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Witnesses:	Paul Chernick and John Wilson

PREPARED DIRECT TESTIMONY OF PAUL L. CHERNICK AND JOHN D. WILSON ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

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EXHIBITS

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, conservation program design, estimation of avoided costs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit RII-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included planning and ratemaking for distributed resources, distributed resource planning, the benefits of load reduction on the distribution and transmission systems, utility planning, marginal costs, and related issues.

I have filed testimony in eleven California PUC proceedings since 2014.

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate

classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit RII-2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two dozen times before utility regulators in California, the Southeast U.S. and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies. I have testified before the California Public Utilities Commission in five proceedings.

II. Introduction

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates (SBUA).

Q: What is the scope of your testimony?

A: We respond to the issues identified in the Scoping Memo (Joint Assigned Commissioner Scoping Memo and Administrative Law Judge Ruling Directing Comment on Proposed Guiding Principles, November 19, 2020), with particular attention to:

- Identifying major characteristics of an appropriate NEM Successor Tariff.
- Describing the NEM Successor Tariff that we have developed, including its effect on distributed renewables development and the economic metrics used in the Energy Division studies.
- Demonstrating the effect of payback period on behind-the-meter renewables and storage.
- Explaining the improvements and corrections we made to the E3 economic models and identifying areas for further improvement.

We also discuss the consistency of our proposal with the principles laid out in the Scoping Memo.

Q: What issues do you address?

A: The Scoping Memo lays out five issues (with numbering starting with number 2) to be addressed in this proceeding.[1] We indicate the location in our testimony where each is addressed in parentheses.

2. 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? (Section IV)
3. 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? (Section V)
4. What program elements or specific features should the Commission include in a successor to the current net energy metering tariff? (Section 0)
5. Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should the timeline be for implementation? (SBUA's proposal in Section VI.E, with discussion of statutory and Commission standards in Section X)
6. 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. (Section IX)

III. Overview of SBUA's Net Energy Metering Successor Proposal

Q: Please provide a brief overview of your NEM Successor proposal.

A: We propose that the NEM successor tariff should be adjusted by reducing the netting period in the current NEM 2.0 tariff to daily TOU periods for residential customers, with net exports valued at full marginal costs as determined by the avoided cost calculator or the utility's most recent rate case. NEM 2.0 rates would remain in effect

[1] *Joint Assigned Commissioner Scoping Memo and Administrative Law Judge Ruling Directing Comment on Proposed Guiding Principles* (November 19, 2020).

for customers in disadvantaged communities and small business customers to ensure continued growth of distributed generation (DG) in those customer groups.

Our proposal has two elements intended to enhance the growth and optimal use of storage. First, the restriction on grid charging of NEM-connected storage systems should be removed, subject to reasonable size restrictions and using a daily TOU netting period. Second, NEM customer groups required to net during daily TOU periods should also be required to utilize a rate with strong marginal cost-based TOU differentiation.

We are also recommending a NEM generation charge to be assessed on the excess of the generation resource (e.g., solar or wind) capacity in excess of the co-sited storage resource.

Finally, we are also proposing a glide path that the Commission could apply to balance the objectives of continued growth with balancing system costs and benefits. Each customer category could progress from annual, to monthly, and then to daily TOU netting periods at a category-specific pace.

Q: Why should the Commission adopt your proposal, as compared to those of other parties?

A: Our proposal's focus on making storage technology an integral part of NEM systems addresses the main issues in this proceeding. As a result of the proposal elements we have described above,

- SBUA's proposal is likely to have a higher total resource cost test score than most other proposals;
- The relative payback periods and participant cost test scores suggest that customers would be incentivized to include storage in their NEM systems; and
- The rate impact of the NEM systems may be justified by the capacity benefit provided by the storage incentivized by our proposal.

We provide a more comprehensive discussion of our proposal in Section VI.E below, including model results using a modified version of the E3/Verdant model provided by the Energy Division.[2]

IV. The Net Energy Metering 2.0 Lookback Study

Q: What information from the Net Energy Metering 2.0 Lookback Study should inform the successor?

A: The Commission should be very cautious in applying any conclusions from the Lookback Study. First, the Lookback Study did not consider relevant differences between residential and commercial customers, especially small businesses. Second, the Lookback Study omitted important benefits and operational considerations of storage systems.

Q: What differences between residential and commercial customers did the Lookback Study overlook?

A: The Lookback Study found lower PCT scores and higher payback periods for commercial participants than for residential participants.[3] This helps explain why only about 2 percent of NEM systems are non-residential.[4] But that is only part of the explanation for low uptake by businesses.

An additional problem is that many small businesses face high barriers to financing their DER systems. The Lookback Study assumes a discount rate of 7.5%

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[2] E3 and Verdant, *Cost-Effectiveness of NEM Successor Rate Proposals Under Rulemaking 20-08*-020, California Public Utilities Commission (June 15, 2021). (Henceforth, "E3/Verdant.")

[3] Verdant, *Net-Energy Metering 2.0 Lookback Study* (January 21, 2021), California Public Utilities Commission Energy Division, p. 90. (Henceforth, "Lookback Study.")

[4] Lookback Study, p. 25. About 12% of California customers are non-residential.

for all purposes except residential PCT scores, based on the IOUs' costs of capital.[5] Small businesses also tend to have a higher discount rate and less access to capital than do utilities or larger businesses.[6] The PCT score calculated with the 7.5% discount rate would need to be significantly greater than 1.0 in encourage widespread small business participation in developing DERs.[7] Realistic PCT scores for small commercial customers would almost certainly be lower than the Lookback Study estimated, providing an additional explanation for the low adoption rate of NEM systems by non-residential customers.

The Lookback Study estimates payback periods for commercial customers between 10.7 and 15.8 years.[8] As shown in Section VI.B, these paybacks are long enough to discourage high saturation of distributed resources, especially for small commercial customers. Payback periods of this length are likely to be cost-prohibitive for small businesses in particular.

Similarly, the Lookback Study found that nonresidential NEM participants tended to have much smaller percentage changes in their bill payments than residential NEM participants.[9] This is further indication that small businesses will

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[5] The Lookback Study used an 8% discount rate for residential customers in the PCT. Lookback Study, p. 124.

[6] National Association of Certified Valuators and Analysts (NACVA), *Commonly Used Methods of Valuation: Fundamentals, Techniques & Theory* (2012), Ch. 5, p. 30.

[7] It is not clear that many small businesses (or households, for that matter) think in terms of the lifetime present values of benefits and costs. Thus, payback is a more realistic metric for attractiveness to most small customers. Large businesses and public agencies may use discounted cashflow models.

[8] Lookback Study, p. 85.

[9] Lookback Study, Figures 5-8 and 5-9, pp. 96-97.

require a favorable regulatory environment if they are to participate in the development of DERs.

Q: What important benefits and operational considerations of storage systems were omitted from the Lookback Study?

A: There are at least two such omissions: the contribution of solar-plus-storage systems to resilience and reliability for the host customer, other customers on the local distribution and the system as a whole; and the capability of storage to shift load and supply to meet system needs in response to pricing signals.

Q: Please explain how Verdant failed to give solar-plus-storage systems credit for their contribution to the reliability and resiliency value they provide to the host or the delivery system.

A: First, Verdant acknowledges that residential customers experience reliability benefits from energy storage systems funded through the Self-Generation Incentive Program (SGIP).[10] The Staff Concept Paper recognized that resiliency is a real benefit that is relevant to the cost-benefit tests; reliability would be similarly enhanced by behind-the-meter DER and especially storage.

Verdant's excuse for excluding resiliency and reliability from the TRC is that Verdant believes that there is considerable uncertainty associated with the value of lost load.[11] While the value of lost load is uncertain, so are the future marginal costs of generation energy and capacity, the costs of future marginal T&D investments, the societal cost of carbon, and nearly all the other inputs into the benefit computations. As we discuss below, it is technically feasible to estimate the value of lost load. The

[10] Lookback Study, p, 67.

[11] Lookback Study, p. 67.

Lookback Study found that solar+storage systems tended have lower TRC test scores than solar-only systems, partially driven by Verdant's decision to ignore reliability and resiliency benefits.[12]

Second, Verdant also errs in assuming that that reliability is purely a private benefit. Reliability and resiliency are neither exclusively private benefits nor benefits that only the utility can provide. As discussed in an Energy Division staff paper on microgrids and resiliency, when storage is used for resiliency it has the ability to mitigate the impact of a large, disruptive event on the utility system by:[13]

- Reducing the magnitude of the disruption, such as by reducing the load that a looped feeder needs to pick up after a fault and allowing more customers to be served,
- Extending the duration of resistance, by more immediately responding to the disruption,
- Reducing the duration of disruption, and/or
- Reducing the duration of recovery, since less load needs to be restored.

The lower net load may also prevent some events entirely, by preventing overloads or low-voltage conditions following a contingency.

It is also possible to deploy storage resources in a manner that the utility can rely on them for dispatch to address reliability problems, both system-wide and locally.[14] For many small businesses, in particular, resiliency is a community benefit, since the ability of fuel stations, food and convenience stores, and other retailers to

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[12] Lookback Study, p. 87.

[13] CPUC Energy Division, *Microgrids and Resiliency Staff Concept Paper* (July 22, 2020), p. 14 (Filed as Attachment 2 in *ALJ Ruling Requesting Comment on Track 2 Microgrid and Resiliency Staff Proposal* (July 23, 2020), R.19-09-009.

[14] By choosing not to model exports to the grid from energy storage systems, Verdant effectively sets the system benefits of these systems to zero as a modeling constraint. Lookback Study, p. 66.

continue functioning can mitigate the effects of a power outage on surrounding customers.[15] Those benefits should be reflected in the relevant tests.

The Commission has made funding decisions based on its recognition that storage systems provide resiliency benefits, such as in D.19-09-027, and should consider resiliency and reliability in the cost-benefit evaluation of NEM successor rates. The Commission has viewed and should continue to treat reliability and resiliency as grid services that customers can be incentivized to partner in providing.

Even if resiliency and reliability *were* entirely private benefits, the California Standard Practice Manual prescribes that the TRC test should be "the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests."[16] Once resiliency and reliability are recognized as benefits, even to the participant, they are to be included in the TRC.

Q: How large are the resilience and reliability benefits of NEM-paired storage?

A: They can be quite large. To estimate the value of resilience to the host customer, we started with the values of lost load (VOLL) underlying the Lawrence Berkeley National Lab (LBNL) presentation to the Resiliency & Microgrids Working Group Value of Resiliency meeting on May 12, 2021 (R.19-09-009).[17] Those values are shown in Table 1.

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[15] The disruption of a power outage is greatly reduced if consumers can keep vehicles operating, charge their phones, and buy food, cooking fuels (propane, charcoal), ice (in the summer) and so on.

[16] *California Standard Practice Manual* (October 2001), p. 18.

[17] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, LBNL-6941E, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* (January 2015). emp.lbl.gov/publications/updated-value-service-reliability. We added 11% inflation from the 2013 dollars in the report to 2020 dollars.

Table 1: Summary of LBNL Estates of VOLL

Class	Momentary	Hours			
		0.5	1	4	8
Residential	$4.33	$5.00	$5.66	$10.55	$19.09
Small C&I	$457	$577	$718	$2,087	$5,206
Medium and Large C&I	$14,377	$16,918	$19,762	$43,798	$93,332

LBNL defines small commercial and industrial customers as those with annual usage under 50,000 kWh, which would generally have peak loads well under 20 kW and be on the smallest non-residential tariff (PG&E B-1, SCE TOU-GS-1, and SDG&E TOU-A). Larger small business customers would presumably have VOLL values per event between those of small C&I and medium-to-large C&I in Table 1.

