each monthly billing cycle.

Total monthly NUS cost =
kWh of customer self-consumption supplied by BTM resources
x total NUS rate per kWh

TURN's model assumes the following NUS costs are, or would be, characterized as either nonbypassable or unavoidable/shared costs:[205]

Cost category	**Nonbypassable (NBC) or Unavoidable/Shared (U/S)**
Distribution	U/S
Transmission	U/S
Reliability Services (RS)	NBC
New System Generation Costs (NSGC)	NBC
Public Purpose Programs (PPP)	NBC
Wildfire Fund Charge[206]	NBC
IOU securitization for costs relating to wildfires or other undercollections	NBC
Competition Transition Charge (CTC)	NBC
Power Charge Indifference Adjustment (PCIA)	NBC
Nuclear Decommissioning	NBC
Energy Cost Recovery Account (PG&E)	NBC
PUC Reimbursement Surcharge	NBC

If the Commission agrees that all of these cost components should be characterized as NUS costs, the successor tariff customer's self-consumption would be credited for the generation rate which comprises the remaining portion of the applicable import tariff.[207] If the Commission finds that a smaller portion of non-generation charges should be classified as NUS costs, a modified version of TURN's approach can be adopted that limits NUS costs to a subset of the above cost categories. TURN's modeling includes

[205] Ex. TRN-1, page 49.
[206] This rate component was previously used to collect DWR bond costs.
[207] By the time a new successor tariff is in place, the bundled customer generation rate will no longer include the above-market costs associated with utility generation resources. Pursuant to D.20-03-019, all three IOUs are required to remove PCIA costs from bundled generation rates and collect PCIA costs separately from bundled customers. Consistent with the proposed method of collecting the PCIA from all bundled customers, TURN proposes that successor tariff customers taking bundled utility service are assessed non-vintaged PCIA obligations.

scenarios with partial NUS collection to illustrate the impacts on RIM, PCT and payback periods.[208] For example, a modified NUS that does not include transmission charges (for SCE Non-CARE customers) improves the PCT results by 0.12 and reduces the RIM results by 0.11.[209] As explained by TURN witness Chait during hearings, the NUS proposal can be adapted to limit the scope of applicable rate components to improve participant economics and promote shorter payback periods.[210]

While TURN recognizes that the Commission may wish to collect a less than full share of transmission and distribution costs associated with self-consumption, the Commission should classify all NBCs (as shown above) as NUS costs rather than retaining the limited scope of such charges included in the NEM 2.0 tariff. In particular, the Commission should ensure that both the PCIA and New System Generation Costs and Local Generation Charge (NSGC/LGC charges) for new generation are included in the list of NBCs since these reflect sunk costs previously incurred to serve all customers. Moreover, the Commission should ensure that any new charges relating to IOU securitizations (primarily tied to wildfire costs) are included in the NBCs assigned for full collection from successor tariff customers.[211]

With respect to Transmission and Distribution costs, the Commission should recognize that these rate components collect many costs that are not affected by a customer's decision to invest in self-generation.[212] During hearings, SEIA/VS witness Beach

[208] Ex. TRN-1, page 72; Ex. TRN-3, pages 85-90; Ex. TRN-3, page 48 (TURN presented separate results that include and exclude the PCIA from the NUS charge. TURN calculates that the present value (7.68%) of NUS charges proposed by TURN equals $5,560 (if NUS excludes PCIA) or $6,741 (if NUS includes PCIA) over the likely 20-year term of the successor tariff for the E3 SCE Non-CARE customer)
[209] Ex. TRN-1, page 72.
[210] RT Vol. 9, pages 1557-1558, Chait.
[211] For example, the Commission approved securitization charges for PG&E in D.21-04-030 and D.21-06-030.
[212] Ex. TRN-1, page 50, footnote 82. Costs not affected by a customer's consumption or peak demand would include wildfire mitigation expenditures (including vegetation management and wildfire liability insurance), the Catastrophic Events Memorandum Accounts (CEMA) and Hazardous Substance Mechanism (HSM) balancing accounts, transportation electrification

admitted that no costs of grid hardening for existing transmission and distribution facilities are avoided through customer adoption of solar or storage.[213] Similarly, CalSSA witness Heavner agreed that utility proposals to underground large portions of distribution lines in high fire threat districts would not be affected by the decision of any individual customers to install behind the meter solar.[214] This possibility is not merely hypothetical given PG&E's recent announcement to seek Commission approval to underground 10,000 miles of power lines in high fire threat districts, a project that could require $40 billion in utility capital expenditures.[215] To the extent that such costs would be collected in distribution rates, CalSSA witness Heavner agreed that a customer installing solar would not cause a reduction in overall utility expenditures but would pay a smaller share of these costs than a customer without solar.[216]

Unless costs that are unaffected by self-generation are collected from successor tariff participants, the revenue shortfalls resulting from BTM generation output consumed onsite (which would otherwise have been served through imports) will be recovered through higher overall rates borne by all ratepayers. This result is manifestly unfair to the general body of ratepayers who are already suffering from unaffordable rates and would be forced to absorb additional costs based solely on the decision of a subset of customers to self-generate.

CalSSA opposes TURN's proposal and argues that it would be unreasonable to assign any form of Grid Benefit Charge on solar customers because it requires them to pay for "services they do not receive."[217] Yet under cross-examination, CalSSA witness Heavner agreed that is it reasonable for a residential customer without onsite generation to be

---

programs, and customer access costs (including hookup costs and revenue cycle services). These costs are primarily collected in Distribution rates although some costs (including CEMA/HSM) may be included in Transmission rates.

[213] RT Vol. 8, page 1352, Beach.

[214] RT Vol. 7, pages 1132-1133, Heavner.

[215] Ex. TRN-7.

[216] RT Vol. 7, pages 1131-1132, Heavner.

[217] Ex. CSA-2, page 55.

charged for the costs of various programs that may not directly benefit them, including low-income discount programs, electric vehicles, and wildfire mitigation.[218] While it is well accepted that customers should pay to support programs that provide these general benefits to society, even if they are not participants in the programs, CalSSA asks the Commission to carve out special treatment for self-generation customers by exempting them from making a full contribution towards programs that provide broad benefits or promote the general welfare. The Commission should decline to provide this exemption and clarify the importance of shared contributions to shared obligations.

Despite admissions by the solar parties that many utility costs are not avoided through customer generation, none offer any proposed method for fairly collecting new costs of these types from all customers. Instead, these parties propose tariff structures that would specifically permit customers with onsite generation to reduce their share of the cost obligation.[219] Even if such costs were to be classified as nonbypassable charges, CalSSA argues that successor tariff customers should be credited for these components of rates as part of export compensation.[220] The Commission should decline to embrace this unreasonable outcome.

For calculating the portion of customer self-consumption supplied by BTM resources, TURN proposes allowing the NEM customer to choose between two alternative approaches.[221] Under the first approach, the customer may install a second meter on the BTM resource and provide production data to their utility.[222] The exported portion of

---

[218] RT Vol. 7, pages 1166-1168, Heavner.
[219] RT Vol. 7, page 1133, Heavner. (“there is no extra fee that would be assessed to solar adopters.”)
[220] RT Vol. 7, page 1136, Heavner (“It is not our proposal to add any non-bypassable charges to the group of non-bypassable charges that is used to calculate the NEM export rate.”)
[221] Ex. TRN-1, pages 50-51. TURN’s modeling assumes that the customer is responsible for paying either a $900 second meter cost or a $100 upfront cost for estimating generation.
[222] RT Vol. 9, pages 1526-27, Chait. The meter would either need to be revenue grade or provide comparable accuracy with respect to monitoring and tracking total production. As explained by TURN witness Chait, the meter could be installed by either the customer or the utility; Ex. TRN-3, page 51. In response to concerns raised by CalSSA in testimony, TURN recognizes the

BTM generation (as tracked by the primary customer meter) would be deducted from total generation to calculate the remaining amounts used to serve onsite loads. Under the second approach, hourly and monthly production from the BTM resource would be estimated based on engineering estimates that account for system capacity, location, orientation and any other relevant factors. Metered exports would be deducted from this total amount to determine the number of kilowatt-hours used for self-consumption. TURN suggests that customers with paired storage be required to implement the second meter alternative due to the complexity of estimating storage dispatch. All customer-specific data collected from a second meter should be subject to the same privacy and confidentiality standards that apply to all customer-specific usage and billing data.[223]

In rebuttal testimony, SEIA/VS oppose the NUS proposal based (in part) on the concern that it would be unreasonable to expect that solar customers could "estimate what their own BTM usage will be" for purposes of assessing the impact of an NUS charge.[224] Yet during cross-examination, SEIA/VS witness Beach acknowledged that "it's relatively easy" to estimate "how much of the power's going to be used on-site versus exported."[225] Mr. Beach also agreed that this type of analysis would typically be performed by a solar installer when developing a proposal for consideration by a customer to be served under the existing NEM tariff.[226] The SEIA/VS critique also ignores the fact that forecasting the fraction of power to be exported by customer generation is a key feature of all party proposals in this proceeding. Because the solar parties propose declining export rates, the gap between import pricing and export

---

importance of streamlining the interconnection process and, to that end, is not opposed to allowing a solar vendor to install the second meter, provided it meets utility requirements for revenue billing.

[223] Ex. TRN-3, page 51. Contrary to the claims made in CalSSA's direct testimony (Ex. CSA-1, page 103), TURN is not proposing that any private customer billing data be made available to the state of California or the federal government.

[224] Ex. SVS-3, page 46.

[225] RT Vol. 8, page 1313, Beach

[226] RT Vol. 8, page 1314, Beach

pricing would be expected to grow over time.[227] This gap means that the value of exports will be significantly lower than the value of self-consumption. Knowing the fraction of output to be used for either purpose will become important to any assessment of cost-effectiveness for an individual customer. This is even more important under the solar party proposals given the larger gap between self-consumption and export rates than exists under the TURN successor tariff proposal.

The Commission has previously ordered specific nonbypassable costs to be assessed on the portion of certain departing customer loads served by onsite generation.[228] Pursuant to that requirement, all three IOUs have rate schedules that collect several nonbypassable charges from eligible departing load customers based on the metered or estimated production from onsite generation used to serve the customer's load.[229] The calculation of such cost responsibility includes metering or estimating production from onsite generation. Tracking of different types of behind-the-meter customer consumption for utility billing purposes has also been implemented in other states.[230]

The Commission should recognize that TURN's approach to the collection of NUS costs carefully calibrates cost responsibility with actual customer usage provided by BTM generation over the course of each month. As compared to a lump-sum fixed charge, or a scaled charge based on BTM system size, TURN's proposal assigns costs fairly to

---

[227] Ex. SVS-1, page 45.
[228] D.03-04-030.
[229] Ex. TRN-3, pages 49-50, footnote 112. See SCE Schedule CGDL-CRS, SG&E Schedule CGDL-CRS, SDG&E Schedule E-DEPART, PG&E Schedule E-DCG; These schedules collect nonbypassable charges that include the Nuclear Decommissioning Charge, Public Purpose Program Charge, Competition Transition Charge, Power Charge Indifference Adjustment, DWR bond charges, Wildfire Fund Charge, and Energy Cost Recovery Amount (PG&E only).
[230] Ex. TRN-3, page 50. Northern States Power Company offers an Electric Vehicle Home Service rate schedule that bills the customer for plug-in electric vehicle (PEV) usage based on consumption data from the customer's utility-approved charging equipment), eliminating the need for a separate utility-grade meter for loads. PEV consumption is subtracted from the main meter to bill the customer's non-Electric Vehicle electricity usage. This enables the PEV to be billed under a mandatory TOU rate structure with the balance of residential consumption to be billed under a different rate structure.

customers and accounts for a wide array of usage and self-consumption patterns. This approach is fair to NEM customers and ensures that non-participants are not required to disproportionately pay for cost obligations that are not offset by BTM production and are properly shared by all customers.[231]

4. Up-front incentive (Market Transition Credit)

TURN proposes a Market Transition Credit (MTC) in the form of a one-time upfront subsidy payment to ensure sustainable growth and achieve equity goals.[232] TURN's proposed MTC is designed to transparently reflect the entirety of any incentives and subsidies provided to NEM participants. While the remaining elements of TURN's proposal would fairly compensate NEM participants for the value they provide to all customers and the electrical grid, the MTC buydown provides a transparent subsidy lever designed to achieve Commission-defined customer adoption objectives.

a. Rationale and Structure

Rather than providing the MTC in the form of incremental value for export compensation over a defined period of time (as is suggested in the E3 White Paper)[233], TURN recommends structuring the MTC as a one-time upfront rebate. This approach would serve two key objectives.[234] First, the participating customer could apply the entire MTC amount to reduce the costs of new investment as a direct offset at the time of purchase. Second, apart from these one-time costs there would be no ongoing subsidies embedded in retail rates and no continuing concern about growing cost-shifting impacts for existing customers. The MTC, when paired with TURN's successor tariff proposal, provides the Commission with a transparent upfront subsidy

[231] TURN's proposal in this proceeding is not meant to suggest that any customers, whether served under the successor tariff or not, should be forced to bear any unreasonable or excessive utility costs.
[232] These goals are identified in Public Utilities Code §2827.1(b)(1).
[233] *ALJ Email Ruling Introducing White Paper, Noticing Workshop on White Paper, and Providing Instructions for Successor Proposals*, January 28, 2021.
[234] Ex. TRN-1, pages 51-52.

mechanism that can be used to target adoptions and would not lead to cost shifts outside of the MTC.

Because TURN's MTC would be provided as an upfront incentive, a participating customer would know the exact amount they are eligible to receive before making any new investment or financial commitment. The usefulness of upfront compensation is recognized by many parties, including those representing the solar industry.[235] Moreover, because TURN's successor tariff is carefully calibrated to ensure minimal cost shifting, there would be no oversubsidization in the years after payback is achieved.

An up-front MTC is consistent with California's longstanding approach to supporting BTM solar and other distributed energy resources over the past several decades.[236] Starting in 1998, the California Energy Commission (CEC) administered up-front rebates for solar and small wind through the Emerging Renewables rebate program.[237] In 2007, the CPUC launched the California Solar Initiative (CSI) to provide up-front rebates for smaller BTM solar systems.[238] These programs were hailed as successful efforts to stimulate the solar market and became widely accepted by customers and vendors. Rebates were typically used to offset system installation costs. Although neither the CEC nor CSI programs provide new rebates to the general market, the Commission continues to rely on up-front funding support for low-income customer solar adoption through the Solar on Multifamily Affordable Housing (SOMAH)

---

[235] Ex. CSA-1, page 15 ("frontloading customer savings is more effective and less risky than backloading customer savings. Having higher savings in the earlier years and lower savings in the later years helps customers achieve cost recovery in a reasonable timeframe while ensuring that any long-term cost impacts are manageable.")

[236] Ex. TRN-1, page 52.