From the 2019 Annual Electric Reliability Reports filed by the IOUs, we extracted data on average annual interruption hours (SAIDI), annual non-momentary interruptions (SAIFI), and annual momentary interruptions (MAIFI, for outages of less than five minutes duration) over the last ten years. We included all outages (CAISO supply, transmission, distribution, major events, and planned events). For each utility, we selected a frequency of half-hour, one-hour, four-hour and eight-hour events consistent with the average SAIDI and SAIFI, and multiplied those frequencies by the VOLL per outage from Table 1.[18] The results are shown in Table 2.

[18] We used the reported MAIFI rate for momentary outages.

Table 2: Outage Statistics and Implied Annual Resilience Value, 2010–2019

IOU	SAIDI	SAIFI	MAIFI	Annual VOLL per Customer		
				Residential	Small C&I	Larger C&I
PG&E	6.01	1.43	1.76	$19.83	$4,236	$100,238
SCE	2.33	1.00	1.48	$12.34	$2,061	$53,831
SDG&E	2.29	0.69	0.33	$6.83	$1,471	$35,446

The residential resilience benefit is quite small, because the LBNL results indicate that average residential customers did not express much willingness to pay for higher reliability. Those surveys were taken before the recent PSPS and weather-related outages; now that customers have experienced the effects of outages, their willingness to pay for reliability may be higher.

The small-business VOLL, on the other hand, is substantial, with a TRC present value of $13,500 to $35,000 over 20 years at 7.5% discount rates.

Q: Would behind-the-meter storage eliminate all lost load due to grid outages?

A: Probably not. Depending on the size of storage, state of charge, solar production and host customer demand during the outage, the customer's ability to reduce non-essential load, and the length of the outage, storage may not be able to carry every customer through every outage.

Q: Should the resilience values you computed be discounted to reflect the occasional failure of storage to carry the host's total load for the length of the outage?

A: No. In addition to the resilience benefits to the host from avoiding outages of more than five minutes, storage would provide additional reliability benefits to customers sharing equipment with the host, such as the following;

- other customers on the same line transformer when the solar and storage reduces loading on the transformer and avoids overloading,

- customers on the same feeder or substation when overloads and failure are avoided, and
- customers on a looped feeder that would receive post-contingency back-up supply from the customer's feeder, due to load reductions on the customer's feeder freeing up capacity.

Those additional benefits would directionally offset any outage costs that would still be borne by the host customer.

Q: How did Verdant's modeling understate the flexibility of behind-the-meter storage?

A: Verdant's evaluation constrained battery storage "to discharge only to achieve zero net load," and thus prohibited discharge from the battery to the grid. While this reflects NEM 2.0 policy, the Commission should not include this constraint in the successor NEM tariffs. Any modeling of the successor NEM tariffs that considers discharge from the battery to the grid will require removal of this constraint and thus cannot directly use the findings in the Lookback Study. Battery storage systems that are allowed to export to the grid, with appropriate time-varying prices, will tend to have higher TRC, PCT and RIM test scores because price-driven arbitrage enables customers to reduce their bills and reduce system costs.

Q: How should the Commission apply those observations?

A: The Commission confirmed in D.21-02-007 that cost-effectiveness should be conducted in the manner directed by D.19-05-019, which concluded that the TRC is the primary test for evaluating the cost-effectiveness of distributed energy resources (DERs). The Commission should require that the TRC include estimates of the public and private value of lost load avoided by distributed energy resources (DER).

The Commission should also include reliability and resiliency benefits in non-participant and participant analyses. The benefits in the RIM test are conventionally limited to the savings from avoided system costs. The resiliency and reliability

created by behind-the-meter storage systems provide real system benefits that would otherwise require additional system investments. Those are real benefits to all customers, consistent with state policy, and should be included in any test purporting to represent the interests of customers without DER.

Similarly, the private resiliency benefits associated with storage systems should be recognized in participant analyses. If the Commission does not adopt estimates of the value of lost load avoided by DERs, then it could determine proxy for resilience, based on the cost of non-NEM backup, perhaps applied as a percentage of DER costs assumed to be offset by resiliency benefits.

Q: What findings and recommendations should the Commission adopt with respect to the analysis of NEM systems?

A: The Commission should adopt the following findings.

1. Small businesses are recognized as having higher discount rates than utility systems or large businesses.
2. Because small businesses have higher discount rates and less access to capital than most other types of customers, a NEM Successor Tariff should include policies that allow for shorter payback periods and higher PCT scores than for other customer groups, comparable to those for residential CARE customers.
3. Battery storage systems that are allowed to export to the grid, with appropriate time-varying prices, will tend to have higher TRC, PCT and RIM test scores because price-driven arbitrage enables customers to reduce both their bills and system costs.
4. Resiliency is a real public and private benefit that is relevant to the cost-benefit tests.
5. The omission of resiliency from cost-benefit tests results in TRC, PCT, and RIM scores that underestimate the benefits of NEM systems with storage.

The Commission should adopt the following recommendations.

1. The Commission accepts that a cost-benefit test of a NEM system with storage is likely to underestimate the benefits (a) if price-driven arbitrage is not considered in the storage profile and (b) until an appropriate estimate of resiliency is included in the calculation, and thus it is appropriate to approve NEM tariffs with TRC scores less than 1.0 where the Commission determines that resiliency could increase the score above 1.0.

2. The Commission should open a Phase 2 of this proceeding to determine appropriate estimates of resiliency for purposes of evaluating the benefits of storage and applying those benefits in ratesetting.

V. Perspective for Reviewing NEM Successor Tariff Proposals

Q: What perspective should the Commission use to analyze the proposals for NEM successor tariffs?

A: SBUA recommends that the Commission evaluate the proposals in three steps.

First, the Commission should select a NEM successor tariff that is likely to lead to the majority of NEM systems having a TRC score of 1.0 or greater, as stated in PUC §2827.1, which states that the tariff should "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," and as the Commission has adopted the TRC score as the primary test for evaluating the cost-effectiveness of DERs. Similarly, guiding principle (g) directs that the "tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system."

However, just as with energy efficiency programs, some installations may have TRC scores above 1.0, and others may be lower. This may be due to installation timing, site-specific conditions, customer preferences, or the Commission's equity goals. The goal is that the overall NEM program should be cost-effective, including all costs and benefits.

Second, in determining the rate at which different customer groups are likely to install NEM systems in the future, the Commission should rely on the payback period and to a lesser extent the PCT. Few residential or small business customers will undertake, or even understand, a discounted cash-flow analysis. As stated in PUC §2827.1, the tariff should ensure "customer-sited renewable distributed generation

continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

Within customer groups, the Commission should consider the relative payback scores to determine whether customers are more likely to install NEM generation-only or paired-storage systems. Between customer groups, the Commission should consider payback in estimating the DER adoption rates for each customer group. For example, as discussed above, small businesses will require a shorter payback period and higher PCT score than other customer groups in order to participate.

This determination should inform both (a) the relative weighting of different customer/technology combinations for purposes of estimating whether the likely NEM program TRC score will be greater than 1.0 and (b) the appropriate policies for each customer group (e.g., residential non-CARE, residential CARE, small business).

Third, the Commission should evaluate impacts on non-participants using the first-year cost shift and RIM test results. This step in the process should be considered a balancing test, with an effort to minimize total impacts on non-participants. While impacts on non-participants are not explicitly considered in the guiding principles adopted in D.21-02-007 or in PUC §2827.1, the guiding principles do state, "A successor to the net energy metering tariff should ensure equity among customers." While our discussion of the payback and PCT scores provides for a degree of equity respecting adoption rates between different customer groups, this third step should add consideration of equity among customers who do not choose to or are not able to install NEM systems.[19]

[19] Equity can also be increased by facilitating access to community DER for customers who do not have the option of behind-the-meter solar-plus-storage.

Indeed, as advocates for small business interests, we find those customers generally on the losing end of both perspectives. They have not found the NEM tariff to be attractive and as non-participants they have experienced a degree of rate impacts from the program. Thus, we are fully supportive of the need for updating the NEM tariff.

To ensure that non-participants are better off under the NEM successor tariff, the Commission should use the first-year cost shift and RIM test results as balancing tests, with a goal of minimizing the cost shift and maximizing RIM test results, provided that the net TRC benefits are not reduced and the payback tests indicate that customer-sited renewable distributed generation will continue to grow sustainably, with equitable distribution across customer groups.

Q: How should the Commission endure that proposals comply with the guiding principles?

A: The three steps we outlined above principally address guiding principles (a), (b), and (g) where we anticipate fundamental differences among the parties' proposals. The remaining principles reflect areas in which the proposals and eventual tariffs should be examined in more detail and revised as necessary.

c) A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services;

d) 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;

e) 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, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18;

f) 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;

h) A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.

After identifying one or more leading proposals from the parties, the Commission should identify whether those proposals have any fatal flaws with respect to the five principles listed above, as well as further aspects of PUC §2827.1 not already considered, including:

- Any further program considerations necessary to "include specific alternatives designed for growth among residential customers in disadvantaged communities;"
- "Terms of service and billing rules;"
- Allowing projects greater than one megawatt built to the size of onsite load; and
- Consideration of appropriate transition periods.

In many respects, such as the transparency of the terms of service and billing rules, these issues will be better addressed in a Phase 2 proceeding in which the IOUs are directed to propose specific language following the Commission's adoption of a NEM successor tariff proposal.

Q: What findings should the Commission adopt with respect to reviewing NEM successor tariff proposals?

A: The Commission should adopt the following findings.

1. NEM successor tariffs should be evaluated by:
    a. Selecting a NEM successor tariff that is likely to lead to the majority of NEM systems having a TRC score of 1.0 or greater, recognizing that some systems and customer groups may have scores below 1.0, but achieving an overall program average of 1.0 or greater.
    b. To determine the rate at which different customer groups are likely to install NEM systems, the payback period should be the primary indicator, with lessor consideration of the PCT score. Payback periods should be considered both as an absolute value, and as a relative value, comparing NEM generation-only systems to NEM paired-storage systems.

c. To evaluate the impacts on non-participants, the first-year cost shift and RIM test results should be used as a balancing test, with an effort to minimize total impacts on non-participants.

d. After identifying one or more leading NEM successor tariff proposals, the Commission should identify whether those proposals have any fatal flaws with respect to guiding principles (c), (d), (e), (f), and (h), as well as further aspects of PUC §2827.1 not already considered.

2. Some of the guiding principles and statutory requirements are better addressed in a second phase of this proceeding because they relate to technical details of the tariff that should be resolved after selecting the NEM successor tariff design.

VI. Analyzing NEM Successor Tariff Proposals

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

A: The Commission should select a proposal that includes the following elements.

- Favors NEM systems that include storage
- Allows NEM storage to charge from the grid
- Maintains an emphasis on volumetric rates
- Provides an adequate payback period, which may vary by customer group

A. Favor NEM systems that include storage

Q: Why should the Commission adopt a tariff that favors NEM systems with storage?

A: In the Integrated Resource Planning process and in Phase 2 General Rate Cases, the Commission has identified storage as the principal resource that will provide future capacity. For example, the base case portfolio adopted by the Commission in D.21-02-008 for the 2021-2022 Transmission Planning Process (TPP) includes 9 GW of

new battery storage, 16 GW of new in-state renewables, and geothermal and pumped storage resources.[20]

A similar perspective is discussed in the NEM Successor Tariff White Paper, which states that BTM solar systems produce maximum output before the hours when the system benefits are highest.[21] Battery storage systems can provide significant additional value by storing generation supplied during lower-value midday hours for use during the higher-value evening hours. With such a shift, storage provides enhanced benefits—particularly generation capacity—compared to the mainly energy and CO_2 reduction benefits of solar power.

Neither the Lookback Study nor the White Paper gave extensive treatment to the effect of NEM tariff restrictions on the benefits provided by storage systems. If utility tariffs are well-aligned with high system cost hours, and if storage systems have high roundtrip (charge cycle) efficiencies, then NEM-paired storage systems are likely to result in lower system emissions and costs.

In spite of the opportunity to lower system emissions and costs, as well as provide customer resiliency, storage is present in fewer than 6% of NEM systems.[22] Storage systems are particularly rare for lower income and non-residential customers. Currently, the incremental costs of energy storage are greater than the additional benefits provided by these systems on the NEM 2.0 tariff. Battery storage system costs are declining rapidly, so designing the NEM successor tariff to optimize storage

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[20] See also the proposed decision on mid-term reliability, R.20-05-003 (May 21, 2021), pp. 39–40.

[21] E3 and Verdant, *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California* (January 28, 2021), California Public Utilities Commission, p. 11. (Henceforth, "White Paper.")

[22] Lookback Study, Figure 3-4, p. 27.

benefits would enable growth in the number of customers—including small businesses—who deploy NEM-paired energy storage systems.

B. Allow NEM storage to charge from the grid

Q: Why should the Commission adopt a tariff that allows NEM storage to charge from the grid?

A: Since 2014, the Commission has required NEM-paired storage systems to be configured and metered to ensure energy cannot be imported from the grid and then stored for potential export. This limitation appears to derive from California Energy Commission regulations related to Renewable Energy Credits (RECs). Currently, the CEC requires that energy storage technologies must be integrated or directly connected to the facility such that "Only generation attributable to the eligible renewable energy resource may be eligible to produce RECs."[23] According to the Lookback Study, REC prices are so unfavorable that customers are unlikely to sell them.[24]

Since the Commission established its policy regarding NEM-paired storage systems, two relevant policy developments have undercut the rationale for that decision.

- The Commission has methodically transitioned residential customers to time-of-use (TOU) rates. In Decision D.17-01-006, the Commission stated that, "TOU rates should encourage customers to configure their [NEM] systems to generate energy at times that better align with the later-shifted peak periods, e.g., via installation of co-located energy storage."

[23] California Energy Commission, *Renewables Portfolio Standard Eligibility*, Commission Guidebook, CEC-300-2016-006-ED9-CMF-REV (January 2017), pp. 40-41.

[24] Verdant, *Net-Energy Metering 2.0 Lookback* Study, Submitted to CPUC Energy Division (January 21, 2021), p. 72. (Hereafter, "Lookback Study.")

- Senate Bill 700 enacted PUC §379.6(a)(1), directing the Commission to "increase deployment of distributed generation and energy storage systems to facilitate the integration of those resources into the electrical grid, improve efficiency and reliability of the distribution and transmission system, and reduce emissions of greenhouse gases, peak demand, and ratepayer costs."

While TOU rates and the NEM 2.0 tariff provide incentives to use NEM-paired storage systems to achieve better alignment with evening peak periods, optimal use of those storage systems to shift grid power from off-peak to on-peak, even for the customer's own use, is not permitted.

Furthermore, the June 9, 2021 proposed decision suspending the standby charge for microgrids in R.19-09-009 offers an insightful analysis of the relationship between the character of capacity self-supplied by customer-generators to the need for back-up capacity provided by the load serving entity. We will explore the relevance of this proposed decision later in our testimony.

There is ample precedent for the Commission to ensure that further growth in NEM systems, particularly solar resources, is paired with storage capacity. Where solar resources result in power flow back through the distribution system, co-locating storage systems with the NEM generation can reduce overloads and line losses. A NEM successor tariff that successfully balances costs and benefits of solar-plus-storage systems would be preferrable to one that merely discourages uneconomic NEM system investments.

Adopting a tariff that allows NEM storage to charge from the grid would make the NEM generation ineligible for RECs. Considering the low value and high administrative hassle of REC transactions, the Commission should abandon them in a NEM successor tariff.

C. Maintain Emphasis on Volumetric Rates

Q: Why should the Commission adopt a tariff that maintains an emphasis on volumetric rates?

A: The Commission's rate design principles emphasize the use of volumetric rates, by being based on marginal cost, to encourage conservation and energy efficiency.[25] Many of the proposals originally advanced in the White Paper and also included in parties' initial proposals shift away from volumetric rates. To the extent that proposals for a NEM successor tariff shift away from volumetric rates, customers would experience reduced marginal electricity energy prices, reducing their incentive to invest in energy efficiency, exercise care in consumption, or shift the timing of energy demands. Maintaining a focus on volumetric rates, as suggested by the Commission's Rate Design Principles, will be more effective at reducing system costs and emissions.

D. Payback and Solar Acceptance

Q: How should the Commission ensure that a NEM successor tariff provides an adequate payback period?

A: For residential customers, the Commission should examine evidence regarding the relationship between payback periods for residential BTM solar installations and the market acceptance rate. For commercial customers, the Commission should consider evidence regarding the differing payback periods for different sized businesses.

Q: What is an adequate payback period for residential customers?

A: Considering that PUC §2827.1 requires that the NEM tariff must ensure "customer-sited renewable distributed generation continues to grow sustainably," a payback

[25] Summarized in OIR, R.12-06-013 (November 26, 2012), Attachment A, p. 1.

period of 7 to 9 years may be reasonable. As discussed below, increasing the payback period to 9 years would reduce solar uptake by about 55%. A payback period much in excess of 9 years risks effectively eliminating the growth of customer-sited renewable distributed generation.

We reached this finding based on our analysis of state level data from several sources. Figure 1 shows the relationship between the estimated years to payback for solar installations and the estimated ratio of residential behind-the-meter solar capacity installed by December 2019 to the potential capacity suitable small roofs.

- For the payback period, we used the average of the payback reported for each continental US state (and DC) by Energy Sage and Solar Nation, two widely-cited web sites that collectively provide estimates for all 49 jurisdictions.[26]
- For the actual installation rate, we used the capacity of residential behind-the-meter solar installations from the December 2020 version of the EIA-861M detailed data file "Estimated Small Scale Solar PV Capacity and Generation- Current Month."[27]
- For the potential installation rate, we used an NREL analysis of rooftop PV technical potential for small buildings (those with a footprint smaller than 5,000 ft^2, and hence mostly residential) by state.[28] The study found about 26% of total rooftop area may be suitable for PV deployment.

The trend line suggests that increasing the payback period from about five years to nine years would reduce solar uptake by about 55% and increasing payback to 12 years would reduce solar uptake about 85%. If the trend-line correctly predicts

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[26] The values were downloaded in early 2021 from www.energysage.com/solar-panels/xx/, where xx is the state postal code, and www.solar-nation.org/[state], where [state] is the state's full name, hyphenated if 2 words.

[27] https://www.eia.gov/electricity/data/eia861m/

[28] Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment; Pieter Gagnon, Robert Margolis, Jennifer Melius, Caleb Phillips, and Ryan Elmore, National Renewable Energy Laboratory, Technical Report NREL/TP-6A20-65298, January 2016, Table 3 https://www.nrel.gov/docs/fy16osti/65298.pdf.

customer response, increasing payback periods to the 15 years would reduce solar uptake about 95%, or 1/20th of the acceptance with a five-year payback. For example, the paybacks computed by E3 for the Joint IOUs and TURN proposals (about 17 and 21 years, respectively, for a 2023 non-CARE residential solar system[29]) would reduce uptake by a factor of 34 and 63, respectively, compared to a six-year payback.

[29] E3/Verdant, Table 16, p. 53.

Figure 1: Relationship of Payback to Acceptance

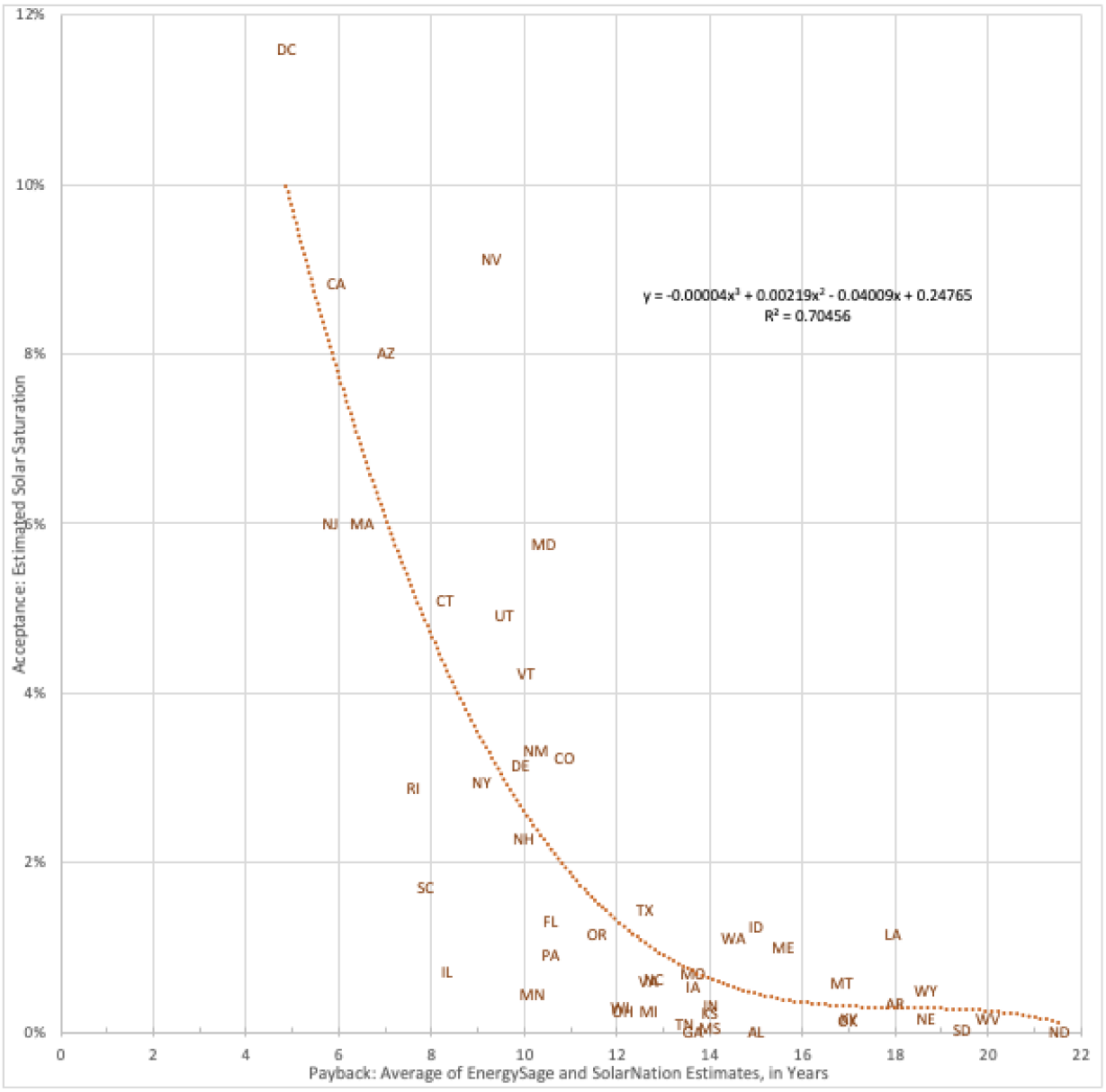


Table 3 summarizes the implied effect of payback on solar uptake, expressed as uptake normalized to a 5-year payback, percentage reduction in uptake, and factor reduction. We included factor reduction because percentages near 100% may be difficult to distinguish. By factor reduction, we mean that a nine-year payback reduces uptake by more than a factor of almost three and 21-year payback reduces uptake by a factor of 50.