[237] This program was originally authorized pursuant to SB 90 (Sher, 1997) which codified the relevant language in Public Utilities Code §383.5(d)(section subsequently repealed).

[238] The CSI offered capacity-based up-front rebates for residential systems and performance-based rebates for larger systems typically installed on commercial and institutional customer premises. The initial authorization for rebates was provided in D.06-01-024.

program and the Disadvantaged Communities Single-Family Solar Homes (DAC-SASH) program.[239]

Similar to these past approaches, the MTC should be administered by the Commission for customers of all three IOUs. The Commission may choose to delegate MTC program administration to a non-utility entity in a manner similar to the structure used for the remaining elements of the CSI program. The identification of an appropriate administrator should occur as part of the implementation of the MTC. Any administrator should be selected based on its ability to take advantage of California's extensive experience designing and implementing a wide variety of successful upfront incentives.[240] This experience includes the CSI incentive that varied by customer type (residential/commercial and government/nonprofit) and cumulative installed MW, and the SGIP incentive that varied by generation technology, or for storage installations, customer type (residential, large), ITC status for large installations, and equity (residential, non-residential, with and without ITC).[241]

The up-front MTC would be structured as a $/kW-ac payment that varies based on the installation year, the target benefit/cost ratio, and a target discounted payback period.[242] Details on the methodology for calculating the MTC are included in TURN's model.[243] In this proceeding, the Commission can adopt an initial MTC value for each IOU. Unless warranted by more frequent material changes in key input values, the

---

[239] Ex. TRN-1, page 52.
[240] Ex. TRN-3, page 57, *citing* CSI Handbook January 2017 and SGIP Handbook December 2017. This experience includes the CSI incentive that varied by customer type (residential/commercial and government/nonprofit) and cumulative installed MW, and the SGIP incentive that varied by generation technology, or for storage installations, customer type (residential, large), ITC status for large installations, and equity (residential, non-residential, with and without ITC).
[241] CSI Handbook January 2017 and SGIP Handbook December 2017.
[242] Ex. TRN-1, page 52.
[243] Ex. TRN-5, The payback logic can be found in the "DER Pro Forma Incentives" tab of the model. Key input assumptions and results are shown in the "Results Dashboard" tab.

MTC should be reviewed periodically to ensure that the amounts accurately reflect all key inputs relevant for a system to be installed in the following year.[244]

A key strength of the MTC is its ability to account for changes in tax incentives, avoided cost values and installed system costs. While the current Investment Tax Credit (ITC) is scheduled to ramp down to 0% for residential customers after 2023, Congressional action could halt the ITC decline, restore it to the prior 30% level or increase the ITC and couple it with additional new tax benefits for behind the meter generation and storage systems.[245] TURN's proposal specifically incorporates ITC and other tax law changes into the MTC calculation. If these tax benefits change, the MTC would adjust to ensure that eligible customers achieve the target payback period. Similarly, the MTC can be updated as appropriate to incorporate changes in observed capital costs for new renewable generation and paired storage (if applicable). This dynamic and self-correcting feature of TURN's successor tariff should be seen as a core strength that supports the goal of efficiently achieving defined adoption goals without excessively burdening non-participating customers.

b. Eligible customers

While the Commission may choose to make the MTC available to any customer, TURN recommends prioritizing the use of any ratepayer-funded incentives for low-income CARE customers. TURN's eligibility recommendations are as follows:[246]

[244] Key inputs include system costs, tax incentives, and projected ACC values.
[245] Ex. SVS-3, page 56; Ex. TRN-3, page 53.
[246] RT Vol. 9, pages 1547-1549, Chait.

Customer type	MTC Eligible	Funding source
CARE/FERA – stand-alone generation and generation with paired storage[247]	Yes	Ratepayer funded (Legacy NEM customers + PPP)
Non-CARE with paired energy storage	Only if Commission desires to promote Non-CARE solar + storage adoptions	Unless external funding source obtained, ratepayer funded (PPP)
Title 24 New Solar Home	Only if Commission finds it necessary to achieve Title 24 cost-effectiveness goals	Unless external funding source obtained, ratepayer funded (PPP)
Non-CARE with stand-alone generation	Only if Commission desires to promote Non-CARE standalone PV adoptions and can use non-rate sources of funding.	External funding source (costs not collected in rates)

For CARE customers, TURN recommends setting the MTC level to yield a full discounted payback period of 10 years.[248] This timeframe represents a reasonable horizon for recovering the costs of an initial investment for an eligible participant. Because of the significant costs of providing an up-front subsidy to achieve a 10-year payback to all new successor tariff customers, TURN proposes giving priority to CARE eligible customer retrofits on existing properties. These customers face the largest challenges in achieving reasonable payback periods and should be the focus of future incentives to achieve equity and affordability objectives.

Based on 2021 ACC values and assuming the other elements of TURN's successor tariff are adopted, TURN calculated average MTCs for CARE customers of $1.74/watt-ac

[247] TURN supports allowing FERA customers to receive a ratepayer-funded MTC but did not specifically model this scenario in its testimony.
[248] Ex. TRN-1, page 53. In rebuttal testimony, TURN also modeled an MTC that yields a 13-year full discounted payback for CARE customers (Ex. TRN-3, pages 88-90)

(PG&E), $2.23/watt-ac (SCE) and $2.33/watt-ac (SDG&E).[249] Assuming an average system size of 4 kW, the total MTC cost would be approximately $70-90 million/year for 10,000 new customers. According to Cal Advocates, less than 9,000 CARE customers were newly enrolled in NEM tariffs in 2019.[250] If the successor tariff results in a doubling of new CARE enrollments, the cost would be approximately $140-180 million/year.[251]

The Commission could also evaluate authorizing different payback periods for MTCs available to low-income customers located in disadvantaged communities and customers eligible for the Solar on Multifamily Affordable Housing (SOMAH) program, the Single-family Affordable Solar Homes (SASH) Program and the Disadvantaged Communities - Single-family Solar Homes (DAC-SASH) program. The availability of MTCs for participation in these programs could supplement existing funding sources used to support these initiatives and take into account other available incentives for these customers. The Commission could also expand MTC eligibility, or authorize a different payback timeframe, for other disadvantaged customer subgroups to support various policy, equity and environmental objectives.

As explained in rebuttal testimony and during hearings, TURN recommends that any ratepayer funded MTC incentives provided to non-CARE customers should be limited to paired generation and energy storage.[252] This prioritization is based on the higher TRC and RIM results associated with these projects versus standalone solar.[253] Although identifying sources of funds outside of rates would be preferable, TURN can

---

[249] Ex. TRN-1, page 73.
[250] Ex.PAO-1, page 3-56
[251] TURN also provided an illustrative scenario where 50,000 new CARE customers receive the MTC each year and assumed a total annual cost of $300 million. (Ex. TRN-1, page 55) However, this level of adoption is more than 5x greater than recently observed levels.
[252] RT Vol. 9, page 1548, Chait.
[253] Ex. TRN-3, page 71.

support the use of ratepayer funds (if deemed necessary) to support paired storage installations for non-CARE customers.

TURN does not support making the MTC available to new residential construction covered by the Title 24 solar requirements unless the Commission finds it is necessary to satisfy a cost-effectiveness test pursuant to the Title 24 program.[254] If the Commission authorizes a community solar program option that is cost effective for customers subject to the mandate, it may not be reasonable to provide any MTC for onsite generation by these customers.

Absent the use of a funding source outside of retail rates, TURN is not proposing to make an MTC available to residential non-CARE customers for stand-alone solar generation. If a source of funds external rates can be secured, the Commission should consider making the MTC available to non-CARE customers with stand-alone generation. TURN's modeling includes a sensitivity in which non-CARE customers are eligible for an MTC with a 15-year discounted payback period.[255]

If the Commission finds that a different payback period, or payback metric, is appropriate for any eligible customer, TURN's proposed MTC can be calculated accordingly. The adaptability of the MTC to different cost and financing assumptions, avoided cost values, and payback periods, allows the Commission to adopt a cost-based tariff design and use the up-front incentive as the key method of driving any desired customer adoption rate.

c. Funding sources

The establishment of a separately administered MTC would facilitate the incorporation of funding sources other than rate revenues collected from all customers. The most suitable sources that could be used to pay for some or all MTCs paid to participants are

[254] RT Vol. 9, page 1584, Chait.
[255] Ex. TRN-3, pages 85-87.

state general fund monies including Cap-and-Trade funds (from the Greenhouse Gas Reduction Fund).[256] TURN's model allows for the availability of external state funds to reduce ratepayer funding for the MTC and calculate the resulting Rate Impact Measure (RIM) test results.[257] Funding some or all of the MTC costs through sources other than retail rates would materially improve RIM test outcomes.[258]

Although TURN recognizes that the Commission cannot order the Legislature to appropriate money for this purpose, the Commission can adopt an incentive mechanism capable of accommodating external funding that becomes available over time and condition the expansion of the MTC to certain customer groups (such as non-CARE customers) on the availability of adequate funding from alternative sources.

For MTC costs that must be recovered in rates, TURN offers two approaches to collection. First, the Commission should adopt a new surcharge applied to existing non-CARE NEM 1.0 and 2.0 customers to collect a portion of the MTC costs. Existing CARE NEM customers would be exempted from this surcharge. This approach is justified because of the enormous financial benefits that legacy NEM customers continue to realize under the existing tariffs and the longer payback periods for CARE customers.[259] In rebuttal testimony, TURN modeled illustrative monthly charges on legacy non-CARE NEM customers to support 25%, 50% and 100% of the MTC funding needs assuming various levels of need (deployments and MTC level). At an average MTC of $2/watt and 25,000 new installations per year (2.5x recent observed levels), recovering 50% of total funding needs from legacy non-CARE NEM customers would require a

[256] Ex. TRN-1, page 54. Other sources could include federal government infrastructure funding or general obligation bonds repaid through the state general fund.
[257] Ex. TRN-5, See "Results Dashboard" tab, Allocation of Buydown Incentive options.
[258] Ex. TRN-1, page 75, RIM scores for CARE customers under TURN's successor tariff improve from 0.37-0.45 with a ratepayer funded MTC to 0.67-0.89 if 75% of MTC funds are obtained from non-rate sources.
[259] The disparate payback periods for CARE and Non-CARE customers under existing NEM tariffs is highlighted in Section IV.

monthly charge of $8.33/customer.[260] The monthly charge would be significantly lower if new CARE customer installations track closer to the historical pace. The amount of the charge can be adjusted upward or downward based on need, funding levels, and the appropriate share of responsibility assigned to legacy NEM customers.

Second, TURN recommends collecting the remaining MTC funding needs from all customers through the Public Purpose Program charge allocated on an equal cents per kilowatt-hour basis.[261] This approach would spread cost responsibility fairly and is consistent with the allocation of cost responsibility for the CARE discount. The collection of remaining MTC costs via PPP recognizes that the incentive is designed to achieve important state environmental and equity goals, similar to other cost categories recovered in this manner. Alternatively, the Commission could seek Legislative authorization to securitize MTC costs so the rate impacts would be spread out over a 10- to 20-year period.

5. *Paired Storage rate and dispatch obligations*

TURN proposes that customers with paired storage be placed on an electrification tariff to support optimal dispatch that benefits the grid and all customers.[262] The Commission should make participation in an electrification rate mandatory for any customer (including legacy NEM 1.0 and 2.0 customers) that installs paired storage after receiving an incentive through the Self-Generation Incentive Program (SGIP).[263] The Commission should further direct the IOUs to propose, in the appropriate rate design proceedings, a separate tariff for paired storage that includes additional time of use (TOU) granularity and TOU price signals that are better aligned with grid conditions.[264] The resulting tariff should be designed to incentivize optimal dispatch to benefits the grid and all

---

[260] Ex. TRN-3, page 64.
[261] Ex. TRN-1, page 55.
[262] Ex. TRN-1, pages 56-57.
[263] Ex. TRN-3, page 72.
[264] Ex. TRN-3, page 73.

customers and provide appropriate compensation for performance during periods of peak need.

In the near-term, participants are likely to invest in residential storage installations based on a desire to remain energized during short-term unplanned outages, during intentional multi-day utility shutoffs triggered by imminent wildfire risks, and in the event of natural disasters.[265] These private benefits could be substantial for customers located in areas facing outages and may be sufficient to motivate investments in paired storage even when the tariff is not expected to yield sufficient bill savings to justify the initial investment for a decade or more.

TURN's analysis finds that TRC values are significantly higher for solar and paired storage installations compared to stand-alone solar. While stand-alone solar projects are not close to being cost effective, the results for NEM-eligible Solar PV paired with battery storage (paired storage) are more encouraging. Compared to stand-alone solar installations, paired solar and storage systems provide larger avoided cost benefits, improve economics to participating customers, and reduce cost shifts from participants to nonparticipants.

TURN used its model to compare cost effectiveness for the E3 SCE Non-CARE customer taking service on SCE's D-PRIME rate after successor tariff participation. The results compare a standalone solar customer with a paired solar and storage customer assuming a 2023 installation, TURN's successor tariff proposal and 2021 ACC values. For this analysis, TURN considered scenarios without any MTC and with an MTC set at $1,720 per kW (designed to achieve a 15-year full discounted payback for a standalone solar customer). The results are shown on the following table:[266]

[265] Ex. TRN-1, page 56.

[266] Ex. TRN-3, pages 71-72, Tables 11-12 (results are combined into a single table for purposes of clarity).

Paired Storage versus Standalone PV Cost Effectiveness Results for 2023 TURN's Successor Tariff Proposal on SCE TOU-D-4-9 rate schedule with 2021 ACC values						
Technology	**MTC incentive**	**TRC**	**RIM**	**PCT**	**Present Value Avoided Costs ($)**	**Present Value Avoided Costs ($/kWh)**
Standalone PV	No	0.37	0.74	0.55	$4,547	$0.06
Standalone PV	Yes / 15-year	0.37	0.41	1.06	$4,547	$0.06
Paired Storage	No	0.59	0.87	0.74	$12,122	$0.19
Paired Storage	Yes / 15-year	0.59	0.62	1.01	$12,122	$0.19

These results indicate that paired storage yields materially better cost effectiveness outcomes across TRC, RIM and PCT metrics compared to standalone solar PV. The results also show that avoided costs are over three times higher for paired storage ($0.19/kWh) versus standalone PV ($0.06/kWh). This assessment demonstrates that, for Non-CARE customers, paired storage installations should be strongly preferred over standalone PV. When adding the MTC, TRC and avoided cost values are unchanged (relative to a no MTC scenario) but the RIM score falls from 0.74 to 0.41 for the stand-alone solar customers and from 0.87 to 0.62 for the paired storage customer. The smaller reduction in the RIM score, and the higher remaining result, for paired storage makes this investment more desirable from a non-participating customer perspective.