Table 3: Effect of Selected Increases in Solar Payback

Payback Years	Relative Uptake	Percentage Reduction	Factor Reduction
5	1.00	0%	1.0
6	0.80	20%	1.3
7	0.63	37%	1.6
9	0.36	64%	2.8
11	0.19	81%	5.2
12	0.13	87%	7.4
15	0.05	95%	22.2
17	0.03	97%	33.6
19	0.03	97%	37.5
21	0.02	98%	62.6

Q: How could your estimated relationship of payback period to market saturation be improved?

A: With additional data sources or granularity, our analysis could be improved.

With respect to the technical potential for residential solar, there are several issues with the data. NREL's assessment of rooftops does not include such factors as the age of the roofing material, the structural integrity of the roof, or the influence of homeowners' associations and historical districts on installation of visible solar panels. NREL's small building category, those with a footprint smaller than 5,000 ft^2, includes some small commercial buildings, in addition to nearly all single-family homes. In contrast, the other data we used are for residential systems.

Any point estimate of a statewide average payback is inherently uncertain. The surveys from Energy Sage and Solar Nation payback estimates differ, although they

are highly correlated.[30] Any such survey is complicated by the large number of utilities and rate designs in a state, and may also be affected by the limitations on the size of customers considered in the analysis. For example, an estimate of statewide payback may be derived from the costs reported by a large customers who use a particular web site in their search for information or contractors, or for a few typical installations.

Finally, the number of solar installations as of December 2020 reflects the paybacks faced by customers over the preceding several years. Two states with similar nine-year paybacks in early 2021 may have very different histories of paybacks over the preceding decade, with one having provided five-year paybacks in the 2010s and the other offering twenty-year paybacks. Solar installations in the first state could have taken off in the early part of the decade. By 2021, both states would have the same nine-year paybacks, but the 2021 saturation data would show the large number of earlier installations in the first state, and perhaps the effect of an established installation network, while the second state's data would show none of those effects.

A simple payback analysis also fails to consider non-financial barriers to installing solar (e.g., the difficulty of finding installers and neighbors who can recommend installers, the delay imposed by the permitting authority and the local utility). Two states with similar paybacks may have different installation rates, due to the effects of state and utility non-price policies.

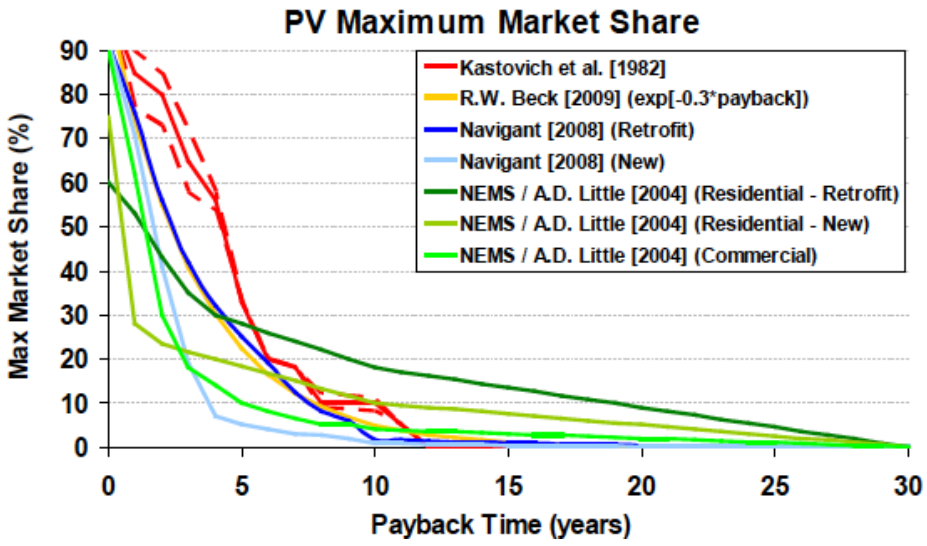
[30] Solar Nation reports paybacks for some states (usually with low solar saturation and high paybacks) for which Energy Sage does not report data.

Improved data and granularity of analysis could lead to an improved estimate of the payback/acceptance curve, but we believe this evidence is the most useful data available at this time.

Q: Have other researchers estimated the effect of payback on behind-the-meter solar acceptance?

A: Yes, several studies have used customer-reported willingness to pay, or similar measures to estimate maximum saturation as a function of payback. While the details vary, the general shapes of the required payback curves are consistent with our results. A 2010 review by NREL compared various estimates of the maximum market saturation (which would require many more years than the historical data reveal), as reproduced in Figure 2.[31]

Figure 2: Relationship between PV payback times and maximum market share[32]

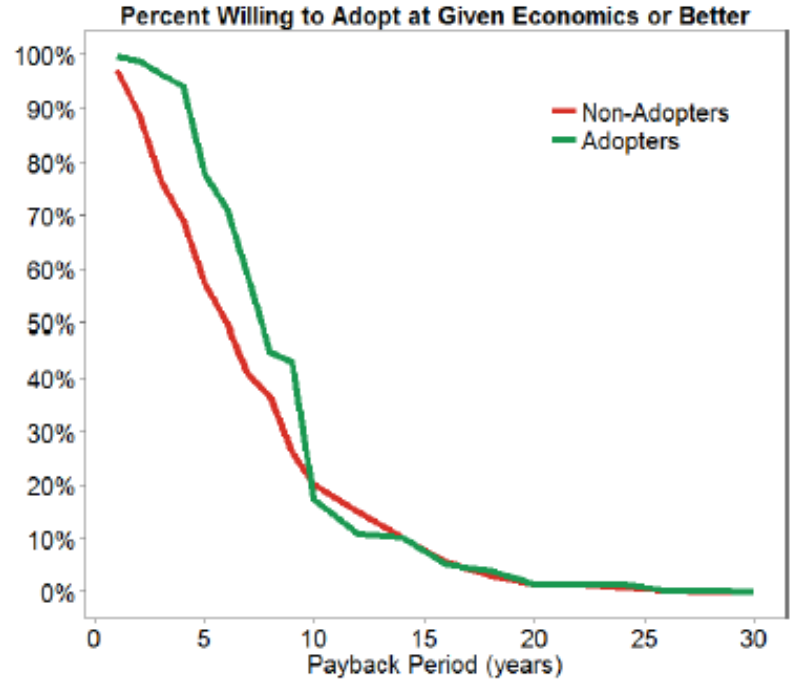


[31] The 1982 Kastovich study would have been quite speculative, considering the cost of solar in 1982.

[32] Drury, E., Denholm, P., and Margolis, R, *Modeling the U.S. Rooftop Photovoltaics Market* (September 2010), Figure 5. https://www.osti.gov/servlets/purl/991053.

Another NREL report differentiated between residential customers who had adopted rooftop solar and those that had not yet done so. Figure 3 reproduces those results.

Figure 3: Customer willingness-to-adopt for given payback period or better[33]



E. Summary of Priorities for Analyzing Proposals

Q: What findings should the Commission adopt with respect to the analyzing NEM successor tariff proposals?

A: The Commission should adopt the following findings.

1. A NEM successor tariff that favors NEM paired-storage systems should be preferred because storage is the principle resource that will provide future capacity. Currently, fewer than 6 percent of NEM systems include storage, and

[33] Ben Sigrin, Easan Drury, *Diffusion into new markets: Economic returns required by households to adopt rooftop photovoltaics* (January 2014), National Renewable Energy Laboratory, Figure 3. www.researchgate.net/publication/282888559_Diffusion_into_new_markets_Economic_returns_required_by_households_to_adopt_rooftop_photovoltaics

the NEM successor tariff should drive customer adoption of storage to a much higher share of total NEM installations.

2. A NEM successor tariff should allow charging of paired-storage systems from the grid. Since the adoption of the requirement that NEM paired-storage systems must be configured to ensure energy cannot be imported from the grid and then stored for potential export, the Commission has transitioned residential customers to TOU rates and been directed by PUC §379.6(a)(1) to increase deployment of storage systems.
3. A NEM successor tariff should maintain an emphasis on volumetric rates. The Commission's rate design principles emphasize the use of volumetric rates, by being based on marginal cost, to encourage conservation and energy efficiency. Maintaining a focus on volumetric rates will be more effective at reducing system costs and emissions.
4. A NEM successor tariff should provide an adequate payback period.
    a. A payback period of 7 to 9 years generally provides a reasonable balance for ensuring that customer-sited renewable generation continues to grow sustainably. A payback period much in excess of 9 years risks effectively eliminating that growth.
    b. A shorter payback period is appropriate for customer groups who have not participated in the NEM market at high levels.

VII. SBUA NEM Successor Tariff Proposal

Q: Please summarize SBUA's proposal.

A: We propose that the NEM successor tariff should be adjusted by reducing the netting period in the current NEM 2.0 tariff to daily TOU periods for residential customers, with net exports valued at full marginal costs as determined by the avoided cost calculator or the utility's most recent rate case. NEM 2.0 netting practices would remain in effect for customers in disadvantaged communities and small business customers to ensure continued growth of distributed generation (DG) in those customer groups.

Our proposal has two elements intended to enhance the growth and optimal use of storage. First, the restriction on grid charging of NEM-paired storage systems would be removed, subject to reasonable size restrictions and using a daily TOU

netting period. Second, NEM customer groups required to net based on daily TOU periods should also be required to utilize a rate with strong marginal cost-based TOU differentiation.

We are also recommending a NEM generation charge to be assessed on the generation resource (e.g., solar or wind) capacity in excess of the co-sited storage resource. For example, a customer with a 4 kW solar system and a 4 kW 2-hour battery system would have no generation charge, but a customer with a 4 kW solar system and a 1 kW 2-hour battery system would have a 3 kW NEM generation charge. Similarly, a customer with a 2 kW 4-hour battery system would have no NEM generation charge.

Finally, we are also proposing a glide path that the Commission could apply to balance the objectives of continued growth with balancing system costs and benefits. As shown in Table 4, each customer category could progress from annual, to monthly, and then to daily TOU netting periods at a category-specific pace.

Table 4: Proposed Initial and Final Netting Periods, by Customer Category

Customer Category	Initial Netting Period		Final Netting Period
	No Grid Storage	Storage	
Residential	Monthly	Daily	Daily
Disadvantaged Community	Annual	Daily	Daily
Small Business < 500 kW	Annual	Daily	Daily
Critical Facilities	Annual	Daily	Daily
All Other Non-Residential	Monthly	Daily	Daily
All Systems > 1 MW	Monthly	Daily	Daily

Q: Why is SBUA's proposal so similar to the NEM 2.0 design?

A: Consistent with the Commissions' rate design principles, we believe the NEM successor tariff should be as stable as possible.[34] In particular, SBUA found it possible to retain the concept of "net energy" rather than "net billing," over a much shorter period of time—daily TOU periods rather than the entire year.

In the NEM 2.0 decision (D.16-01-044), the Commission fully addressed most of the statutory requirements of Section 2827.1, but left questions for further consideration, as follows.

- "… the benefits and costs of the NEM successor tariff to all customers and the electric system are not well characterized at this time." (COL 22)
- "In order to ensure that the NEM successor tariff is consistent with Commission policy on distributed energy resources, makes use of relevant information about locational benefits and optimal DG resources, and is appropriately aligned with changes to retail rates for residential customers, the successor tariff adopted in this decision should be reviewed in 2019." (COL 25)

The various Energy Division studies completed for this proceeding have informed parties regarding the benefits and costs of the existing NEM tariff as well as providing a common basis on which parties may consider the benefits and costs of various NEM successor tariff proposals. These tools also provide a means for consideration of changes to retail rates for residential (and other) customers.