Based on this analysis, TURN believes that if the Commission desires to support penetration of solar PV via a MTC mechanism, it should do so through support of paired storage resources rather than standalone PV. TURN recommends that any ratepayer funded subsidies provided to non-CARE residential customers through the MTC be focused on paired solar and storage systems.[267] The Commission has already authorized rebates through 2024 for BTM energy storage deployment by residential customers that covers 25% of the average system cost for a non-CARE customer, 85% of the average cost for a low-income customer meeting certain criteria, and 100% of the

[267] Ex. TRN-3, pages 70-72.

average cost for low-income and medical baseline customers that face high fire risks.[268] Any additional MTC for paired storage should account for these existing incentives and coordinate with the SGIP program going forward.[269]

TURN also proposes requiring any paired storage unit participating in the successor tariff be required to discharge during certain extreme system stress and emergency conditions in support of overall grid needs.[270] In order to accommodate this requirement, paired storage should have the capability to respond to remote dispatch instructions from a third-party aggregator, the IOU or a CCA/DA provider, or the California Independent System Operator. This capability should be used to require dispatch to a pre-determined minimum capacity level during a Stage 2 emergency or during extreme summer net peaks when CAISO has identified concerns about overall generation insufficiency.[271]

TURN would not apply the dispatch obligation in the event of planned outages or Public Safety Power Shutoff events, none of which could be avoided through the dispatch obligation. TURN also proposes to exempt medical baseline customers from any dispatch requirements.[272] Moreover, TURN witness Chait explained that it would be reasonable to allow any customer to pre-select the maximum discharge level for emergency events.[273] Compensation to paired storage customers would be provided through either an up-front incentive (like the MTC) or through separate annual compensation that reflects the amount of services being provided to the grid.[274]

---

[268] D.20-01-021
[269] Ex. TRN-3, pages 73-74.
[270] Ex. TRN-1, page 57.
[271] Ex. TRN-1, page 57, footnote 98. The CAISO defines a stage 2 emergency notification as a situation where "The ISO has taken all mitigating actions and is no longer able to provide its expected energy requirements. Requires ISO intervention in the market, such as ordering power plants online."
[272] RT Vol. 9, page 1534, Chait; RT Vol. 10, page 1662, Chait.
[273] RT Vol. 10, page 1662, Chait.
[274] RT Vol. 10, page 1662, Chait.

The obligation to accept remote dispatch and to discharge under these conditions is intended to address the countervailing motivation of customers to resist discharging if there is a known risk of an extreme weather event or widespread outage. Requiring that such systems operate in a manner consistent (and not at odds) with grid needs during severe conditions should be a condition precedent to eligibility for successor tariff participation for paired storage resources.

C. Concerns about other party proposals

1. Export Compensation

A large number of parties propose to tie export compensation to retail rates either through a continuation of NEM 2.0 or through a set of step-downs that would set export rates for each new tranche of enrolled customers at a pre-determined percentage of the applicable retail rate. Parties proposing this approach include CalSSA, SEIA/VS, Sierra Club and Grid Alternatives. TURN opposes these approaches to export compensation as part of any end-state tariff design.[275]

Retail rate-based compensation is problematic for three primary reasons.[276] First, the use of retail rates yields substantial escalating cost shifts over time including significant over-compensation beyond the expected payback year. Second, this approach prevents the Commission from adjusting export compensation for a given tranche of adoption to better align with avoided costs over time. Third, parties have not provided any robust method of using retail rates for export compensation that reasonably approximates ACC values over time. The concerns are explained in the following sections.

[275] For the reasons discussed in Section V(A), TURN supports linking export compensation to a discounted retail rate only for purposes of an interim tariff that would be in place prior to the implementation of the end-state tariff.
[276] Ex. TRN-3, pages 29-41.

a. Proposals to link customer export credits to retail rates would result in escalating cost shifts over time and do not align with avoided cost values

The approach of linking export compensation to retail rates is generally inconsistent with the requirement that the successor tariff be "based on the costs and benefits" of the generator in a manner that results in costs and benefits being "approximately equal."[277] The Commission should decline to approve any end-state successor tariff that fails to satisfy this requirement, which is presumptively violated if export compensation is linked to retail rates that do not approximate the adopted Avoided Cost Calculator values.

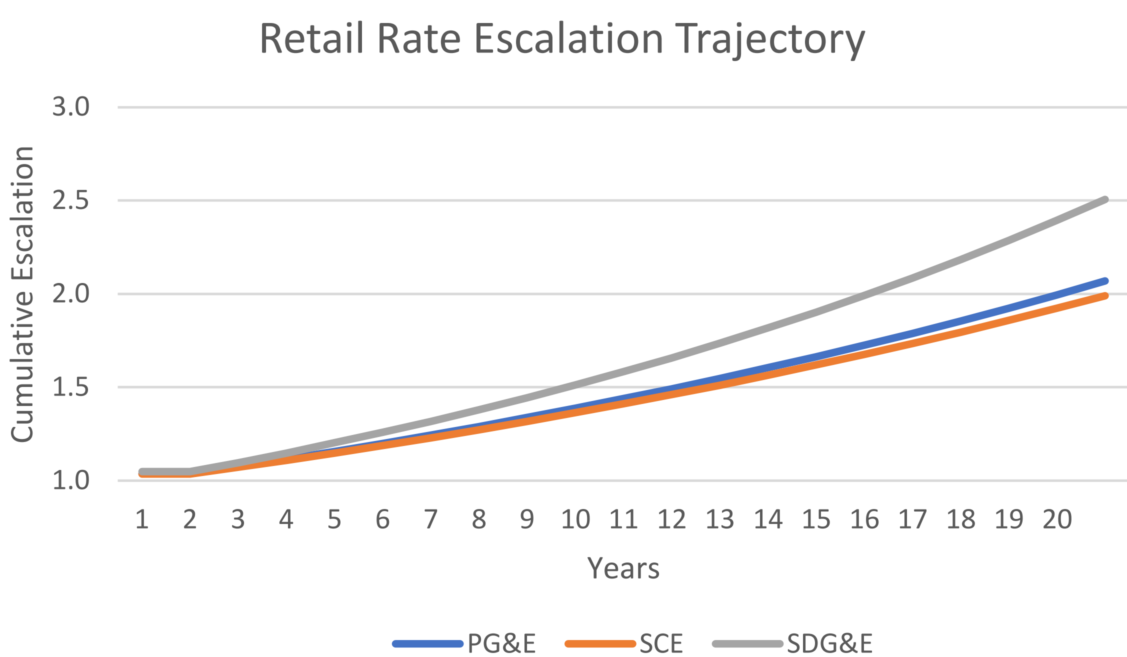
CalSSA would set export compensation for non-CARE residential customers at a fraction of the applicable retail rate beginning at 90-95% (or 95-100% for solar + storage) for the first step of enrollments and reduce the fraction to 45-70% (or 80-100% for solar + storage) for enrollments expected to occur in 2030.[278] In rebuttal testimony, CalSSA offers an alternative that would set export compensation for each step based on a percentage of retail rates that reflects a defined % of movement towards ACC values.[279] Under either proposal, any new customer would retain the right to export compensation at the designated fraction of the applicable retail rates in effect over the following 20 years. SEIA would similarly set export compensation for each tranche of new customer enrollments based on a set percentage of the applicable retail electrification rate for SDG&E and PG&E.[280]

As explained by TURN witness Chait during hearings, a key problem with the use of retail rates (including a discounted percentage) for export compensation is both the rate structure itself and retail rate escalation. Ms. Chait noted that "over a long time, there could be a material mismatch between the escalation in retail rates and the avoided

[277] Guiding Principle #1 (Compliance with the requirements of §2827.1); Cal. Pub. Util. Code §2827.1(b)(3), (b)(4).
[278] Ex. CSA-1, page 7.
[279] Ex. CSA-2, pages 47-48.
[280] Ex. SVS-1, page 10.

costs, and that is what drives the cost shift."[281] The approaches proposed by various solar parties do not adequately address this concern.

Setting compensation as an explicit percentage of retail rates would backload the benefits to successor tariff customers. The following chart shows the nominal compound annual escalation trajectory for PG&E, SCE and SDG&E using values from the February 2021 CPUC Rates *En Banc* Whitepaper.[282] These values are conservative and do not account for large spending initiatives recently announced by the IOUs. By year 20, nominal retail rate escalation is expected to increase by up to 2.5x. By comparison, the solar weighted 2021 ACC values are expected to increase by a factor of 1.55 for PG&E, 2.07 for SCE, and 1.79 for PG&E over the 2023-2042 period.[283]



It is not reasonable to adopt an export compensation method that would lock compensation at minimum levels well above avoided cost and continue to escalate

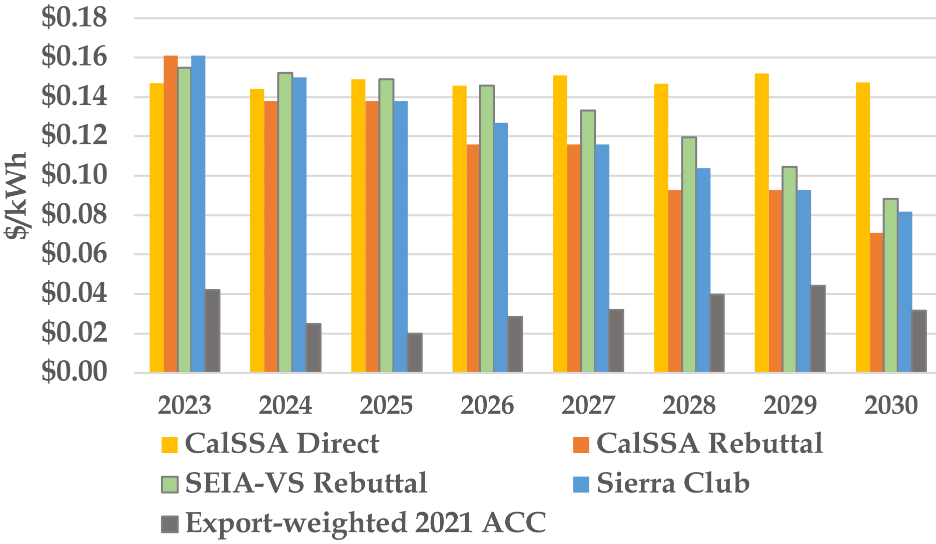
[281] RT Vol. 10, page 1660, Chait.
[282] Ex. TRN-3, page 32, Figure 2.
[283] Ex. TRN-3, page 31.

these values over the following 20 years. This outcome is inconsistent with statutory requirements because the level of export compensation would have no defined relationship to the benefits provided by the generation export.

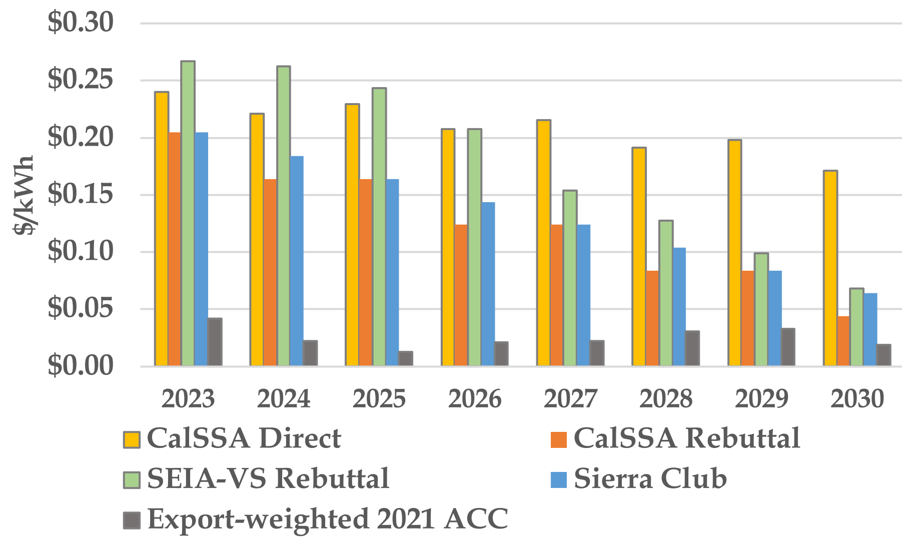
The following figures compare the average 2021 solar export-weighted ACC value with the first year of export compensation under each new tranche of installations for the CalSSA (direct and rebuttal alternative), SEIA/VS (rebuttal) and Sierra Club non-CARE successor tariff proposals for SCE and PG&E. For SCE, the export-weighted ACC amounts to only 13-14% of the CalSSA, SEIA-VS, and Sierra Club proposed export compensation in the lowest year (2025) and is only 21-44% in 2030. For PG&E, the export-weighted ACC amounts to as low as 5-8% in 2025 and is only 11-43% in 2030.[284]

[284] TURN used the same data for this analysis that was used to derive Figures 3 and 4 on page 33 of Ex. TRN-3. The only updates were to include revised proposals included in CalSSA and SEIA/VS rebuttal testimony.

Comparison of average SCE 2021 solar export-weighted ACC value with first year of each tranche of retail rate export compensation under SEIA/VS, CalSSA, Sierra Club proposals[285]



Comparison of average PG&E 2021 solar export-weighted ACC value with first year of each tranche of retail rate export compensation under SEIA/VS, CalSSA, Sierra Club proposals[286]



---

285 Ex. TRN-3, page 33; This chart has been modified to show the SEIA/VS revised proposal in rebuttal testimony (Ex. SVS-3, page 23) and to add export compensation for the CalSSA alternative proposal and Sierra Club as shown in Ex.CSA-2, page 50, Table 8. The chart shows export compensation for SCE using the D-PRIME retail rate. TURN also corrected the prior erroneous assumption that the base rates discounted by CalSSA include nonbypassable charges.

286 Ex. TRN-3, page 33; This chart has been modified in the same manner as described in footnote 258 but uses PG&E E-TOU-B.

These figures understate the disconnect between the proposed export rates and ACC values because they only reflect differences in the first year of the tariff for participating customers. The decline in export compensation values shown for CalSSA, SEIA/VS and Sierra Club over the 2023-2030 timeframe would only apply to new customers. Existing customers would retain the retail rate value they receive at the time they first enroll.

Sierra Club proposes to lock in export compensation for 20 years based on existing (2021) retail rate levels for each IOU's electrification rate subject to a declining % for each tranche of new enrollments.[287] Sierra Club proposes using short-run (annual) ACC values, rather than a long-run leveled value, for both the step-down and the final export compensation rate applied to new customers after 10 GW of new customer solar has been deployed.[288] Sierra Club also proposes that export compensation for any existing customer be adjusted upwards if subsequently developed ACC values increase.[289]

Although Sierra Club did not present cost effectiveness results in its testimony, TURN analyzed this approach in rebuttal testimony. This analysis shows that for 2023-2025 installations, compared to other solar party proposals, the Sierra Club successor tariff does not materially improve the RIM cost test results, lengthen the payback period, or reduce the expected Rate of Return for customer investments.[290] As shown on the prior page, Sierra Club's proposal would lock in long-term export compensation at levels well above avoided cost for another 10 GW of behind the meter solar capacity. This approach would result in long-term compensation for new customers that substantially exceeds the benefits of the generation to the grid and all customers. The resulting cost shift would be disproportionately borne by non-solar customers including low-income customers without solar.

---

[287] Ex. SCL-1, pages 3-4.
[288] Ex. SCL-1, page 27
[289] Ex. SCL-1, page 27
[290] Ex. TRN-3, pages 85-87, 91.

Finally, it is not clear whether any of these proposals would appear to lock in existing TOU periods for 20 years for purposes of export compensation even if different TOU periods or TOU ratios are used for import rates over that same timeframe.[291] The potential disconnect between TOU ratios and TOU periods governing import and export rates is not addressed in testimony. This issue is just one example of the dangers of authorizing locked in export compensation for a period of 20 years.

b. Export compensation should not be aligned with levelized Avoided Cost values

Several parties propose that the successor tariff should ultimately transition to provide export compensation that tracks with avoided costs. While some parties propose using short-term avoided cost values (TURN, Cal Advocates, SBUA), CalSSA proposes setting export compensation at the fraction of retail rates that reflects "levelized lifetime avoided costs" only for new customers that enroll in Step 5 (assumed to occur in 2030).[292] Compensation for all customers would be tied exclusively to a declining fraction of retail rates. Customers enrolling in Step 5 would receive compensation equal to export-weighted levelized lifetime avoided costs only in the first year. If retail rate escalation is greater than avoided cost escalation, as is expected, compensation for Step 5 customers would exceed 25-year export-weighted levelized avoided costs in all but the first year.[293] Customers enrolling prior to Step 5 would receive compensation that is higher than levelized lifetime avoided costs in all years.

In support of its approach, CalSSA states "setting compensation calibrated to levelized lifetime avoided costs and sticking with it is a fair and consumer-friendly policy."[294] TURN disagrees that this policy is either "fair" or "consumer friendly". Regardless of when such a proposal would take effect, TURN opposes setting export compensation based on levelized ACC values that extend over a period of 20 or more years. As shown

[291] RT Vol. 7, page 1159, Heavner.
[292] Ex. CSA-1, pages 20 and 39.
[293] Ex. TRN-3, pages 34-36.
[294] Ex. CSA-1, page 20

in TURN's rebuttal testimony, a comparison of this proposal with PG&E's avoided costs shows that CalSSA's approach in its final proposed steps would still materially exceed 25-year levelized 2020 ACC costs in all but a handful of years.[295]

An additional concern is the fact that CalSSA proposes 25-year levelized ACC values rather than 20-year ACC values even though the term of their successor tariff proposal is limited to 20 years.[296] The 2025 levelized value for the 2020 ACC ($0.135 per kWh for the PG&E scenario examined) is $0.016 per kWh higher than the 20-year levelized value ($0.119 per kWh).[297] Even if the Commission agrees to base export compensation on a share of retail rates calibrated to levelized ACC values (which TURN opposes), there is no basis for including additional years that go beyond the duration of the proposed tariff.

CalSSA argues that value of GHG reductions occurring over the course of the entire 25-year period covered by the ACC should be included in the levelized value provided to customers starting in the first year of project operations.[298] There are four primary issues with CalSSA's approach.[299] First, the 2020 ACC GHG values increase quite substantially over time, a phenomenon that could also occur in future ACC updates. Compensating exports using a levelized ACC value produces a cost shift because annual ACC values are utilized to quantify benefits under the RIM test and solar panel degradation reduces exports over time. Second, since the Commission's GHG Adder and Cap and Trade trajectories already establish the authorized value of GHG emission reductions in each year of the ACC, no levelization is required. Third, providing compensation for values that extend beyond year 20 could result in double payment if these same out-year values are included in export compensation provided to customers after year 20. Fourth, the out-year values included in a 20- or 25-year ACC snapshot are

[295] Ex. TRN-3, pages 34-36.
[296] Ex.CSA-1, pages 13, 58.
[297] Ex. TRN-3, page 36.
[298] Ex.CSA-1, page 15.
[299] Ex. TRN-3, pages 36-37.

not reliable and are subject to significant change in future ACC updates. Indeed, the material changes to these later year values in the 2021 ACC update demonstrate the challenges of relying on (and levelizing) one iteration of long-term ACC values for purposes of export compensation.

While opposing using long-term (20 or 25 year) ACC values as the basis for up-front compensation, TURN proposes an alternative approach that would allow new successor tariff customers to lock into ACC values for a duration of 5 or 10 years. TURN's approach does not incorporate levelization. Instead, TURN would allow the successor tariff customer to have confidence with respect to all ACC values that apply in each of the following years for a duration of up to a decade. This approach promotes confidence in the economics of new investments over this time horizon and results in no cost shifting related to export compensation. TURN believes that this approach is both "consumer friendly" and "fair" to all customers and should be adopted as an alternative to the CalSSA proposal.

c. Solar parties fail to incorporate any adjustments to export compensation in the event that the Investment Tax Credit is extended

In direct testimony, SEIA/VS note the challenges associated with the "scheduled step-down" in the Investment Tax Credit that is currently scheduled to ramp down to 0% for residential customers after 2023.[300] Although this ramp down is expected under current law, it is not possible to predict future changes to federal tax policy with any level of confidence. Prior to 2023, Congress could halt the ITC decline, restore it to the prior 30% level or increase the ITC and couple it with additional new tax benefits for behind the meter generation and storage systems.[301] Moreover, the ITC is currently available to businesses pursuant to Section 48 for projects that commence construction prior to December 31, 2023 and are placed into service prior to January 1, 2026.[302] If the credit

[300] Ex. SVS-3, page 56.
[301] Ex. TRN-3, page 53.
[302] 26 USC §48(a)(6)(B).

may be taken by installers that retain ownership of systems and provide them to residential customers under lease arrangements, the value of the ITC could be incorporated into the pricing for leased systems installed after 2023.[303] Given the significant impact of the ITC on the payback period for a residential customer, and the major role it plays in financing assumptions, the Commission should ensure that any successor tariff is capable of adapting to changes in the availability and level of the ITC.

CalSSA states that no provision of its tariff would change even if Congress extends or expands the Investment Tax Credit for residential customers.[304] While SEIA/VS agrees that ITC extensions could serve as a basis for changing the successor tariff, and acknowledging "the uncertainty of the ITC expiration in 2024"[305], SEIA/VS witness Beach stated "I don't think I can say how our proposal would necessarily change."[306] In response to additional questions, SEIA/VS witness Beach suggested that the Commission could consider the issue in some proceeding but could not explain how the tariff could be changed to ensure that any benefits of an ITC extension would be shared with all customers.[307]

The failure of parties like SEIA/VS and CalSSA to identify any method for adjusting the successor tariff to account for significant changes in tax policy constitutes a major problem with their overall proposals. If new or enhanced tax incentives are authorized, these parties would effectively assign 100% of the benefits entirely to vendors and/or successor tariff customers. This outcome would be manifestly unfair given the large subsidies and cost shifting already embedded into the solar party tariff proposals. Any extension or expansion of the ITC should trigger adjustments to the successor tariff to

---

[303] The commencement of construction may be satisfied through an initial financial commitment to purchase equipment that is installed at a later date.
[304] RT Vol. 7, page 1146, Heavner.
[305] RT Vol. 8, page 1301, Beach.
[306] RT Vol. 8, page 1296, Beach.
[307] RT Vol. 8, page 1297, Beach.

recognize the lower costs faced by participants and reduce the cost shifting burden on non-participating customers.

By contrast, TURN's proposal specifically incorporates ITC and other tax law changes into the MTC calculation.[308] If these tax benefits decline or disappear, the MTC would adjust upwards to ensure that eligible customers can still achieve the target payback period. If the tax benefits do not decline or even increase over time, the MTC would adjust accordingly to solve for the same target payback period and benefit-cost ratio. This dynamic feature of TURN's successor tariff is a core strength that supports the goal of efficiently achieving defined adoption goals without excessively burdening non-participating customers.

2. *Import Rates and Charges for Self-consumption*

a. *Compensating self-consumption at full retail rates would increase cost shifting over the life of the system.*

Many parties seeking to continue the basic structure of current net metering propose to compensate new successor tariff customers for a large portion of their generation output at full retail rates that escalate over time. Specifically, parties like SEIA/VS, CalSSA and Sierra Club would allow successor tariff customers to receive full retail rate credits for all generation consumed behind the customer meter. This approach would ensure a growing cost shift for the portion of generation serving self-consumption.

TURN addresses the disconnect between retail rates and avoided cost value escalation in Section V(C)(1)(a). The use of full retail rates to compensate customers for self-consumption quantities fails to reflect the value of the generation to the grid or all customers. In order to ensure that these customers do not unreasonably avoid payment of a variety of nonbypassable and shared costs, the Commission should apply an

[308] Ex. TRN-3, page 54.

additional charge to ensure that the use of solar generation to serve self-consumption does not result in higher rates for all customers.

Retail rate escalation will guarantee increased compensation for generation used for self-consumption over the life of the system. If rate escalation exceeds the forecasts relied upon by parties in this proceeding, the level of compensation to successor tariff customers effectively increases and the cost-effectiveness of the tariff design (based on TRC and RIM scores) declines. SEIA/VS assumes that retail rates escalate at 3.5% until 2030 and then only at 2.2% in all following years.[309] This escalation rate may prove low in the face of an onslaught of IOU spending requests. For example, PG&E's recently filed General Rate Case request (which was not considered by any party) includes an 18% first-year rate increase for residential customers in 2023.[310] In addition, PG&E recently announced an intent to seek Commission approval to underground 10,000 miles of power lines in high fire threat districts, a project that could require $40 billion in utility capital expenditures.[311] These are just two examples of major spending initiatives that could contribute to sustained retail rate escalation in the coming years.

Customer solar deployment could accelerate future retail rate escalation if customer self-consumption is credited at the retail rate and no new Grid Benefit Charges are applied. The deployment of an additional 12 GW of solar, as proposed by several solar parties, would reduce customer contributions to shared system costs (absent a Grid Benefits Charge). Reallocating these costs to other customers would fuel further increases in retail rates. Absent some additional mechanism to fairly collect costs from all customers, the use of full retail rates to compensate self-consumption quantities will materially contribute to higher rate escalation over time.

---

309 Ex. TRN-3, page 14.
310 Ex. TRN-11, page 4-14.
311 Ex. TRN-7.

b. Grid charges proposed by the IOUs, SBUA and Cal Advocates would less accurately assign cost responsibility

Several parties propose grid charges that are designed to collect various fixed, nonbypassable and shared costs from successor tariff customers.[312] While TURN recognizes the relative simplicity of the proposals, they generally result in a less accurate assignment of cost responsibility than TURN's NUS charge (which is assessed on metered or estimated self-consumption quantities). TURN urges the Commission to adopt a mechanism that most accurately quantifies the cost responsibility for each customer.

The IOUs propose both fixed customer charges and grid benefits charges for successor tariff customers. New rate tariffs would be created by SDG&E and PG&E with monthly fixed charges ranging from $20.66 (PG&E) to $24.10 (SDG&E).[313] SCE would require participation in its existing D-PRIME rate with a monthly fixed charge of $12.02.[314] In addition, each IOU would apply a separate Grid Benefits Charge (GBC) based on installed solar capacity to recover distribution, transmission, and the remaining bundled rate components "net of relevant avoided costs as established by the ACC tool."[315] The GBC would be determined based on current rates and "the observed estimated average export percentage of that customer class over the previous year."[316] The proposed GBCs are $10.24/kW-AC (SCE), $14.06/kW-AC (SDG&E), and $14.14/kW-AC (PG&E).[317] For residential customers, Cal Advocates proposes grid charges based on monthly gross on-site consumption (for nonbypassable charges) and $/kW-ac of system capacity (for distribution and transmission fixed costs).[318]

[312] These parties are the joint IOUs, Cal Advocates and SBUA.
[313] Ex. IOU-1, pages 113-116.
[314] Ex. IOU-1, page 123.
[315] Ex. IOU-1, page 139.
[316] Ex. IOU-1, page 138.
[317] Ex. IOU-1, page 143.
[318] Ex. PAO-1, page 3-40.

The collection of GBCs on a $/kW basis is suboptimal because it fails to consider the actual amount of self-consumption by the individual customer. As noted by SEIA/VS, a GBC based on installed capacity would overcharge customers when their generation is not operating or when the customer exports a high percentage of total output (either temporarily or generally).[319] TURN's proposal addresses this defect by calculating each customer's cost responsibility based on the actual (or estimated) quantity of the customer's monthly self-consumption. This approach ensures that customers are not assessed additional cost responsibility when their generation is inoperable or if the customer exports far more generation than would otherwise be expected.[320] In this respect, TURN's approach is superior to the fixed capacity charge proposed by Cal Advocates and the IOUs and more accurately assigns the costs associated with the operation of the generation to successor tariff customers.

The Cal Advocates GBC would collect four nonbypassable charges for self-consumption from onsite generation which are justified based on the charges identified in D.16-01-044.[321] These four charges (PPP, CTC, ND and WFC) only represent a portion of the authorized nonbypassable charges assessed on all other customers. Nonbypassable charges ignored by Cal Advocates include Reliability Services, New System Generation Costs, additional IOU securitization costs relating to wildfires or undercollections, the Power Charge Indifference Adjustment, the Energy Cost Recovery Account (for PG&E), and the PUC Reimbursement Surcharge. While many of these NBCs currently have low values, others are sizable. Some of these NBCs did not exist, or were not separately collected from bundled service customers (*e.g.* PCIA) at the time D.16-01-044 was adopted. By failing to include all NBCs in the GBC calculation, Cal Advocates would increase the obligation of other customers to pay for these nonbypassable costs.

---

[319] Ex. SVS-3, page 71.

[320] For example, a customer that goes away on vacation or lives at their residence seasonally would have very little onsite consumption subject to the charge.

[321] Ex. PAO-1, page 3-15.