SBUA's proposal is primarily focused on the unresolved issues of benefits and costs and of optimal DG resources, and does not revisit issues resolved in NEM 2.0, except as required by the ALJ's instructions for successor proposals (January 28,

[34] See Commission Rate Design Principle 6, summarized in OIR, R.12-06-013 (November 26, 2012), Attachment A, p. 1.

2021). The only issue left unresolved from the NEM 2.0 decision is the question of locational benefits.

We note that our proposal does not change the following elements of the NEM 2.0 Tariff.

- Interconnection fees should continue to be assessed on the same basis and waived for certain low-income and disadvantaged customers.
- Generation from NEM systems should not be subject to any departing load charges, although nonbypassable charges should continue to be applied to all grid-supplied power irrespective of exported power used for netting credit.
- Systems 1 MW or larger should continue to be treated identically to smaller systems and interconnection costs should continue to be project-specific, except that a monthly netting period should be used for non-storage systems, irrespective of customer category.
- Other than application of monthly netting periods, special rules and methods for net energy metering aggregation and virtual net energy metering should be maintained.

A. SBUA's Daily TOU Netting Proposal

Q: Please explain how the NEM 2.0 tariff compensates exported power.

A: The manner in which the NEM 2.0 tariff compensates exported power can be described as a three-step netting process.[35] First, all energy supplied from the grid to the customer is billed based on the applicable tariff, including nonbypassable charges.[36]

Second, net electricity use or export is totaled by TOU period on a monthly basis. For each TOU period with net usage, the customer bill reflects a charge for

[35] The description is for rates without a demand charge.

[36] Nonbypassable charges were determined to be the Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Wildfire Fund (formerly, Department of Water Resources Bond) charges in D.16-01-044.

energy use at the applicable retail rate (recalling that the nonbypassable charges are covered in the first step). For each TOU period with net exports to the grid, the customer bill reflects a credit at the applicable retail rate (nonbypassable charges are not included in the export credit).

Thus, the monthly bill reflects payment for all energy imported from the grid at the applicable retail rate, and credits for net exports to the grid. If those the charges and credits (by TOU period) total to a credit, that credit is carried forward to the next month. (The customer's monthly bill also includes a monthly minimum charge for customer costs.)

Third, there is an annual true-up, if the customer produced power in excess of its on-site load over the year and was thus a net exporter to the system. In that case, the customer may be paid "net surplus compensation" at the avoided cost of energy averaged over all 8,760 hours of the year. (This value is roughly 3 cents per kWh.) The true-up, based on net energy export, replaces the dollar-based cumulative year-end credit.

Q: Please explain how SBUA's proposed daily TOU netting compensates exported power.

A: Our proposal tracks the same three-step process, but with some significant updates.

The first step is unchanged. All energy supplied from the grid to the customer is billed based on the applicable tariff, including nonbypassable charges.

In the second step, instead of net electricity use or export being totaled by TOU period on a monthly basis, we are proposing totaling on a daily basis. And further, for each TOU period with *daily* net exports to the grid, the customer bill would reflect a credit at the applicable full avoided-cost rate for the TOU period, rather than the

applicable retail rate. The avoided cost rate would include all components.[37] When a TOU period continues past midnight and thus extends across two days, the credit would be determined at the end of the TOU period (not at midnight).

For customer groups who are not yet on a daily TOU netting period, the same approach would occur but over the applicable (monthly or annual) period. For these monthly or annual netting customer groups, net exports to the grid would be reflected as a credit at the applicable full avoided cost rate for the TOU period, rather than the applicable retail rate used in the current NEM 2.0 tariff.

Treatment of nonbypassable charges would not be affected. An example of daily netting is provided in Table 5.

[37] We also support eventual mandatory transition of some or potentially all NEM customers to day-ahead hourly real time pricing rates (DAHRTP), such as those being developed for PG&E. However, mandatory transition should only be approved for a customer class after the DAHRTP rates are proven to be transparent and understandable to customers through voluntary opt-in. The concept of daily TOU netting would have to be revisited for such rates.

Table 5: Example of Daily Netting Calculation

	Hour	Customer Load		NEM Generation		Customer Net Load	
		Hourly	Daily TOU Period	Hourly	Daily TOU Period	Hourly	Daily TOU Period
Off-Peak	6	1.45		0.00		1.45	
	7	1.65		0.00		1.65	
	8	1.78		0.17		1.61	
	9	1.83		0.63		1.20	
	10	1.87		0.58		1.29	
	11	1.88		0.36		1.52	
	12	1.88		2.09		- 0.21	
	13	1.83		1.52		0.31	
	14	1.79		1.03		0.77	
	15	1.80	**17.76**	2.22	**8.59**	- 0.42	**9.17**
On-Peak	16	1.96		0.22		1.74	
	17	2.34		0.00		2.34	
	18	2.49		0.00		2.49	
	19	2.39		0.00		2.39	
	20	2.31	**11.49**	0.00	**0.22**	2.31	**11.27**

Q: Why is SBUA's proposed daily TOU netting proposal reasonable?

A: Netting over a multi-hour TOU period (rather than an hour or a 15-minute billing increment) would present customers with reasonable pricing signals while maintaining a focus on volumetric pricing. Short-term fluctuations in individual customers' net load, as refrigerators and air conditioners switch on and off, have little effect on generation loss-of-load-expectation (LOLE) or cost, or distribution overloads, which are significant over multiple hours. A very short-term netting period would encourage customers to waste their effort and money on enabling technologies (storage and automatic controls) to smooth out inconsequential variation.

In contrast, using daily TOU period netting could be more compatible with management of load and storage. The use of daily TOU period netting should

generally reflect system economics more accurately than an hourly or 15-minute billing increment.[38]

Credits would continue to be carried forward with the potential for excess power generation to be credited using the current "net surplus compensation" method during the annual true-up.[39] The NSC rate would continue to be used for the annual true-up, where it is not practical to determine the hours in which the surplus solar exports occurred.

SBUA also considered an alternative approach to maintaining the emphasis on volumetric rates, which is likely to be proposed by other parties, of simply reducing the export rate from the current full retail export rate. Under such an approach, a NEM customer might be compensated for exports using a reduced rate (*e.g.*, 90% or 60% of full retail rates) which would be applied to exports during each billing increment (typically, 15 minutes). This approach may have advantages for solar-only systems. For NEM-paired storage systems, however, the reduced export rate would result in a proportionately lower roundtrip rate differential and would not provide an opportunity to net within the TOU period. The smaller differential between rates for charging and discharging and the lack of opportunity to net within the TOU period would provide a smaller economic incentive to install NEM-paired storage systems than daily TOU netting using the full import rate.

[38] For larger customers (> 1 MW), a shorter billing increment may be justified. We have not analyzed this question.

[39] We would also support the use of utility-specific marginal costs as determined in the most recent General Rate Case in lieu of some or potentially all components of avoided costs.

Q: What is the benefits of allowing storage systems to charge from the grid?

A: One of the most significant differences between SBUA's approach and those of other parties is eliminating the requirement that NEM-paired storage be charged only from renewable generation. Since the Commission adopted that requirement in 2014,[40] California law and Commission policy have changed. The use of TOU or critical peak pricing (CPP) rates now creates an opportunity to better integrate energy storage systems into the electrical grid using NEM tariffs.

For this reason, our proposal requires NEM customer groups that are required to net over daily TOU periods to utilize a generally-available rate with strong marginal-cost-based TOU differentiation. In the residential model analysis, E3/Verdant provided representative EV rates which are intended to promote electrification. We used these rates for our analysis of solar+storage systems. However, in the commercial model analysis, E3/Verdant did not include rates with strong marginal cost-based TOU differentiation.[41]

Our proposal also allows NEM-paired storage systems to charge from the grid without restriction, with a daily TOU netting period appropriately limiting the benefit of time-shifting grid energy. Shifting California's NEM program to a greater focus on storage anticipates declining costs of battery storage systems, as well as emphasizing NEM deployments in underserved markets. Optimizing the use of NEM-paired storage is consistent with the Commission's rate design and NEM

[40] Decision D.14-05-033, Conclusion of Law 1, p. 34.

[41] For example, in the current PG&E Phase 2 General Rate Case (A.19-11-019), the settlement proposal includes a small commercial rate with strong marginal cost-based TOU differentiation (Schedule B-6).

guiding principles and enhances the opportunity for NEM systems to drive down system costs and emissions.

SBUA proposes that customers who install NEM-paired storage systems would have a choice. The customer could choose to configure and meter the NEM-paired storage system to ensure that NEM credit could only be earned by eligible renewable electric generation and would then be treated in the exact same manner as any customer who does not have NEM-paired storage.

Customers could alternatively choose a simpler configuration for their storage system that would allow charging from either the NEM generation or the grid, such that:

- The storage system would not comply with California Energy Commission (CEC) RPS eligibility guidelines, making the entire system ineligible for RPS credit; and
- All generation (non-storage) resources utilized under a NEM tariff would still need to meet the CEC RPS eligibility guidelines, notwithstanding ineligibility for RPS credit.

Customers choosing to charge from the grid would be required to utilize daily netting to maximize system benefits from this more flexible option.

We also highlight the importance of furthering support for customer investment in resilience, particularly for critical facilities. SBUA's proposal would increase the likelihood that nonresidential critical facilities would invest in NEM-paired storage systems, increasing their resilience during power supply disruptions and reducing the utility's challenge to restore service.

B. Netting Process by Customer Group

Q: Why should some customer groups be allowed to use monthly or annual netting periods for generation-only NEM systems?

A: As discussed above, in order to "ensure equity among customers" as indicated by Guiding Principle B, the NEM successor tariff should enhance the opportunity for growth in NEM systems serving disadvantaged and small businesses. As solar and storage are more widely implemented for these customer groups, the Commission can adjust the net-metering rules to balance continued growth with system costs and benefits.

As shown in Table 6, we recommend that customers meeting disadvantaged community standards, small businesses, and critical facilities[42] (without NEM-paired storage systems) should remain on the annual TOU netting period. However, to better balance system costs and benefits, large commercial, and any customers with systems larger than 1 MW (but without NEM-paired storage systems) should be switched to a monthly netting period. As discussed in the previous section, customers who choose to utilize grid-supplied power for charging would use daily TOU period netting.

We have also included residential customers as among those who would remain on monthly netting initially. The strong market for non-CARE residential solar systems suggests that this market is well-positioned to transition quickly to daily TOU netting. However, in the interests of sustaining the customer-sited solar market through the transition to a NEM successor tariff, we recommend that the transition

[42] SBUA recommends the Commission define critical facilities using the list adopted by D.19-05-042 or in subsequent decisions. As the Commission discussed in D.21-01-018, modifications to the critical facility list should be pursued through the avenues contemplated under D.19-05-042, as deviations from that list would create regulatory confusion and uncertainty.

from monthly to daily TOU netting be deferred until it is clear that the market has adjusted to the new economics.

We further recommend that the Commission conduct periodic reviews to determine when equitable growth for each customer category may be maintained using a shorter netting period. As shown in Table 6, each customer category would progress from annual, to monthly, and then to daily netting periods at a category-specific pace. This could be done on a statewide basis, but there may be good cause to allow differences across the three IOUs.

Table 6: Proposed Initial and Final Netting Periods, by Customer Category

Customer Category	Initial Netting Period		Final Netting Period
	No Grid Storage	Storage	
Residential	Monthly	Daily	Daily
Disadvantaged Community[43]	Annual	Daily	Daily
Small Business < 500 kW	Annual	Daily	Daily
Critical Facilities[44]	Annual	Daily	Daily
All Other Commercial	Monthly	Daily	Daily
All Systems > 1 MW	Monthly	Daily	Daily

[43] Including customers on CARE or FERA rates, and NEM-qualified systems funded through SASH, MASH, and SOMAH. SBUA has not analyzed whether it would be appropriate to include customers on Green Tariffs.