The following shows the major nonbypassable charges that are currently collected from non-CARE residential customers.[322]

Major nonbypassable charges by IOU[323] *Non-CARE residential ($/kWh)*			
	PG&E	**SCE**	**SDG&E**
PPP+TRAC[324]	$ 0.0158	$ 0.0162	$ 0.0136
ND[325]	$ 0.0009	$ (0.0006)	$ 0.0001
CTC[326]	$ 0.0000	$ -	$ 0.0008
Wildfire	$ 0.0058	$ 0.0058	$ 0.0058
Cal Advocates NBC total	**$ 0.0225**	**$ 0.0215**	**$ 0.0203**
NSGC / LGC[327]	$ 0.0044	$ 0.0126	$ 0.0085
PCIA[328]	$ 0.0424	$ 0.0253	$ 0.0452
Total of major NBCs	**$ 0.0694**	**$ 0.0593**	**$ 0.0740**
% of major NBCs recovered (Cal Advocates GBC)	32%	36%	27%

Excluded from this list are a series of pending, proposed or recently approved securitization charges for IOU wildfire costs and other undercollections. The magnitude of costs to be securitized will not be affected by the decision of a customer to install behind the meter generation. If approved, these additional IOU charges would be collected from all customers in the form of nonbypassable charges assessed on a cents/kWh basis. Exempting self-consumption by successor tariff customers from these costs would only shift the burden to other customers. This outcome should and can be avoided by requiring all customers, including those served under the successor tariff, to

[322] The costs of smaller NBCs are not included in this table because they do not materially affect the total cost value of all NBCs. TURN believes that all NBCs, regardless of size, should be fully collected from successor tariff customers.
[323] Ex. TRN-3, page 47, Table 8.
[324] Public Purpose Charge + Total Rate Adjustment Component (SDG&E).
[325] Nuclear Decommissioning
[326] Competition Transition Charge.
[327] New System Generation Costs / Local Generation Charge
[328] Power Charge Indifference Adjustment

pay their fair share of approved nonbypassable costs.[329] To support this goal, the Commission should expand the definition of nonbypassable costs adopted in D.16-01-044 to include the broader list of charges that are applied on a nonbypassable basis and ensure that these costs are fully and fairly collected from successor tariff customers based on both imports and self-consumption quantities.

c. Minimum bill

TURN does not propose any increases in the minimum bill as a strategy for increasing the collection of fixed or shared system costs from successor tariff customers. Instead, TURN proposes to delink export compensation from retail rates, to collect all fixed and shared costs associated with imports through import rates, and to collect costs associated with self-consumption using a NUS charge that is based on self-consumption quantities each month. There are several reasons why TURN strongly prefers the NUS charge to an enhanced minimum bill.

The NUS charge is a more accurate method of assessing the cost responsibility associated with self-consumption.[330] While the NUS charge calibrates cost responsibility to customer size, seasonal usage patterns, and actual self-consumption, the minimum bill is typically set to a single level across an entire service territory. This single level is not an accurate method of assigning many types of shared costs to customers that range from coastal apartment dwellers with small quantities of usage to large households in hot inland areas that may use thousands of kilowatt-hours per month. As explained by NRDC witness Chhabra, "it's hard to make it progressive" because the same minimum amount is applied to customers from different income levels and home sizes.[331]

[329] Ex. TRN-3, page 47, footnote 103. TURN is challenging some of these securitization proposals in other proceedings and does not concede that the amounts proposed by the IOUs are reasonable. However, any costs approved by the Commission (and surviving judicial review) should be collected fairly from all customers.
[330] RT Vol. 10, page 1663, Chait.
[331] RT Vol. 10, page 1864, Chhabra.

The adoption of a higher minimum bill would likely incentivize customers to size new generation to ensure a sufficiently large resulting average monthly bill to avoid triggering any minimum bill threshold. Calibrating system size to avoid a minimum bill would not resolve the cost shift but instead provide strategies for gaining maximum bill savings from onsite generation without incurring any additional expenses from the minimum bill. The result would be that smaller customers face greater barriers to installing onsite generation than larger customers since the minimum bill would be identical for both customers. For smaller customers with onsite generation, a high minimum bill could also disincentivize conservation and efficiency since a portion of the resulting savings may not be realized.

The Commission has previously considered the benefits and drawbacks of higher minimum bills for all residential customers. In D.20-03-003, the Commission authorized some modifications to the minimum bills of all three IOUs but cautioned "it is important to note that a minimum bill would not necessarily satisfy other rate design principles addressed by a fixed charge, such as communicating to the customer the customer-specific costs they impose on the IOU."[332] In D.15-07-001, the Commission noted that "because minimum bills apply only to that percentage of customers whose usage is less than the minimum kWH of usage, the minimum bills collect less revenue to contribute to fixed cost recovery."[333]

If the Commission wishes to consider higher minimum bills for successor tariff customers, the size of the minimum bill should be scaled to account for customer size and/or the amount of installed generating capacity. This scaling could promote better parity between customers of different sizes and ensure that a minimum bill collects system costs fairly from all users rather than targeting small users or those with oversized generating systems.

[332] D.20-03-003, page 36.
[333] D.15-07-001, page 218.

3. *Market Transition Credit proposals by other parties are less developed and cannot easily accommodate external funding sources*

TURN testimony outlines a specific approach to developing a Market Transition Credit (MTC) that can be provided to successor tariff customers as an up-front, one-time subsidy payment designed to achieve a defined payback period.[334] TURN's MTC proposal represents an important tool that the Commission can use to transparently promote behind-the-meter successor tariff generation under all future drivers of adoption, accommodating changes in capital costs, operating costs, income tax, finance costs, electricity rates and incentives. The MTC can also be used by the Commission, in conjunction with TURN's successor tariff proposal, to establish any glidepath the Commission desires, ensuring that successor tariff implementation achieves Commission penetration objectives, while at the same time ensuring that participants are not over-compensated in later years. Importantly, the MTC can be structured in a manner that allows it to be funded with sources external to rates.

A few parties incorporate an MTC into their tariff proposals. NRDC endorses an up-front MTC calibrated to achieve a 10-year payback with a reliance on sources of non-rate funding.[335] Sierra Club refers to their export compensation proposal as including an MTC that would be paid for 20 years but does not attempt to separately identify the MTC amounts or to distinguish it from the base export compensation.[336] CCSA proposes an MTC for community solar projects.[337]

The Joint IOUs endorse an Income-Qualified Discount (IQD) for low-income customers that would provide a reduction in the applicable Grid Benefits Charge designed to enable the customer to realize a forecasted payback period (with an illustrative duration of 10 years proposed for PG&E customers).[338] This proposal functionally operates as an

[334] Ex. TRN-1, pages 51-56.
[335] Ex. NRD-1, page 19
[336] Ex. SCL-1, page 26
[337] Ex. CCS-1, pages 31-38. TURN addresses this proposal in Section V(C)(4).
[338] Ex. IOU-1, page 169

MTC provided over a fixed duration to achieve a specific adoption objective. The IOU proposal, however, would be funded entirely through rates and is not designed to accommodate external funding sources.

TURN's MTC proposal represents the best option for adoption by the Commission because it is narrowly tailored to address adoption by any defined customer subgroups, allows the funding to directly reduce up-front system installation costs, increases confidence in the expected payback period for a participating customer, can adjust to changing input assumptions (tax credits, retail rates, financing costs, system costs, forecasted ACC values), provides transparency, and can be structured to accommodate funding from non-rate sources. These elements should be embraced by the Commission as part of any successor tariff design that is consistent with the guiding principles.

4. *Proposed low-income customer tariffs*

a. *Joint Parties Policy A and CalSSA proposals*

The Joint Parties (Grid Alternatives, SEIA/VS, Sierra Club) propose a successor tariff option for low-income customers that would provide export credits at the 2021 default residential non-CARE retail rate offered by the customer's IOU.[339] The rate would be vintaged for 20 years while maintaining the CARE or FERA discount on energy imports.[340] CalSSA proposes to allow low-income customers in single-family residences to remain on the existing NEM 2.0 tariff with exports credited "at the undiscounted, otherwise applicable retail rate".[341]

TURN does not support an approach that continues the basic NEM 2.0 structure for CARE and FERA customers as long-term solutions and end-state rates. While TURN does support the Joint Recommendation for an interim tariff that would provide undiscounted retail rates (net of nonbypassable charges) as export compensation to

[339] Ex. GRD-1, page 3.
[340] Ex. GRD-1, pages 2-3.
[341] Ex. CSA-1, page 22.

CARE customers, this transitional approach should be limited to the short window prior to the implementation of end-state tariffs.[342] For purposes of transitional rates, TURN proposes to require participants to migrate to end-state tariffs after either 10 years (SDG&E) or 15 years (PG&E and SCE) rather than the 20-year period proposed by CalSSA and the Joint Parties.

The continued use of a NEM 2.0 structure, as proposed by CalSSA and the Joint Parties, is problematic for six reasons. First, the crediting of self-consumption at retail rates fails to adequately collect nonbypassable, unavoidable and shared costs. Second, any tariff that allows self-consumption quantities to be credited at retail rates for all successor tariff customers would perpetuate economic discrimination against low-income customers by providing a lower credit for self-consumption (the discounted CARE/FERA rate) than would be provided to higher income customers (undiscounted non-CARE rates).[343] Third, providing compensation for self-consumption at lower CARE retail rates and exports at higher non-CARE rates is not cost or value based. This difference in compensation is not justified by any objective measure of the benefits provided by the generation to the grid and all customers.

Fourth, the retail rate credit does not accurately value exports. As explained in Section V(C)(1), there is no correlation between retail rates and the adopted avoided cost values that reflect the benefits of the generation to the grid and all customers. Fifth, the CalSSA proposal would allow export compensation to rise over time based on increases in non-CARE rates, a linkage which would result in ongoing cost shifting throughout the life of the tariff. Sixth, the Joint Parties propose to freeze current TOU period definitions applicable to export compensation for a period of 20 years.[344] This approach would

---

[342] The transitional tariff also requires participation in an electrification rate and, for purposes of export compensation, reduces the retail rate by the nonbypassable charges recognized under NEM 2.0 plus the PCIA. The export rate is fixed (no escalation) for the duration of the customer's participation in the tariff.
[343] Ex. TRN-3, page 65.
[344] Ex. TRN-3, page 65, *citing* Grid Alternatives response to TURN Data Request #1, Q4(a).

create a disconnect between the TOU periods used for exports and the TOU periods used for imports. This disconnect could create skewed incentives over time.

TURN's modeling of the CalSSA and Joint Parties Policy A proposals shows RIM scores that are worse than NEM 2.0 and 20-year PCT results that range from 1.3 to 1.9.[345] For SCE, 20-year IRRs range from 13% to 20%.[346] For PG&E, IRRs are approximately 16% over 20 years.[347] Similar to results for non-CARE customers, the 10-year IRRs indicate that customers have been adequately compensated by year 10. This conclusion is supported per simple payback across all scenarios that are achieved in roughly 7 years or less, and full discounted paybacks that are achieved in 8 to 12 years. The CalSSA tariff produces shorter discounted paybacks for new customer vintages with results as low as 8 years for customers initially taking service in 2025.[348]

TURN shares the goals of parties seeking to provide a better value proposition for low-income customers but believes that a superior approach involves a one-time MTC that can be used to reduce up-front financial commitments made by these customers (either in the form of a system purchase or lease) in a manner that offsets the lower credit for self-consumption realized by CARE/FERA customers. TURN's CARE customer proposal can be used to establish a payback or IRR for target customers. TURN's modeled CARE customer scenarios include a MTC with a 10-year payback and a 13-year fully discounted payback. With a MTC set to achieve a 10-year payback, the 10-year IRRs are approximately 12% and the 20-year IRRs are 18%.[349] With a MTC set to achieve a 13-year payback, the resulting 10- and 20-year IRRs are 7% and 14%,

---

[345] Ex. TRN-3, pages 82, 88-90. On page 69, TURN's rebuttal testimony incorrectly states that the modeling of the CalSSA CARE tariff does not net nonbypassable charges from the retail rate for purposes of calculating export values. In fact, TURN did make this adjustment for purposes of performing the modeling results.
[346] Ex. TRN-3, pages 88-90.
[347] Ex. TRN-3, page 91.
[348] Ex. TRN-3, page 68, Table 10.
[349] Ex. TRN-3, page 83.

respectively.[350] The Commission can adjust the MTC to achieve any target IRR or PCT result. With a MTC set to achieve a 10-year discounted payback, simple payback is achieved in 5 to 7 years. With the 13-year MTC, simple payback is achieved in 6 to 9 years.[351]

Under TURN's proposal, RIM results range from approximately 0.39 to 0.46. These results are higher than the CalSSA and Joint Parties proposals and demonstrate the ability of TURN's proposal to reduce the CARE customer cost shift, even after including the MTC. The RIM scores for TURN's CARE proposal do not reflect the use of any methods to protect non-participating customers from cost shifting including collecting a portion of MTC funds from legacy NEM customers or relying on funding sources outside of retail rates. Either of these options would materially reduce cost shifting and benefit non-participants.[352]

TURN's proposal also frontloads payments to CARE customers which would lower up-front costs and could promote utilization of lower-cost system ownership rather than leasing arrangements.[353] Instead of providing an inflated value for exports over an extended timeframe that cannot be fully utilized by the customer, the Commission should link export compensation to avoided costs and authorize up-front incentives for low-income customers.

TURN's analysis highlights the modest impacts of the CalSSA and Joint Parties proposals on key metrics versus the status quo. The Commission should find that these proposals do not constitute durable and sustainable end-state tariffs that comply with

---

[350] Ex. TRN-3, pages 88-90.
[351] Ex. TRN-3, pages 83, 88-90.
[352] Ex. TRN-1, page 75. TURN's results show RIM scores of 0.67 (PG&E), 0.79 (SCE) and 0.89 (SDG&E) if 75% of the CARE MTC costs are recovered outside of rates. The Commission should recognize that collecting these amounts from legacy NEM customers would practically have the same effect for the cost shift to non-participants.
[353] Ex. TRN-3, page 68.

the guiding principles. Any use of a modified NEM 2.0 structure for low-income customers should be limited to a transition period, allow new enrollees to take service for no longer than 10-15 years, incorporate a broader range of nonbypassable charges (including PCIA) and require participation in a suitable electrification rate. Once the transition period is complete, all new low-income customers should enroll in a tariff that has the features and design elements proposed by TURN.

b. Joint IOU and Cal Advocates proposals

The IOUs and Cal Advocates both propose to provide low-income successor tariff customers with a discount on the applicable Grid Benefits Charge (GBC) applied to non-CARE customers. The IOUs would reduce the GBC for a duration sufficient to achieve a forecasted payback and Cal Advocates would permanently exempt CARE and FERA customers from any such charges.[354] These proposals effectively provide these GBC reductions as an MTC provided over time.

While TURN appreciates these proposals, they are inferior to TURN's proposed approach for several reasons. First, the total expected value associated with an exemption or reduction in GBCs would be difficult to forecast for typical low-income successor tariff customers because it is paid out over time rather than upfront.[355] The uncertainty associated with this value would frustrate the ability of low-income customers make financial commitments to new behind the meter generation. By comparison, TURN's proposed MTC would provide an identified up-front incentive that would directly offset the initial financial commitments made by a customer and allow the customer to lock into 10-year export rates. Cal Advocates also proposes an up-front MTC but the value is significantly smaller due to their reliance on retail rates to provide compensation for self-consumption and the longer assumed payback period.[356] TURN's approach would provide far greater confidence that the customer will receive

[354] Ex. IOU-1, page 169; Ex. PAO-1, page 3-52
[355] Ex. TRN-3, page 69.
[356] Ex. PAO-1, pages 3-56, 3-68.

the expected benefits over the payback period used to set the MTC while mitigating excessive cost shifts.

Second, the reduction or elimination of GBCs would result in compensation for self-consumption at levels closer to retail rates.[357] Creating a large price differential between compensation for self-consumption (levels close to retail rates) and exports (ACC-based values) does not align the tariff with the benefits provided by the generation to the grid and all customers. By comparison, TURN's proposal would provide credit for self-consumption at generation rates and export compensation using ACC values. TURN's approach better aligns compensation for actual generation with the value it provides to the grid.

The E3 modeling of these proposals shows roughly comparable results among these proposals with respect to payback periods, first year cost shift, PCT and RIM.[358] By comparison, TURN's proposal would yield shorter payback periods and more predictable benefits for participating CARE customers.

D. <u>Additional charges for legacy NEM customers</u>

1. NRDC proposal to charge legacy NEM customers

NRDC proposes an equity fee to support an equity fund used "to bring clean energy benefits to qualifying low-income customers".[359] The charge would be applied to existing non-CARE residential customers served under legacy NEM tariffs and to non-CARE customers starting 10 years after taking initial service under the new successor

---

[357] Ex. TRN-3, page 70; The Cal Advocates proposal would result in compensation for self-consumption at retail rates. The Joint IOUs would continue to assess a fixed charge and a portion of the GBCs on CARE/FERA customers.
[358] Ex. TRN-3, page 70, E3 Updated Cost-effectiveness analysis, June 15, 2021, page 55
[359] Ex. NRD-1, page 21.

tariff. The monthly fee would be initially set at $2.50/kW-dc of installed solar capacity and would be revisited every two years.[360]

TURN supports NRDC's proposal to establish a charge on legacy NEM customers that could fund new clean energy technology adoption by low-income customers. TURN recommends that all proceeds from this charge be applied to the costs of providing an MTC to new low-income successor tariff customers. This use of the equity fee proceeds would be appropriate because it would reduce any MTC cost obligation for all other customers (including low-income customers without behind the meter generation). This approach would be consistent with TURN's recommendations.

2. *Cal Advocates proposal for Equity Charge*

Cal Advocates proposes an Equity Charge on legacy NEM customers to accomplish two objectives. The first objective is to provide an up-front rebate to new CARE successor tariff customers sufficient to equalize the payback period between a CARE and Non-CARE customer.[361] The second objective is to increase participation in existing programs designed to benefit customers in Disadvantaged Communities.[362] The total equity charge proposed by Cal Advocates would range between $3.29-$3.49/kW of installed legacy NEM solar.

TURN supports the collection of additional funds from legacy NEM customers to promote the incremental adoption of distributed resources by low-income customers.[363] However, TURN would exempt existing CARE NEM customers from paying any equity charge. Moreover, TURN proposes to use all the funds collected from legacy NEM customers for the MTC provided to new CARE successor tariff customers. This approach could be coordinated with existing programs to promote solar adoption in

[360] Ex. NRD-1, page 21
[361] Ex. PAO-1, page 3-56
[362] Ex. PAO-1, page 3-59
[363] Ex. TRN-3, page 62.

DACs and ensure that sufficient up-front rebates are provided to participants to achieve specific program objectives.

E. Community Solar Virtual Net Energy Metering proposal

CCSA proposes a community solar tariff that would apply to solar projects up to 5 MW in size located behind a customer meter taking retail service at the distribution level.[364] Projects would receive compensation for exported energy that can be assigned to individual subscribers located anywhere within the same IOU service territory. Subscribers would not be required to make any minimum commitment. Export compensation for the project would be determined using 25-year levelized values for non-energy supply components of the ACC and actual hourly day ahead CAISO market prices for the energy supply component.[365] Subscriber bill credits would be based on the value of exported energy from the generator account.[366]

Because subscribers would be charged for all their onsite usage based on applicable retail rate tariffs, there would be no need to assess an NUS charge, GBC, or other fixed charge to address cost shifting concerns.[367] The fact that larger projects would participate should produce better cost test results under the TRC because the installed generation costs (on a $/kW basis) are expected to be significantly lower than for small residential rooftop systems and systems are expected to be oriented more optimally.[368] In addition, compensating all generation output based on avoided cost values should produce high RIM values and minimize any cost shifting to non-participants. Moreover, the availability of a community solar tariff for new residential construction would

[364] Ex. CCS-1, pages 2-3
[365] Ex. CCS-2, page 4
[366] TURN assumes that CCSA's tariff would not allow these projects to offset onsite load at the generator account location and receive full retail rate credits.
[367] The primary cost shifting concern is related to the costs of billing and collections (including uncollectibles) that CCSA proposes would be administered by the IOU.
[368] The only factor driving an offsetting increase in costs would be requiring the IOU to administer the crediting system and act as a collection agent for the generation owner or generator account.

satisfy the alternative compliance approach under the Title 24 New Solar Home Program and should be able to demonstrate cost-effectiveness.[369]

Based on these strengths, TURN believes that CCSA's proposal has merit and should be adopted by the Commission subject to several modifications that would need to be incorporated as part of a subsequent implementation phase.[370] This phase should review key program elements and involve a range of stakeholders to determine reasonable parameters that address the legitimate interests of subscribers, project developers and non-participating customers.

TURN offers five modifications to the CCSA proposal. The first four are as follows:

- CCSA proposes to set export compensation for the non-energy components of the ACC based on 25-year levelized values using the most recent ACC update.[371] For the reasons explained in Section V(C)(1)(b), TURN does not support a 25-year levelization of any portion of ACC values.[372] Instead, TURN believes that the non-energy components of the ACC could be subject to a 10-year lock in similar to the approach proposed under TURN's successor tariff proposal.

- CCSA does not propose that the terms and conditions of customer contracts be subject to review and potential modification by the Commission. Instead, CCSA offers that project developers would be obligated to submit standardized disclosures to the Commission as a condition of registration and that certain

[369] RT Vol. 10, page 1719, Smithwood; Ex. TRN-12, SMUD Neighborhood SolarShares Program application (revised), page 6, footnote 1; Pursuant to Section 10-115 of the 2019 Building standards, the Energy Commission may approve a community shared solar system as a compliance option to partially or totally meet the onsite solar generation that would otherwise be required by Section 150.1(b) of Title 24.
[370] Ex. TRN-3, pages 57-60, 74-76
[371] Ex. CCS-2, page 5.
[372] This opposition is driven in large part by the highly speculative nature of later year values in a 25-year forecast.

practices (use of FICO scores, exit fees for low-income customers) would be prohibited.[373] TURN believes that additional Commission oversight may be appropriate, particularly at the outset of the program given CCSA's proposal to use the IOUs as collection and billing agents. For example, TURN believes that there may be value to standardizing certain contract terms to prevent deceptive practices.

- CCSA did not originally propose any particular treatment of Renewable Energy Credits (RECs) associated with exported energy.[374] If the project owner makes any representations to subscribers regarding the environmental or renewable attributes of the energy (*e.g.* "GHG free", "renewable", "solar"), all RECs associated with energy credited to a customer account should be retired on behalf of the subscriber.[375] When RECs are retired in this manner, they cannot be traded to another market participant or used by the project owner or the utility to meet a compliance obligation. This treatment prevents any double counting of these environmental and renewable attributes. During hearings, CCSA witness Smithwood agreed that all RECs associated with energy credited to a subscriber account should be retired on behalf of the subscribers.[376] The Commission require this treatment for all RECs produced by a community solar project.

- CCSA envisions a model in which subscribers enter into short-term offtake contracts, make no up-front investment and do not take ownership shares in the project.[377] TURN believes that the Commission should investigate the development of program elements that would promote ownership shares

---

[373] Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q5
[374] Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q3 ("CCSA does not address RECs in its proposal. Any treatment of RECs could be addressed in the standardized consumer disclosure form to ensure customers are aware of what claims they can make; this is the practice in most states with community solar programs.")
[375] Ex. TRN-3, page 76.
[376] RT Vol. 10, page 1719, Smithwood.
[377] RT Vol. 10, pages 1721-1722, Smithwood.

options and allow the subscribers to realize the full economic benefits of their investment (rather than just receiving a bill credit that is structured as a percentage of their monthly payments).

TURN's fifth and most significant concern with CCSA's proposal involves the authorization of a Market Transition Credit (MTC) for projects located in Environmental Justice and Low Income communities. CCSA proposes that an MTC be provided to any facility located within a disadvantaged community where at least 50% of the capacity is subscribed by low-income customers (CARE/FERA).[378] The total value of the MTC for a project would be calculated using a "cents-per-kWh credit adder" above the basic avoided cost export rate for a period of 25 years and provided as a one-time up-front subsidy to the project developer or on an ongoing basis to the generator and the subscribers.[379] The level of the MTC would be set, in combination with avoided cost export rates, to reflect the applicable retail rate for each IOU at the time the project goes into service and thereby approximate the retail rate compensation provided under a traditional NEM tariff. CCSA further suggests that the entire MTC budget should be "ratepayer funds or funds otherwise under the immediate control of the PUC."[380]

Although TURN supports using a ratepayer-funded MTC to provide access to community solar by CARE customers, the approach proposed by CCSA is problematic. TURN does not believe that the MTC should be set to effectively compensate community solar projects at retail rate levels.[381] There has been no showing that retail rate levels are the appropriate benchmark for enabling project financing or achieving

---

378 Ex. CCS-1, page 33. CCSA does not clearly require any portion of the subscribers to live within the same, or another, disadvantaged community.
379 Ex. CCS-1, pages 33, 36-37; Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q7.
380 Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q8.
381 Ex. TRN-3, page 59; CCSA would set the MTC at the difference between the 25-year ACC values for a particular project and the current retail rates in effect for each IOU.

any level of assumed customer adoption. Given the lower cost of these projects, and the excessive cost shifting that would result, there is no basis for this level of subsidization. The Commission should consider a more appropriate MTC value that is calibrated to achieving defined and transparent metrics relating to payback (*e.g.* 10 year discounted), bill savings and IRRs.

Moreover, CCSA proposes that only 50% of the capacity would need to be subscribed by low-income customers for the entire project to qualify for an MTC.[382] The remaining portion of the project receiving an identical MTC could be subscribed by higher-income residential customers or even commercial/industrial customer accounts. As a result, up to half of the MTC for a given project would be provided for customers that do not demonstrate any need for this level of subsidy such as higher income residential customers, commercial customers, and large corporate retail chains. TURN does not support using scarce ratepayer funds to provide large new subsidies without more appropriate constraints on eligibility.

CCSA does not propose any minimum duration for the commitments made by "benefiting accounts" that subscribe to the project offtake.[383] Yet CCSA would apply the 50% low-income customer capacity subscription threshold on an ongoing basis, which means that expiring customer contracts could leave projects with less than 50% low-income subscribers over the course of the project life.[384] During hearings, CCSA witness Smithwood indicated that, if such an event occurs, project owners could be subject to penalties or other remedies over time but could not provide specifics.[385] Since these remedies could potentially result in a low-income subscriber losing their MTC based on the project developer's failure to remain in compliance, the absence of a defined mechanism to address this potential outcome is problematic.

---

[382] RT Vol. 10, pages 1711-1712, Smithwood.
[383] Ex. CCS-1, page 20.
[384] RT Vol. 10, page 1716, Smithwood.
[385] RT Vol. 10, page 1716, Smithwood.

CCSA would also permit up to 50% of the MTC value to be retained by the project developer rather than being passed through to subscribers.[386] Given the sizeable MTC values proposed by CCSA (between 4.4 and 16.2 cents/kWh depending upon the IOU), and the total amount of ratepayer funding required (up to $7.6 billion over 25 years), it is not reasonable to allow project developers to retain up to 50% of these subsidies.[387] Although CCSA witness Smithwood agreed during hearings that this credit is not intended to unfairly enrich developers, CCSA does not propose any other limits or criteria that would prevent project developers and their investors from keeping excessive amounts of ratepayer funds.[388] TURN cannot support making a large amount of ratepayer funding available to developers without a clear demonstration that low-income subscribers would receive maximum value and project owners could not unreasonably retain funds to benefit investors.

Finally, CCSA's proposal is estimated to cost $7.6 billion over 25 years (or $3.7 billion in up-front funding).[389] TURN has concerns about authorizing this level of ratepayer subsidy for community solar projects absent a showing that the funds are needed to support a specific level of project development, that the amounts are tailored to achieve defined customer payback assumptions that take into account the costs of the project, and that all MTC amounts will be credited to customers.[390]

Despite these concerns, TURN believes that it is possible to structure an MTC to support community solar projects. During hearings, CCSA witness Smithwood indicated a willingness to explore "different formulations" for the MTC and to consider

[386] Ex. CCS-1, page 38; RT Vol. 10, page 1713, Smithwood.
[387] Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q7 (attachment).
[388] RT Vol. 10, pages 1714-1715, Smithwood.
[389] Ex. TRN-4, Attachment C, CCSA response to TURN Data Request #2, Q7 (attachment). Assumes 2021 ACC values.
[390] Ex. TRN-3, pages 59-60.

other related concerns raised by TURN.[391] Based on these statements, TURN believes that the development of an MTC to support community solar projects should be addressed in a subsequent implementation phase of this proceeding. In that phase, the Commission should consider whether to limit MTC eligibility to low-income customer subscriptions, whether to set the MTC to achieve a specific discounted payback target, and the extent to which the MTC should be provided to subscribers or project developers. These issues can be considered as part of a more deliberate process to ensure that the structure of any adopted program is calibrated to achieve best results for both subscribers and the general body of ratepayers.

While TURN believes that the CCSA concept requires additional work, the core concept is worthy of additional consideration and development in a subsequent phase of this proceeding. TURN urges the Commission to endorse the CCSA concept and authorize additional consideration of key program details.

F. <u>Timeline and Process for Implementation</u>

Both the November 19, 2020 Scoping Memo and the January 28, 2021 ALJ Ruling request that parties submitting successor tariff proposals identify their implementation plans and expected timelines.[392] The adoption of TURN's successor tariff, or a modified version thereof, requires a formal implementation phase to resolve several remaining issues. Depending upon whether the Commission adopts TURN's proposal in whole, or in part, the following issues would need to be resolved in additional phases of this proceeding:

- Approval of inputs to methodology for calculating and updating the Market Transition Credit based on a defined target payback period for CARE customers

[391] RT Vol. 10, page 1715, Smithwood.
[392] ALJ January 28 Ruling, Instruction #4; Joint Assigned Commissioner Scoping Memo and Administrative Law Judge Ruling Directing Comment on Proposed Guiding Principles, November 19, 2020, pages 2-3

and any other eligible customer groups. Relevant inputs include assumed installed generation cost, forecasted bill savings, discount rate, tax benefits and incentives, finance costs, and other key variables.