[44] SBUA recommends the Commission define critical facilities using the list adopted by D.19-05-042 or in subsequent decisions. As the Commission discussed in D.21-01-018, modifications to the critical facility list should be pursued through the avenues contemplated under D.19-05-042, as deviations from that list would create regulatory confusion and uncertainty.

We include the category of critical facilities due to the proceedings such as SGIP (R.20-05-012) and Microgrid Commercialization (R.19-09-009) in which the Commission is considering measures to encourage customer investment in resilience, particularly for critical facilities. Our proposal would increase the likelihood that nonresidential critical facilities would invest in NEM-paired storage systems, increasing their resilience during power supply disruptions and reducing the utility's challenge to restore service.

Virtual Net Energy Metering (VNEM) and NEM Aggregation (NEMA) systems should be treated similarly to behind-the-meter NEM. For example, residential VNEM or NEMA systems without storage should be transitioned to a monthly TOU netting period unless the customers or the system qualifies under the disadvantaged community category.

SBUA is not proposing any changes to the following elements of the NEM 2.0 Tariff.

- Interconnection fees should continue to be assessed on the same basis and waived for certain low-income and disadvantaged customers.
- Generation from NEM systems should not be subject to any departing load charges, although nonbypassable charges should continue to be applied to all grid-supplied power irrespective of exported power used for netting credit.
- Systems 1 MW or larger should continue to be treated identically to smaller systems and interconnection costs should continue to be project-specific, except that a monthly netting period should be used for non-storage systems, irrespective of customer category.
- Other than application of monthly netting periods, special rules and methods for net energy metering aggregation and virtual net energy metering should be maintained.

C. NEM Generation Charge

Q: Why do you suggest that the Commission approve a NEM generation charge?

A: A charge for generation-only NEM system capacity would address two concerns. First, it would encourage solar customers to install storage, which has multiple system-wide benefits. Second, the charge would reduce the revenue transfer from NEM customers to other customers.

In general, we do not support charging customers for utility services that they do not use as a result of reduced need for grid-supplied energy. In this situation, the need to direct solar customers toward storage and the pressure to reduce revenue requirements for non-DER customers justifies a NEM generation charge. Our proposed NEM generation charge would resemble existing standby charges, but with significant differences.

Q: How should the Commission set a NEM generation charge?

A: The Commission should open a Phase 2 of this proceeding to determine the specific costs that should be included in a NEM generation charge. As discussed above, a Proposed Decision in the Senate Bill 1339 Microgrid OIR proceeding puts forward an insightful analysis of the relationship between the character of capacity self-supplied by customer-generators to the need for back-up capacity provided by the load serving entity.

In the Proposed Decision, the ALJ finds that DERs that "can demonstrate high availability and high reliability" merit a suspension of the "capacity reservation component of the standby charge."[45] Solar-plus-storage systems meet the test of high

[45] Proposed Decision of ALJ Rizzo, *Decision Adopting a Suspension of the Capacity Reservation Component of the Standby Charge for Eligible Microgrid Distributed Technologies* (June 9, 2021), R.19-09-009, p. 27.

availability and high reliability, especially on an aggregate basis, while solar-only NEM systems do not.

Following the same logic, in a Phase 2 of this proceeding, the Commission should determine the appropriate cost basis for a NEM generation charge and establish specific performance standards for full or partial waiver of the NEM generation charge. In determining the appropriate cost basis, the Commission should recognize that short-term fluctuations in individual customers' net load, as refrigerators and air conditioners switch on and off, have little effect on generation loss-of-load-expectation (LOLE) or cost, or distribution overloads, which are significant over multiple hours. Effectively, individual customers balance out each other's short-term fluctuations in net load; system costs reflect the aggregate effect of many individual NEM customers.

Thus, while we believe that the existing cost basis for standby charges is an appropriate starting point for discussion, the Commission should ensure that the NEM generation charge does not over-recover costs by treating each individual NEM customer as a customer-generator who requires full generation backup by the utility. Determining an appropriate method should be considered in a Phase 2 of this proceeding, followed by individual applications by the IOUs to set cost-based rates.

In order to estimate the potential impact of a NEM generation charge on residential and commercial NEM customers, we adopted the values proposed by the Joint IOUs for "Grid Charges." Our adoption of those values is for illustrative purposes only, and does not imply support for the Joint IOUs' proposed cost basis for their Grid Charges.

Q: How do you propose that the NEM generation charge be applied?

A: We suggest that the NEM generation charge be applied to the difference between the solar inverter AC capacity and one half the battery storage system's energy storage capacity (again, in AC terms). Thus, the system must have at least two hours of storage to entirely avoid the NEM generation charge. For solar coupled to the battery through a direct-current connection and sharing an inverter, the charge would be applied to the difference between the solar array's DC capacity and one half the battery storage system's DC energy storage capacity, times the ratio of the inverter AC capacity to the solar DC capacity.

In Table 7, we have illustrated the application of the NEM generation charge to a 4 kw-AC solar system. Without any storage, the system would be charged based on its 4 kW size. To fully avoid the NEM generation charge, the system would be required to have battery storage capable of storing 8 kWh.

Table 7: Example of NEM Generation Charge for a 4 kW-AC Solar System

Storage Duration	1 kW	2 kW	4 kW
1 hour	3.5 kW	3 kW	2 kW
2 hour	3 kW	2 kW	0 kW

D. Evaluation of Proposed NEM Successor Tariff

Q: Please summarize the results of your evaluation.

A: We evaluated our proposal using a modified version of the CPUC Residential and Commercial Bill Models. Our modifications are described in Section 0.

As shown in Table 8 and Table 9, our proposal has the following results for residential non-CARE customers, compared to the NEM 2.0 findings from Table 16 in the E3/Verdant cost-effectiveness study.

- Payback periods for solar-only systems are roughly doubled, and the PCT score is cut roughly in half. This means that solar-only systems will be less attractive under our proposal than under NEM 2.0.
- Payback periods for solar-plus-storage systems are lower than for solar, and the PCT scores are slightly higher. This indicates that customers would see a financial advantage to including NEM-paired storage.
- The TRC scores for the SBUA solar-plus-storage proposal are higher than for NEM 2.0 because our storage dispatch algorithm is designed to maximize customer bill savings. Because residential EV rates used in our modeling have strong price differentiation between TOU rate periods, our storage algorithm shifted both solar-charged and grid-charged power from off-peak to on-peak and part-peak periods. This arbitrage tends to result in more favorable avoided cost savings.
- The TRC scores for the SBUA proposal are near or above 1.0 by 2030, indicating that our proposal should be cost-effective by the late 2020s.
- RIM scores for the SBUA proposal are roughly double those for the NEM 2.0 evaluation of solar-only systems, and significantly higher for the solar-plus-storage systems.

Further details from our model results are attached in Exhibit RII-3 (Residential Model Results) and Exhibit RII-4 (Commercial Model Results).

These model results suggest that the SBUA proposal for a NEM successor tariff is likely to result in the majority of NEM systems having a TRC score of 1.0 or greater. Some individual scores are above 1.0, and others are lower. Our exploration of the E3/Verdant model indicates that a major factor in the model results is the underlying rate design from each utility, which we will discuss below.

One reason our proposal will raise TRC scores is that the participant cost measures for solar+storage systems beat solar alone in our proposal, while solar alone is more favorable than solar+storage under NEM 2.0. More favorable economics for storage could promote a shift toward NEM-paired storage, and thus a higher

weighting of those systems, which have higher TRC scores, should result in a more cost-effective NEM program.

We also expect that due to (a) somewhat reduced adoption due to the higher costs of solar-plus-storage systems and less favorable economics of solar systems and (b) the higher RIM test results for our proposal (particularly solar-plus-storage), impacts on non-participants will be substantially reduced compared to NEM 2.0.

Table 8: Model Evaluation Results for Non-Care Residential Customers (2023)

IOU	Payback Period (years)	First-Year Cost Shift	PCT	RIM	TRC
SBUA Solar					
PG&E	8.2	$ 812.74	1.80	0.20	0.36
SCE	13.1	$ 283.14	1.09	0.52	0.58
SDG&E	6.8	$ 1,001.90	2.20	0.18	0.39
NEM 2.0 Solar[46]					
PG&E	4.5	$ 1,817	3.28	0.11	0.36
SCE	5.4	$ 1,287	2.74	0.21	0.58
SDG&E	3.3	$ 2,448	4.49	0.09	0.39
SBUA Solar+Storage					
PG&E	6.5	$ 1,588	2.10	0.27	0.57
SCE	7.3	$ 1,133	1.90	0.46	0.88
SDG&E	4.6	$ 2,229	2.90	0.23	0.67
NEM 2.0 Solar+Storage[47]					
PG&E	6.0	$ 1,791	2.27	0.22	0.50
SCE	6.3	$ 1,406	2.14	0.38	0.83
SDG&E	4.2	$ 2,490	3.14	0.20	0.63

The SBUA Solar result for 2023 includes the effect of a daily TOU netting period. We propose initially offering a monthly TOU netting for a brief transitional period until the market has adjusted to the NEM successor tariff. We present the daily

[46] E3/Verdant Report, Table 16, p. 53.

[47] E3/Verdant Report, Table 17, p. 54.

TOU netting period results here because we expect the transition to occur within two years. The transition period does not affect any other aspect of our proposal.

Table 9: Model Evaluation Results for Non-Care Residential Customers (2030)

IOU	Payback Period (years)	First-Year Cost Shift	PCT	RIM	TRC
SBUA Solar					
PG&E	4.9	$ 1,337	3.07	0.20	0.63
SCE	8.1	$ 434	1.89	0.55	1.05
SDG&E	4.0	$1,527	3.76	0.19	0.73
NEM 2.0 Solar[48]					
PG&E	2.7	$ 2,651	5.52	0.11	0.63
SCE	3.2	$ 1,788	4.63	0.22	1.05
SDG&E	1.9	$ 3,407	7.55	0.09	0.73
SBUA Solar+Storage					
PG&E	4.7	$ 1,968	3.12	0.30	0.95
SCE	5.3	$ 1,106	2.80	0.53	1.51
SDG&E	3.3	$ 2,631	4.44	0.28	1.28
NEM 2.0 Solar+Storage[49]					
PG&E	4.4	$ 2,311	3.37	0.24	0.83
SCE	4.6	$ 1,474	3.17	0.44	1.40
SDG&E	3.1	$ 3,027	4.73	0.23	1.09

Q: Please explain why you believe the underlying rate design is a major factor in NEM program cost-effectiveness.

A: As shown in Table 8 and Table 9, there is substantial variation in the results among the utilities. The degree of time-differentiation in each utility's rates, as well as how well the TOU periods align with avoided costs, can have substantial effects. This is demonstrated in the commercial model results (Exhibit RII-4).

[48] E3/Verdant Report, Table 20, p. 57.

[49] E3/Verdant Report, Table 21, p. 58.

In the commercial model, we found that the TRC and RIM scores were slightly worse after modifying the model to use a storage algorithm that maximized customer bill savings. This counter-intuitive finding contrasted sharply with the residential model findings, which showed that TRC and RIM scores improved with our algorithm.

Our investigation into the commercial bill model was limited by the testimony deadline, but it appears that the E3/Verdant storage algorithm dispatches energy from storage in a manner that does not maximize bill savings. For example, we observed a model day in which the battery storage was dispatched far in excess of customer load for two hours during the peak period. In the SBUA proposal, as in that of many other parties, that power would be compensated at avoided costs. A customer is more likely to reserve that power and dispatch it over several hours to offset customer load, which would reduce the customer's billing at peak rates.

Overall, our storage algorithm increased bill savings but slightly decreased TRC savings, due to problems in the underlying rate designs. We believe our algorithm is a more accurate reflection of how a customer would dispatch storage energy than the storage algorithm provided by E3/Verdant.

Another reason that our algorithm had limited impact on the RIM and TRC scores in the commercial model is that the rates in the commercial model have less time differentiation.

- In the residential model, PG&E's EV2A-TOU-NEM2 rate is about 21 cents per kWh higher in the summer peak than in the summer off-peak.
- In the commercial model, PG&E's B-1 rate is only about 7 cents per kWh higher in the summer peak than in the summer off-peak.

SDG&E had a similarly less-differentiated commercial rate. SCE's commercial rate has TOU differentiation that is similar to its residential rates; improving the modeling does not reduce the RIM and TRC scores as much for SCE as for PG&E or SDG&E.

In general, the IOUs are adopting rates with greater TOU period differentiation, which should improve NEM TRC and RIM scores, especially for NEM proposals that take advantage of storage arbitrage.[50]

Furthermore, the 4 PM – 9 PM peak TOU periods used in current rates are not well-aligned with 2030 avoided costs. As shown in Figure 4, to align peak TOU periods with 2030 avoided cost rates, the peak periods should be shifted at least one hour later, to 5 PM – 10 PM. Notably, the single highest hour occurs 10–11 PM in September.

Figure 4: Average Avoided Costs by Month and Hour Beginning for 2030

	Weekday Hours																Peak TOU Period							
Months	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.07	0.08	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.06	0.07	0.06	0.05	0.06	0.05	0.09	0.19	0.24	0.12	0.08	0.08	0.13	0.14	0.08
2	0.07	0.08	0.07	0.07	0.07	0.08	0.11	0.09	0.06	0.04	0.05	0.03	0.02	0.04	0.04	0.04	0.12	0.16	0.13	0.12	0.12	0.17	0.13	0.09
3	0.08	0.07	0.05	0.06	0.06	0.07	0.10	0.11	0.05	0.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.01	0.09	0.17	0.25	0.23	0.16	0.10	0.07
4	0.02	0.05	0.07	0.05	0.02	0.07	0.05	0.08	0.02	-0.01	-0.01	-0.01	-0.01	0.02	-0.01	-0.01	0.02	0.01	0.05	0.18	0.25	0.12	0.05	0.04
5	0.04	0.02	0.02	0.02	0.03	0.02	0.03	0.10	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.06	0.10	0.12	0.24	0.15	0.10	0.07
6	0.06	0.04	0.04	0.04	0.04	0.06	0.09	0.11	0.04	0.03	0.01	0.00	0.01	0.01	0.02	0.03	0.06	0.16	0.21	0.22	0.30	0.22	0.12	0.08
7	0.05	0.03	0.03	0.05	0.02	0.06	0.04	0.06	0.03	0.00	0.00	-0.01	0.00	0.00	0.02	0.08	0.17	0.24	0.30	0.32	0.44	0.22	0.13	0.09
8	0.07	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.06	0.04	0.04	0.03	0.04	0.05	0.06	0.07	0.16	0.20	0.25	0.50	0.35	0.10	0.10	0.08
9	0.09	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.05	0.03	0.03	0.01	0.02	0.03	0.04	0.06	0.07	0.10	0.28	0.65	0.30	0.33	1.00	0.37
10	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.09	0.06	0.05	0.04	0.02	0.02	0.02	0.03	0.07	0.09	0.12	0.26	0.20	0.13	0.13	0.09	0.08
11	0.07	0.08	0.07	0.09	0.06	0.07	0.10	0.07	0.04	0.03	0.02	0.02	0.02	0.02	0.04	0.08	0.12	0.12	0.13	0.13	0.22	0.13	0.08	0.07
12	0.07	0.07	0.07	0.07	0.07	0.11	0.10	0.10	0.08	0.06	0.06	0.06	0.05	0.05	0.05	0.07	0.22	0.15	0.20	0.12	0.13	0.11	0.09	0.08
	Weekend Hours																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.14	0.09	0.08	0.08	0.07	0.07	0.08	0.08	0.07	0.07	0.05	0.04	0.04	0.05	0.05	0.08	0.10	0.20	0.08	0.10	0.11	0.13	0.08	0.08
2	0.13	0.10	0.07	0.08	0.08	0.08	0.11	0.07	0.04	0.01	0.01	0.01	0.01	0.02	0.01	0.02	0.05	0.20	0.14	0.10	0.10	0.14	0.07	0.07
3	0.11	0.10	0.06	0.07	0.08	0.09	0.09	0.09	0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.00	0.03	0.15	0.15	0.17	0.10	0.10	0.06
4	0.02	-0.01	0.01	0.01	0.00	0.10	0.03	0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.13	0.13	0.22	0.14	0.04	0.00
5	0.05	0.12	0.06	0.04	0.04	0.05	0.09	0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.03	0.02	0.10	0.09	0.18	0.14	0.10	0.06
6	0.06	0.14	0.05	0.06	0.04	0.06	0.04	0.04	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.02	0.13	0.07	0.11	0.26	0.23	0.15	0.08	0.06
7	0.05	0.20	0.06	0.07	0.03	0.01	0.04	0.03	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.03	0.11	0.20	0.21	0.30	0.18	0.12	0.06
8	0.07	0.10	0.06	0.11	0.08	0.08	0.08	0.04	0.00	0.01	0.00	0.00	0.02	0.05	0.05	0.09	0.14	0.20	0.33	0.42	0.43	0.17	0.11	0.07
9	0.07	0.09	0.08	0.09	0.09	0.12	0.09	0.06	0.03	0.01	0.01	0.00	0.00	0.01	0.02	0.04	0.08	0.19	0.25	0.31	0.14	0.12	0.10	0.07
10	0.08	0.12	0.09	0.08	0.07	0.09	0.09	0.07	0.05	0.02	0.01	0.01	0.02	0.01	0.02	0.04	0.16	0.13	0.15	0.15	0.10	0.11	0.07	0.10
11	0.10	0.08	0.09	0.08	0.08	0.09	0.10	0.06	0.03	0.03	0.01	0.01	0.01	0.01	0.02	0.05	0.10	0.15	0.14	0.14	0.11	0.08	0.07	0.11
12	0.07	0.10	0.12	0.07	0.07	0.07	0.08	0.08	0.07	0.06	0.06	0.05	0.04	0.04	0.04	0.12	0.23	0.07	0.07	0.07	0.14	0.07	0.07	0.07

In summary, we believe that by the time the NEM successor tariff is put into effect, the underlying rates will be more time-differentiated, resulting in higher TRC and RIM scores for NEM proposals (as well as better participant-cost scores). Combined with the likelihood of shifting TOU periods at least one hour later in future

[50] Our proposal includes a requirement that NEM customer groups required to use daily TOU netting must also be on an underlying tariff that includes strong TOU rate differentiation.

general rate cases, the performance of a storage-optimized NEM tariff should improve significantly.

Q: How would small businesses be impacted by your proposal?

A: Due to the problems we identified with the underlying rate designs, particularly for PG&E and SDG&E, the commercial modeling results (Exhibit RII-4) do not suggest that small businesses would be much more likely to adopt NEM-paired storage systems than they are currently likely to adopt solar systems. However, as greater time differentiation in rates becomes available, we anticipate that solar+storage systems could be more attractive to small businesses.

Small businesses will also benefit from the reduced non-participant impacts from residential solar-only customers as our proposed NEM tariff incentivizes a shift towards solar+storage systems.

Q: What findings and recommendations should the Commission adopt with respect to the analyzing NEM successor tariff proposals?

A: The Commission should adopt the following findings.

1. SBUA's proposal for a NEM successor tariff is reasonable for the following reasons.
    a. Netting imports and exports using a daily TOU period retains the concept of "net energy" which promotes stability in rate design. Short-term fluctuations in individual customers' net load have little effect on generation cost or distribution overloads, which are significant over multiple hours. A very short-term netting period (or no netting period at all) would encourage customers to waste resources on enabling technologies to smooth out variations that are inconsequential to system costs.
    b. Compensation of exports at a rate lower than the import rate (excluding non-bypassable charges) would result in a lower roundtrip rate differential. Smaller rate differentials reduce the economic incentive to install NEM-paired storage.
    c. Allowing NEM 2.0 netting practices to remain in effect for customers in disadvantaged communities and small business customers will help ensure

continued growth of distributed generation (DG) in those customer groups. Among those customer groups, critical facilities should also be considered a customer group for these purposes. A glide path to transition these customer groups to daily TOU period netting will balance the objectives of continued growth with balancing system costs and benefits.

d. Virtual Net Energy Metering (VNEM) and NEM Aggregation (NEMA) systems should be treated similarly to behind-the-meter NEM.

e. Requiring NEM customer groups who have been transitioned to daily TOU netting periods should be required to utilize a rate with strong marginal cost-based TOU differentiation. Since the IOUs are moving to mandatory TOU or critical peak pricing (CPP) rate designs, the Commission should mandate the most effective forms of these pricing signals for NEM systems in order to promote the installation of NEM-paired storage.

f. Removing the restriction on grid charging of NEM-paired storage systems will further leverage TOU and CPP rate designs. The benefit of allowing NEM customers to

g. A NEM generation charge assessed on the generation resource capacity in excess of the NEM paired-storage resource is appropriate because it will encourage customers to purchase storage systems, with multiple system-wide benefits, and because it will reduce revenue transfer from NEM customers to other customers.

h. Additional information is required to develop the cost basis for a NEM generation charge, since there are significant differences between NEM systems and larger systems that are subject to standby charges. NEM systems can demonstrate a high level of availability and reliability, particularly in the context of system impacts which are best measured in the aggregate, and not for individual customers.

i. Modeling of the SBUA proposal indicated that due to increased payback periods for solar-only systems, those systems will be less financially attractive than under NEM 2.0.

j. Modeling of the SBUA proposal indicated that payback periods for solar-plus-storage systems are lower than for solar, and thus customers would see a financial advantage to including NEM-paired storage.

k. The TRC scores for the SBUA proposal are higher than for NEM 2.0 because the storage dispatch will shift both solar-charged and grid-charged energy from off-peak to peak periods, reducing system costs.

l. The TRC scores for the SBUA proposal are near or above 1.0 by 2030, indicating that it should be cost-effective by the late 2020s

m. RIM scores for the SBUA proposal are roughly double those for the NEM 2.0 evaluation of solar-only systems, and significantly higher for the solar+storage systems. Combined with the shift in customer adoption

towards solar+storage systems, impacts on non-participants could be substantially reduced compared to NEM 2.0.

2. The Commission should continue to guide rate design towards rates with cost-based TOU differentiation to provide the strongest possible price signals for customer use of NEM paired-storage systems.
3. The following elements of the NEM 2.0 tariff do not require any changes.
    a. The annual "net surplus compensation" method.
    b. Interconnection fees.
    c. Non-application of departing load charges.
    d. Treatment of systems larger than 1 MW.
    e. Special rules and methods for net energy metering aggregation and virtual net energy metering.

We also suggest that the Commission consider relevant findings from our discussion of the guiding principles and statutory requirements in Section X. The Commission should adopt the following recommendations.