- Clarification of customer eligibility for MTC incentives, approval of methods for recovering MTC costs and consideration of non-rate options for financing MTC incentives over time.

- Clarifications to the methodology for calculating Nonbypassable, Unavoidable and Shared costs to be collected from NEM customers for self-consumption quantities.[393]

- Rules governing the calculation of estimated production from BTM generation for purposes of calculating self-consumption quantities assessed NUS costs.

- Approval of export credit methodology that relies on ACC values and in the future can accommodate CAISO day-ahead hourly market prices.

- Establishment of technical requirements for paired storage units to dispatch in response to system emergencies and severe stress conditions, compensation amounts for such services, and whether storage discharge must be limited to customer load.

Based on identified concerns about the timeline for implementation raised during evidentiary hearings, TURN offers a revised proposal that differs from the one contained in testimony. Recognizing the need for time to fully address any implementation challenges, TURN recommends that the Commission proceed in three

[393] These clarifications would be necessary if the Commission finds that some, but not all, portions of transmission, distribution or nonbypassable charges should be assigned to self-consumption quantities.

distinct phases. These phases will allow for immediate reforms to the existing successor tariff and permit sufficient time to develop the elements of an "end-state" tariff that will go into effect as soon as possible but no later than January 2024. The three phases should occur as follows:

> <u>Phase 1</u> – implementation of the interim tariff outlined in the Joint Recommendations. All new customers enrolling in net metering should be required to take service under this tariff and may remain on it for a period of up to 15 years (or 10 years for SDG&E customers).
>
> <u>Phase 2</u> – Refinements to key elements of the "end-state" successor tariff including MTC, NUS charge, updated ACC values (through ongoing ACC update process), estimated generation, and billing system modifications to accommodate end-state successor tariff. The revised tariff should be operational by January 1, 2024 for all new enrollments.
>
> <u>Phase 3</u> – Development of remaining enhancements to the end-state tariff including day-ahead pricing elements for energy supply components of ACC and the ability to signal and bill such prices, instantaneous netting (if not implementable prior to January 1, 2024) and communication/dispatch protocols for paired storage, additional paired storage rate structures and compensation for calls during CAISO Stage 2 emergencies. These elements should be incorporated into the end-state tariff by December 31, 2025.

If the Commission provides clear and decisive guidance through a final decision in this phase, a transitional tariff could be implemented promptly with minimal need for delay. The remaining open issues could be primarily resolved through a collaborative process that involves working groups or as part of a formal process involving comments. The informal process involving working groups would be composed of key stakeholders and would produce a report that addresses recommended implementation details relating to Phase 2 (and subsequently for Phase 3). This report would be subject to comment by all parties. Following comments, the Commission would issue a Decision resolving all remaining issues.

A possible timeline for this process is as follows:

Transitional tariff process	
Submission of IOU advice letters (transitional tariff)	*+ 30 days*
Commission approval of transitional tariff Advice Letters	*+ 60 days*
Total implementation timeline for transitional tariff	*= 90 days*
Phase 2 process (concurrent with transitional tariff process)	
Phase 2 processes (formal and informal)	*+ 12 months*
Commission approval of End-state tariff design	*June 2023*
IOU advice letters implementing end-state tariff	*August 2023*
Availability of end-state tariff	*January 1, 2024*
Phase 3 process	
Commencement upon completion of Phase 2	*June 2023*
Phase 3 processes	*+ 18 months*
Commission approval of Phase 3 issues	*Early 2025*
IOU advice letters implementing Phase 3 issues	*Mid 2025*
Availability of Phase 3 end-state tariff enhancements	*December 31, 2025*

This timeline assumes that the Commission adopts TURN's proposal. It is not possible to provide a schedule of subsequent implementation activities if the Commission adopts a hybrid of multiple tariff proposals, seeks to incorporate other tariff elements that are not fully fleshed out, or relies on other proceedings to develop new rate tariffs. Moreover, TURN recognizes that utility billing system limitations may affect the overall implementation timeline.

VI. CONCLUSION

For the reasons outlined in the previous sections, TURN urges the Commission to embrace a significant course correction with respect to NEM tariffs that fairly balances the interests of participants and non-participants. TURN's successor tariff provides a framework and the tools to accomplish all the objectives outlined in the Guiding Principles.

Respectfully submitted,

MATTHEW FREEDMAN

____________/S/___________
Attorney for
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: August 31, 2021

APPENDIX A

JOINT RECOMMENDATIONS OF THE INDEPENDENT PARTIES FOR A SUCCESSOR TARIFF TO THE CURRENT NET ENERGY METERING TARIFFS

The below groups, representing a diverse array of independent voices, provide the following set of Joint Recommendations to resolve the issues in Rulemaking (R.) 20-08-020. The groups recommend the California Public Utilities Commission (Commission) adopt these Joint Recommendations to effectively reform the current Net Energy Metering (NEM) tariffs. The Joint Recommendations span essential policies, export compensation, a Grid Benefit Charge, equity provisions, transition of legacy NEM 1.0 and 2.0 customers, and an interim tariff designed to make immediate progress on reducing the NEM cost burden until the successor tariff can be implemented in full.

The below groups recommend the Commission adopt the following sections of the Joint Recommendation.

Organization	Support for Specific Sections of Joint Recommendations
Public Advocates Office (Cal Advocates)	Sections 1-6
Natural Resources Defense Council (NRDC)	Sections 1-6
Coalition of California Utility Employees (CUE)	Sections 1-3, Sections 5-6
California Wind Energy Association (CalWEA)	Sections 1-3, Sections 5-6
The Utility Reform Network (TURN)	Sections 1-3, Sections 5-6
The Independent Energy Producers Association (IEPA)	Section 1-4, Section 5 Part 1 and Part 2a, Section 6

SECTION 1
ESSENTIAL POLICIES FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on the NEM successor tariff should include the following fundamental policies:

- Fairly compensate successor tariff customers for the benefits of clean energy without unduly raising electric bills for non-participating customers by valuing successor tariff customers' exported energy using the most current Commission-approved Avoided Cost Calculator. The successor tariff should utilize net billing, which means one bill that separates compensation for exports, using a value that differs from the retail rate, and charges for consumption.

- Require successor tariff customers to pay their fair share for grid use by implementing a Grid Benefits Charge (GBC) to recover costs for transmission, distribution, non-bypassable charges, and any other shared system costs.

- Support lower income customers by protecting them from undue cost burden as a result of the existing or successor tariffs. Provide lower income customers with assistance to overcome structural barriers to adopting distributed energy resources.
    - Any incentives should be prioritized for lower income customers and should be provided upfront to reduce the initial system cost.
    - Transparently identify any subsidies to successor tariff customers and collect them, to the maximum extent possible, from sources other than utility rates.

- Transition existing NEM 1.0 and 2.0 non-California Alternate Rates for Energy (CARE) and non-Family Electric Rate Assistance (FERA) customers in a way that quickly decreases and eventually eliminates the NEM cost burden while ensuring a payback of the NEM customer's system cost over a reasonable period of time.

When developing different components of the successor tariff, the Commission should ensure the components interact in a manner that satisfies the essential policies outlined here.

SECTION 2
EXPORT COMPENSATION FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on export compensation for the NEM successor tariff should include the following:

- Instantaneous netting or, if that is not possible, hourly netting to determine the (1) monthly quantity of electricity exported from the customer's premise to the grid and (2) the time periods at which these exports are made.
- Exported electricity should be compensated based on avoided costs, as calculated by the Commission's Avoided Cost Calculator (ACC).
- Avoided cost-based export values should be updated annually on January 1
- To avoid potentially large swings in export compensation levels due to different ACC versions, export values should be based on the two most recent Commission-adopted ACC versions.
- Export compensation rates should be differentiated either hourly or, at a minimum, by Time-of-Use (TOU) period to provide appropriate compensation for exported electricity and thereby also incentivize paired storage systems operation to support grid needs (e.g., charge during off-peak and discharge during on-peak periods).
- Export compensation should be structured to provide customers with the option to obtain predictable values for a defined period of time. There are two ways to provide this certainty:

    (1) Develop export compensation based purely on the ACC. Customers get locked-in to a predictable avoided cost-based export compensation for a period of up to 10 years (based on the recommended methodology to provide a stable export compensation signal described below).
    (2) Lock-in all avoided cost values except avoided energy costs.[1] The avoided energy costs will be taken from the day-ahead or real time-market.

    - Explanation – Although the use of ACC energy cost forecasts will provide a more stable signal, tying a portion of export compensation to the day-ahead or real-time market would better align with observed avoided energy supply costs, and it would provide a more accurate signal and allow customers to receive higher payments during periods of supply scarcity (when electric prices are very high). Each method has its advantages. The joint recommendations are agnostic on which of these are chosen, i.e., tying the avoided energy cost component of the export compensation purely to the values in the ACC or to the day-ahead or real time market.

[1] The avoided energy cost is a specific component of the ACC's avoided costs that is linked to the costs of procuring energy (kWh) from CAISO wholesale energy markets.

- To provide more certainty to customers considering installation of a behind the meter (BTM) generation system, the initial export compensation may be locked in for up to 10 years.[2] After the lock-in period, export compensation rates should be updated annually on January 1 using the method described above.
    - Because successor tariff customers may lock-in export values for several years, the export value should be based on the estimated ACC values for all years associated with the lock-in period.[3] If fixed levelized values are used rather than the forecast values for each future year in the ACC, the levelized values should not be based on forecasts beyond the next four consecutive years.[4]
    - The lock-in export vintage should be determined by the calendar year that a customer submits a complete Interconnection Request. For example, a customer who submits a complete Interconnection Request in 2022 should receive the export rate adopted on January 1, 2022 (based on the 2020 and 2021 ACCs), even if the BTM system doesn't receive permission to operate until 2023.
        i. The lock-in period for each customer should start on January 1 of the calendar year in which they receive permission to operate. The lock-in period for customers who receive permission to operate on or after July 1 will begin January 1 of the following year. For example, assuming a five-year export compensation lock-in, a customer who interconnects on July 1, 2022, would receive the locked-in exports rates until December 31, 2027. This provision will ensure that all customers will have the opportunity of benefitting from the adopted lock-in period plus or minus six months.
    - The TOU or hourly export values, with the possible exception of the avoided wholesale energy costs, should be fixed for the duration of the lock-in period.[5]
    - When determining a lock-in period, the Commission should ensure the different components of export compensation interact with each other and

[2] Parties provide their recommendations for a specific lock-in duration (up to 10 years) in briefs.
[3] For example, if a customer joins the successor tariff in 2023, their export compensation rate in 2026 would be the 2022 version ACC forecast for 2026.
[4] For example, a peak TOU export compensation rate for a BTM generation system that completes interconnection in 2021 would be averaged using TOU peak avoided costs over 2022-2025 from the 2019 and 2020 versions of the ACC.
[5] For example, with a five-year lock-in period the TOU export compensation rates for a BTM generation system that submits an Interconnection Request in 2021 and receives permission to operate before July 1, 2021, would be based on the levelized avoided costs over 2021-2025 from the 2019 and 2020 versions of the ACC.

other aspects of the successor tariff in a manner that satisfies the principles outlined in Section 1.

SECTION 3
GRID BENEFITS CHARGE FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should include a Grid Benefits Charge (GBC) with the following aspects:

- Successor tariff customers should pay a GBC that includes transmission and distribution costs of service, as well as the non-bypassable charges (NBCs) described below, to fairly recover shared system costs that are currently unpaid by NEM customers.
- For GBCs that are denominated on a $/kW of installed BTM capacity basis, the final GBC amounts should fall within the following range:
    - Lower end of $6.37 – $8.32/kW.[6] Distribution and transmission components from Cal Advocates and certain NBC components from TURN; and
    - Upper end of $10.24 – $14.13/kW.[7,8] GBCs proposed by the joint IOUs that are estimated by valuing all BTM production at avoided costs.
- The GBC should be based on successor tariff customers' BTM system size, energy production or portion of production consumed onsite.
    - Since certain NBCs are required to be collected based on usage, all NBCs should be assessed on a volumetric basis. The NBC charges should apply to customers' total on-site electricity consumption, which is the sum of measured imports, using either instantaneous or billing interval netting, and the electricity simultaneously produced and consumed onsite, which is equal to total generation minus exports.
    - Successor tariff customers should be given two choices to measure BTM system generation: installation of a separate, utility-grade meter to track on-site generation during each billing cycle, or the use of an engineering estimate of the total monthly on-site generation of the customer's BTM system.
- The GBC should include the following NBCs, at a minimum:
    - Public Purpose Programs (PPP);
    - Wildfire Fund Charge;
    - Nuclear Decommissioning;
    - Competition Transition Charge (CTC);
    - Reliability Services (RS);
    - New System Generation Costs (NSGC);

---

[6] The lower end should be $6.37/kW for San Diego Gas & Electric Company (SDG&E), $8.23/kW for Southern California Edison Company (SCE), and $8.32/kW for Pacific Gas and Electric Company (PG&E).
[7] The upper end should be $14.06/kW for SDG&E, $10.24/kW for SCE, and $14.13/kW for PG&E. From Joint IOUs Opening Testimony.
[8] These values do not include the Energy Resources Recovery Account costs or the PG&E wildfire securitization costs, which should also be added.

    - Investor-Owned Utility (IOU) securitization costs relating to wildfires or other undercollections;
    - Energy Cost Recovery Account (for PG&E); and
    - PUC Reimbursement Surcharge.
- The GBC may include the additional NBC:
    - Power Charge Indifference Adjustment (PCIA).[9]
- The GBC for non-residential customers should include at least the NBCs listed above. The Commission should require the utilities to propose reforms in the next rate design phases of utility General Rate Cases (GRC2s) or Rate Design Window (RDW) proceedings to look specifically at GBCs for non-residential customers.
- Because all electricity generated by Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEM-A) systems is treated as exports to the grid, the GBC should not be levied on benefitting accounts in VNEM and NEM-A arrangements, except for any NEM-A residential account with generation behind the meter.
- Please refer to Section 4 for additional exemptions to the GBC.

[9] The PCIA includes the above-market energy and capacity costs of the utilities' generation portfolios, as well as costs of utility-owned-generation assets and of managing the utilities' generation portfolios, that were incurred on behalf of all customers including successor tariff participants. Adoption of distributed generation does not reduce any of these legacy procurement costs. It would be consistent with the principles of cost causation and equitable allocation of shared generation system costs to include the PCIA in the GBC.

SECTION 5
TRANSITION EXISTING CUSTOMERS TO THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should adopt the following policies to transition existing NEM customers to the successor tariff to reduce the cost burden on non-participating customers:
If at any point an existing NEM 2.0 customer voluntarily switches to the successor tariff[10] on or after January 1, 2023, and until December 31, 2027, they should be given a rebate for a paired storage system.[11,12]

- The incentive level should start at a $0.20/Wh storage[13] rebate on January 1, 2023, then be stepped down 10% annually until December 31, 2027.

The Commission should also adopt a process to transition existing NEM customers who do not voluntarily switch:

- Part 1:
  a) Switch existing non-CARE/FERA NEM 1.0 and 2.0 customers to a new underlying TOU rate five years from the date of interconnection of their BTM generation systems or as soon as practicable for the IOU thereafter.
     i. This new underlying TOU rate must be non-tiered and have at least a 2:1 differential between summer weekday peak and weekday off-peak periods.[14] Eligible rates include:
        1. PG&E: EV2, E-ELEC (if adopted in PG&E's General Rate Case Phase 2 Proceeding[15]);
        2. SCE: TOU-D-PRIME; and

---

[10] If the Commission adopts an interim tariff, the customer should be transitioned to the successor tariff's end-state.
[11] NEM 1.0 customers should be excluded from this incentive program as they have received more years of payback for their BTM system. An existing NEM 2.0 customer should not be eligible for any incentive if they have already been mandatorily switched over to the successor tariff.
[12] Incented paired storage systems should follow rules already supplied by the Self-Generation Incentive Program to ensure the system maximizes grid benefits.
[13] The current SGIP Small Residential Storage incentive level is $0.20/Wh. See: https://www.selfgenca.com/home/program_metrics/ (accessed August 20, 2021). In 2020, the average incentive for residential general market customers to purchase and install storage through SGIP was $3,172.80. See "Real-Time Public Report," accessed March 5, 2021: https://www.selfgenca.com/home/resources/.
[14] Community Choice Aggregation (CCA) customers must switch to one of the eligible rates described in Part 1.a.i.
[15] See Application 19-11-019.

3. SDG&E must enact a non-tiered TOU rate that accomplishes the required 2:1 rate differential.[16] Until an applicable rate is adopted, customers should transition to DR-SES or EV-TOU/EV-TOU2.

ii. The IOUs should be required to perform a marketing and outreach campaign at least 3 months in advance of any rate switching. Customer marketing and outreach shall include information on technologies and available incentives that can improve system value such as heat pump water and space heaters, electric vehicles, and batteries. In addition to potential operational cost savings from electrification and load shifting technologies, materials shall also explain the climate benefits of electrification and how utilizing energy during periods of mid-day solar generation and limiting evening usage reduces climate and air pollution.

b) Rate switching shall begin no later than January 1, 2023, at which point all existing non-CARE/FERA NEM customers that interconnected in 2017 or earlier shall be moved to the new eligible TOU rate. Existing NEM customers that interconnected after 2017 shall transition to an eligible rate five years from the date of interconnection or as soon as practicable for the IOU thereafter.

- <u>Part 2:</u>
  a) Concurrent with Part 1, five years from the date of system interconnection or as soon as practicable for the IOU thereafter, apply the GBC to all non-CARE/FERA NEM 1.0 and 2.0 customers.
  b) Eight years from the date of system interconnection or as soon as practicable thereafter,[17] switch all non-CARE/FERA NEM 1.0 and 2.0 customers to the successor tariff.

The table below provides the Public Advocates Office's projected reductions in NEM cost burden of this two-part approach for the PG&E, SCE, and SDG&E territories. Part 1 was based on the simplifying modeling assumption that all NEM customers switch to TOU rates with 2:1 price differentials *in 2026*, whereas in reality many customers will be switched before then. The Part 1 estimate (9.0%) is a lower bound estimate of the cost burden reduction, and the actual reduction to the cost burden will be larger depending on how many customers switch to the new TOU rates.

---

[16] In Decision (D.) 20-03-003, the Commission directed SDG&E to propose in its next residential rate design application an opt-in, un-tiered residential TOU rate with a fixed charge that would be available to residential customers charging an electric vehicle, utilizing energy storage, or utilizing electric heat pumps for water heating or climate control. In D. 21-07-010 , the Commission specifically directed SDG&E to submit its proposal no later than September 1, 2021. This rate could potentially meet the requirements specified in the document.

[17] All NEM 1.0 and 2.0 customers will have already reached their payback period by this point.

Commission Policy Adopted	**Cost Burden Savings (in net present value)**	**Cost Burden Reduction**	**Cumulative Cost Burden Reduction**
No Reform for NEM 1.0 or NEM 2.0 customers.	$0 (out of a total $41.1 billion)[18]	0%	0%
Part 1: switching existing NEM customers to a new underlying rate five years from the date of system interconnection.	$3.71 billion[19]	9.0%	9.0%
Part 2a: applying a GBC to all existing NEM customers from the date of five years of system interconnection.[20]	$6.21 billion	15.1%	24.1%
Part 2b: switching all existing customers to the successor tariff from the date of eight years of system interconnection.	$9.51 billion	23.1%	47.3%
Offering an incentive for NEM 2.0 customers to switch to the successor tariff.	$11.97 billion[21]	29.1%	76.4%

[18] The total net present value of the cost shift over all existing customers' 20-year legacy period is $41.1 billion.

[19] This is a conservative estimate of savings as it assumes that all customers transfer to a new underlying rate in the last year of Part 1.

[20] All Part 2 modeling includes CARE and non-CARE NEM customers.

[21] This cost reduction estimate assumes that 100% of NEM 2.0 customers accept the storage rebate in first year that the successor tariff is implemented (2022). Because the share of NEM 2.0 customers accepting the incentive and the timing of the uptake are uncertain, actual reductions in the cost burden will likely be lower.

SECTION 6
INTERIM TRANSITION TO THE NEM SUCCESSOR TARIFF

Because implementing the details of the successor end-state tariff may take time, the Commission should adopt an interim successor tariff for new residential NEM customers. This interim tariff should be required for new residential NEM customers only until the end-state successor tariff rate is implemented. Within 30 days of the Commissions' final decision on a successor tariff, the IOUs should file Advice Letters to implement the interim tariff. The interim tariff should be required for new residential NEM customers within 90 days of the final decision. Key features of the interim tariff should include the following:

- Residential customers should be required to take service on an electrification rate.
- Export compensation is set at a defined percentage reduction to the Non-CARE "net" electrification retail rate at the time the interim successor tariff is enacted in 2022. The "net" electrification retail rate is the residential electrification retail rate net of the four nonbypassable charges recognized under NEM 2.0 and the Power Charge Indifference Adjustment.
- For PG&E and SCE, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve an average Participant Cost Test (PCT) result of 1.2 over a 15-year timeframe for 2022 and 2023 installations. This approach achieves a discounted payback shorter than the 15-year interim successor tariff term proposed for PG&E and SCE.
- For SDG&E, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve a discounted payback of 10 years, equal to the 10-year term proposed for the SDG&E interim successor tariff. The shorter payback period for SDG&E is due to the much higher average rates and the lack of a suitable electrification rate option.
- For both CARE and non-CARE customers, export compensation is fixed at the initial 2022 level, with no escalation over the interim successor tariff term (15 years for PG&E and SCE, 10 years for SDG&E).
- Netting period is instantaneous if practicable for the IOU. Otherwise, hourly netting should be performed.
- Customers should be allowed to remain on the interim successor tariff through the term of the interim successor tariff (15 years for PG&E and SCE, 10 years for SDG&E). The shorter duration for SDG&E is due to the accelerated payback period for these customers.
- Customers may voluntarily switch to the adopted end-state successor tariff at any point.

- For SCE and PG&E customers, the interim tariff is expected to yield fully discounted payback periods of 13-15 years and simple payback periods of 8-9 years. For SDG&E customers, the interim tariff is expected to yield fully discounted payback periods of 10 years and simple payback periods of 7.5 years. Details are shown in the tables at the end of this section.

The interim successor tariff should be required for new residential customers until the end-state successor tariff rate is implemented. The end-state successor tariff should be implemented as soon as practicable, and no later than January 1, 2024, once the IOUs have completed any necessary billing system modifications and both the Grid Benefit Charge and any authorized Market Transition Credits are able to be applied.

Modeling results for proposed Interim Successor Tariff
TURN used its cost effectiveness model to assess the impact of the proposed interim successor tariff on residential customers with both stand-alone solar and solar plus paired storage.[22] Sample results for SCE, PG&E and SDG&E customers are shown on the next page. In performing this analysis, TURN made the following assumptions:

- Residential customers take service on an electrification tariff and are assumed to be on a tariff with a baseline prior to adoption.
- Standalone renewable generator is assumed to be solar PV and is sized to serve 100% of first-year load.
- Export compensation is set at a defined percentage reduction to the 2022 <u>Non-CARE</u> net electrification rate, which excludes the following nonbypassable charges -- Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, and Power Charge Indifference Adjustment.
- The E3 SCE, SDG&E, and PG&E load shapes are assumed to be representative of average SCE, SDG&E, and PG&E residential customers prior to adoption.
- For SCE, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 34% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For PG&E, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 44.5% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For SDG&E, there is an 85% reduction to the net electrification rate, which yields exports-weighted compensation of $0.03 per kWh. While this rate is low, it is slightly higher than the export-weighted ACC over the 10-year interim successor tariff term ($0.027 per kWh). In addition, the basic charge, in 2021 dollars, is

---

[22] TURN's entire model was admitted to the evidentiary record (Ex. TRN-5) and was shared with all parties several times during the proceeding.

increased to $1.50 per day for Non-CARE customers and $0.40 per day for CARE customers. With no reduction to the electrification rate, it is possible to achieve a 10-year discounted payback for CARE customers with the change to the basic charge described above.

- Hourly netting is modeled.
- The SCE electrification rate is TOU-D-PRIME, the PG&E electrification rate is EV-2, and the SDG&E electrification rate is EV-TOU-5 (modified with an increase in the basic charge).
- Modeling assumes TURN's capital & operating cost assumptions and financing via a lease. Note that PCT results incorporate only the lease repayments expected to be made through the assumed term of the interim successor tariff.
- All other relevant modeling parameters are the same as those identified in TURN's model and described in testimony.[23]
- The steps to calculate the defined percentage reduction to the 2022 net electrification rate for exports compensation are as follows:

  - Step 1: Calculate imports and exports by TOU period over the interim successor tariff term using the relevant E3 load profile and assuming the standalone renewable generator is sized to serve 100% of first-year load.
  - Step 2: Calculate the standalone renewable generator cost components used in the discounted payback calculation for 2022 and 2023 installations. Costs, including any tax benefits and incentives, are those incurred/received over the interim successor tariff term.
  - Step 3: Calculate the compensation for the E3 load shape assuming the Non-CARE electrification rate for consumption, the 2022 Non-CARE net electrification rate in all years for exports, and the following NBCs assessed on imports: Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, Department of Water Resources Bond-Charge, and Power Charge Indifference Adjustment from full electrification rate.
  - Step 4: Calculate the customer's annual bills prior to and post adoption over the term of the interim successor tariff. Export compensation is the export rate in each TOU period applied to exports in each TOU period. Calculate annual bill savings for 2022 and 2023 installations.
  - Step 5: Calculate discounted payback result.
  - Step 6: For each eligible standalone renewable technology (i.e., solar PV), goal seek on the Non-CARE and CARE customer discounts to the 2022 net electrification rate export compensation to achieve a discounted payback equal to the interim successor tariff term, on average, for 2022 and 2023 installations.

[23] Ex. TRN-1, pages 20-30, 60-63.

TABLE 1
SCE 15-yr Tariff Standalone solar results
34% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.127	$ 0.127	0.40	0.38	1.12	15	8.6	8.8%	$ 548
2022	Non-CARE	34.00%	$ 0.127	$ 0.084	0.40	0.35	1.19	13	8.3	10.2%	$ 580
2023	CARE	2022 export rate (0%)	$ 0.127	$ 0.127	0.40	0.37	1.12	15	8.6	8.9%	$ 574
2023	Non-CARE	2022 export rate (34.0%)	$ 0.127	$ 0.084	0.40	0.35	1.21	13	8.2	10.4%	$ 615

TABLE 2
SCE 15-yr Tariff Paired storage results
assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.192	$ 0.192	0.59	0.58	1.00	18	11.5	6.3%	$ 471
2022	Non-CARE	34.00%	$ 0.192	$ 0.127	0.59	0.45	1.22	12	8.3	10.9%	$ 921
2023	CARE	2022 export rate (0%)	$ 0.192	$ 0.192	0.62	0.60	1.01	17	11.1	6.7%	$ 520
2023	Non-CARE	2022 export rate (34.0%)	$ 0.192	$ 0.127	0.62	0.47	1.24	11	8.1	11.5%	$ 978

TABLE 3
PG&E 15-yr Tariff Standalone solar results
44.5% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.141	$ 0.141	0.31	0.27	1.14	14	8.5	9.2%	$ 701
2022	Non-CARE	44.50%	$ 0.142	$ 0.079	0.31	0.26	1.19	13	8.5	10.1%	$ 696
2023	CARE	2022 export rate (0%)	$ 0.141	$ 0.141	0.30	0.26	1.15	14	8.4	9.4%	$ 702
2023	Non-CARE	2022 export rate (44.5%)	$ 0.142	$ 0.079	0.30	0.25	1.21	13	8.3	10.4%	$ 707

TABLE 4
PG&E 15-yr Tariff Paired storage results
assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.232	$ 0.232	0.42	0.41	1.00	18	12.1	6.1%	$ 553
2022	Non-CARE	44.50%	$ 0.232	$ 0.129	0.43	0.30	1.31	10	7.6	12.7%	$ 1,250
2023	CARE	2022 export rate (0%)	$ 0.232	$ 0.232	0.44	0.41	1.01	17	11.6	6.6%	$ 581
2023	Non-CARE	2022 export rate (44.5%)	$ 0.232	$ 0.129	0.45	0.30	1.34	10	7.3	13.3%	$ 1,290

TABLE 5
SDG&E 10-yr Tariff Standalone solar results
85% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.197	$ 0.197	0.33	0.22	1.32	10	7.4	9.0%	$ 769
2022	Non-CARE	85.00%	$ 0.197	$ 0.030	0.33	0.22	1.33	10	7.4	9.3%	$ 777
2023	CARE	2022 export rate (0%)	$ 0.197	$ 0.197	0.33	0.21	1.35	10	7.1	9.6%	$ 835
2023	Non-CARE	2022 export rate (85%)	$ 0.197	$ 0.030	0.33	0.20	1.38	10	7.1	10.1%	$ 838

TABLE 6
SDG&E 10-yr Tariff Paired storage results
assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.239	$ 0.239	0.52	0.42	1.03	15	11.2	1.4%	$ 613
2022	Non-CARE	85.00%	$ 0.239	$ 0.036	0.52	0.31	1.31	10	7.5	9.1%	$ 1,205
2023	CARE	2022 export rate (0%)	$ 0.239	$ 0.239	0.55	0.44	1.05	15	10.7	2.2%	$ 676
2023	Non-CARE	2022 export rate (85%)	$ 0.239	$ 0.036	0.55	0.31	1.36	9	7.2	10.0%	$ 1,293