1. Adopt SUBA's proposed NEM successor tariff.
2. Establish a process for periodic reviews to determine when equitable growth for each customer category may be maintained by using a shorter netting period. The netting period for residential non-CARE customers should be transitioned from monthly to daily only one or two years after implementation of the NEM successor tariff.
3. Open a Phase 2 of this proceeding to determine the specific costs that should be included in a NEM generation charge and establish specific performance standards for full or partial waiver of the NEM generation charge based on the capacity of NEM paired-storage systems.

VIII. Modeling of Proposed NEM Successor Tariff

Q: Please describe the modeling you did of the Proposed NEM successor tariff.

A: We modified the E3/Verdant model provided by CPUC staff to correct coding errors and to fully reflect our proposal. As stated in the E3 report:

SBUA specified that there would be no limitation to charging storage from the grid. The storage charging and discharging shape used in the modeling was developed did not allow for charging from the grid. See the "Representative customers" section for more detail on the storage shapes used in the model.

In addition to creating a storage algorithm that allowed for charging from the grid, our storage algorithm was customized to optimize charging from solar power as well, reflecting comparisons among rates and taking into consideration the round-trip-efficiency of storage systems.

We also modified the proposal to reflect our NEM generation charge, which we determined would be an appropriate policy to include in our proposal after the deadline for submitting modeling details.

Finally, we also modified the model for certain analyses to reflect the transition from annual to monthly, and then to daily netting. The resulting residential and commercial models are provided as Exhibits RII-5 and RII-6, respectively.

Q: Please summarize the coding errors you corrected.

A: We corrected the following errors.

- The SDG&E DWR bond charge error identified by E3/Verdant in their updated report was corrected by increasing the NBC component of SDG&E rates by $0.0058 on the Import Rates tab of the residential and commercial models.
- The SDG&E EV weekend TOU period error identified by E3/Verdant in their updated report was corrected by updating the TOU period table on the Import Rates tab of the residential model.
- The formulas in the residential and commercial models, Customer Bill Components tab, for Exports Below Imports and Exports Above Imports checked for Daily Netting incorrectly. We updated the formulas to check whether if the cell value is the logical value TRUE rather than the text string "TRUE".
- The days and months for several holidays and daylight savings time were entered incorrectly on the Lists tab for both the residential and commercial model. For example, daylight savings time was listed in columns AN-AP as beginning on 11-23-2020 and ending on 12-25-2020.

Q: Please describe your storage algorithm.

A: Our storage algorithm includes the following steps.

- Solar is reserved to meet customer load first. Since netting within the TOU period is allowed, we compare total load to generation during the hours with solar generation. If there is an excess of generation (negative net load) during those hours, then solar charging is allowed. Otherwise, the model assumes that any solar exports will be below imports and compensated at a rate of imports minus NBCs.
- The surplus power is adjusted for round trip efficiency.
- The amount of power stored in the solar system is the hourly surplus power (negative net load).
- If it is a peak period, and there is net load, then power is discharged up to the limit of the amount stored in the battery at the beginning of the hour.
- During the last hour of the peak period, there is an economic test to determine if power should be discharged at the peak period avoided cost rate, or if it should be retained to offset part-peak load.
- The potential for charging the battery with grid storage is assessed by considering the remaining load, net of solar and solar-charged storage. If there is unmet load during the peak period (and, separately, part-peak period), an economic test verifies that it is in the customer's interest to charge the battery at off-peak import rates and then discharge the battery to avoid on-peak rates, after considering round-trip efficiency losses. Grid charging is limited to the available capacity of the battery after storing solar power.

We also made adjustments to address issues such as rates without peak periods, two-part rates, and irregular sequencing of TOU periods at the summer/winter boundary,

Q: Please describe how you modeled the NEM generation charge.

A: As discussed above, we adopted values equal to the Joint IOUs Grid Charge proposal, applied to the solar-only cases.

Q: Please explain how you modeled the transition between annual, monthly, and daily netting.

A: As shown in Exhibit 3, for the residential non-CARE customer case, we modeled a 2023 case with monthly and daily netting in order to identify the impact on cost-

effectiveness scores. The change did not significantly affect RIM or TRC scores. The transition to the daily netting case increased the payback period by several months, reduced the first-year cost shift, and reduced the PCT score. Because these effects were small (but significant), we concluded that it would be reasonable for the Commission to begin with monthly TOU netting but quickly transition to daily TOU netting for residential non-CARE customers.

For all other cases, we modeled our initial and final proposals (as shown in Exhibits 3 and 4) in 2023 and 2030, respectively.

IX. Other Issues

Q: Do you have comments on any other issues related to current net energy metering tariffs and subtariffs?

A: Yes. We see little justification for off-site virtual net energy metering tariffs, other than for low-income and disadvantaged communities who may not have access to NEM due to historic discrimination in both home and commercial buildings.

On the other hand, on-site net energy metering aggregation is important to customers in multi-tenant buildings, for both multi-family properties and small-commercial customers in office buildings, malls, shopping centers and other facilities in which directly wiring DER behind individual customer meters would be impractical.

We see little economic justification for the Renewable Energy Self-Generation Bill Credit Transfer. However, so long as the credit transfer applies only to local governments and/or college campuses, to allow them to apply excess generation at one point in their facilities to load in other facilities, and so long as the Commission

finds that these are disadvantaged customers deserving of preferential treatment, we have no objection to continuation of the program for a period of time.

We recommend aligning the treatment of exported power (after any transfers to other associated facilities within the TOU billing period) with our proposal for the NEM successor.

X. Compliance with Statutory and Commission Standards

Q: What statutory requirements are relevant to your proposal?

A: The guiding principles (D.21-02-007) direct that the "successor to the net energy metering tariff should comply with…Public Utilities Code Section 2827.1," which lays out the following standards:

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.
2. Establish terms of service and billing rules for eligible customer-generators.
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.
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.
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.
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.

Q: How does your proposal ensure "that customer-sited renewable distributed generation continues to grow sustainably?"

A: While no rate design can ensure customer response *a priori*, our proposal targets payback periods that will slow growth in customer-sited renewable distributed generation compared to NEM 2.0 rates, but will still allow substantial growth.

Q: How does your proposal address residential customers in disadvantaged communities?

A: The current NEM netting period would remain in effect for California Alternate Rates for Energy Program (CARE), Family Electric Rate Assistance Program (FERA) customers and small commercial customers for solar-only installations, with an enhanced offer for solar-plus-storage systems.

PUC §2827.1(b)(1) requires the Commission to ensure that the NEM tariff includes "specific alternatives designed for growth among residential customers in disadvantaged communities." It appears that California is falling short of meeting that goal, as the Lookback Study found that "areas with higher incomes show higher percentages of NEM installations relative to California's population," and that since the implementation of NEM 2.0 tariffs, the adoption rate of NEM systems in disadvantaged communities has shown some decrease.

Non-residential customers have also largely been absent from participation in the NEM tariff. According to the Lookback Study, even though non-residential systems are roughly five times larger than residential systems, since they represent roughly 2% of the total market, non-residential systems generate only about 10% of total NEM system output.

Small businesses that own their property are good candidates for NEM systems, particularly with storage. Small or medium-sized business businesses (SMBs) that own their property tend to pay their own electric bills and are likely to be good candidates for a solar-plus-storage installation. A survey of SMBs in the nine-county San Francisco Bay Area found that over three-quarters of them owned, managed, and occupied the entire building.[51] Tenants in office buildings or shopping centers will need to work with the property manager to benefit from NEM systems; program design to encourage such collaboration is beyond the scope of this proceeding.

Thus, in order to "ensure equity among customers" as promoted by Guiding Principle B, the NEM successor tariff should enhance the opportunity for growth in NEM systems serving disadvantaged and non-residential customers, especially small businesses.

Q: Does your proposal address "terms of service and billing rules for eligible customer-generators"?

A: Not in detail. This should be addressed in a Phase 2 of this proceeding following the Commission's decision to adopt a NEM successor tariff proposal.

Q: How is your proposal "based on the costs and benefits of the renewable electrical generation facility?

A: Our proposal is likely to have among the highest TRC scores due to promotion and enhanced utilization of NEM-paired storage.

[51] Applied Energy Group, *BayREN SMB Non-Deemed Market Characterization Study*, CALMAC Study ID BAR0001-01 (July 26, 2018), p. 8.

Q: How does your proposal "ensure that the total benefits…are approximately equal to the total costs"?

A: As discussed above, our proposal has a TRC score that is higher than many other proposals because NEM-paired storage may both charge from and export to the grid, increasing the value of the DER to the system as a whole. Including the value of resiliency, the benefits would be even larger.

Q: Does your proposal "allow projects greater than one megawatt…to be built to the size of the onsite load," with appropriate interconnection requirements?

A: Yes. This statutory criterion was met by the NEM 2.0 decision (D.16-01-044) and we do not recommend any changes.

Q: What transition periods do you propose for customers on NEM 1.0 and NEM 2.0?

A: We support the idea that customers on NEM 1.0 and NEM 2.0 could be transitioned to the NEM successor tariff after the Commission determines that the majority of customers have been on the older tariff long enough to pay back the investment for most customers. We have not examined this issue in detail, but anticipate that other parties will provide testimony on this issue.

Q: In addition to the statutory requirements, what are the other guiding principles that proposals are required to address?

A: The remaining seven guiding principles are:

(b) A successor to the net energy metering tariff should ensure equity among customers;

(c) A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services;

(d) 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;

(e) 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, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18;

(f) 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;

(g) 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; and

(h) A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.

Q: Would your proposal ensure equity among customers?

A: Our proposal would advance equity by providing more favorable economics for customer groups that are currently disadvantaged.

Q: Does your proposal "enhance consumer protection measures for" NEM customers?

A: No. Our proposal does not enhance or degrade consumer protection measures. This topic should be addressed in a Phase 2 of this proceeding following the Commission's decision to adopt a NEM successor tariff proposal.

Q: Does your proposal cover "all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1"?

A: Yes. Our analysis focuses on solar and storage technologies, which have dominated and are likely to continue to dominate behind-the-meter renewable generation.

Q: Is your proposal consistent with the Commission and California's energy policies?

A: Yes. We have discussed how our proposal would sustain the growth of behind-the-meter renewable generation and storage and increase resilience. By increasing the amount of customer-sited DERs, our approach would tend to minimize pressure on open space for utility-scale solar and transmission for energy imports.

Q: Would your proposal "be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities"?

A: We expect that our proposed rates would be transparent and understandable. The details of communicating the successor rates to customers should be addressed in a Phase 2 of this proceeding following the Commission's decision to adopt a NEM successor tariff proposal. We propose the same approach for all utilities; the details will vary due to existing rate designs and other utility-specific differences in loads and resources.

Q: Would your proposal "maximize the value of customer-sited renewable generation to all customers and to the electrical system"?

A: Maximizing value has at least three components: maximizing installation of behind-the-meter generation, encouraging the installation of the types of generation that are most beneficial, and encouraging customers to shift load and generation to reduce costs and increase reliability.

There is a trade-off between maximizing the value of renewable generation and minimizing the rate effects on non-participating customers. We have attempted to strike a reasonable balance between those considerations. As indicated by the PCT and payback scores, our proposal strongly encourages customers installing behind-

the-meter solar to add storage, which enhances value to the system and other customers.

Finally, once a solar or solar-plus-storage system is installed, our proposal encourages customers to shift their consumption to lower-cost, higher-solar times and to shift their battery discharge to the higher-cost, lower-solar, high-load periods.

Q: Does your proposal result in competitive neutrality amongst Load Serving Entities.

A: Not inherently, although we do not expect that it would be difficult to achieve competitive neutrality. The coordination of rates between the IOUs, CCAs and other LSEs should be addressed in a Phase 2 of this proceeding following the Commission's decision to adopt a NEM successor tariff proposal.

Q: Does this conclude your testimony?

A: Yes.