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Exhibit Number	:	PAO-01
Commissioner	:	Guzman Aceves
Admin. Law Judge	:	Kelly Hymes
Public Advocates Project Mgr.	:	Alec Ward
Public Advocates Witnesses	:	Adam Buchholz
	:	Sophie Babka
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		Nathan Chau
		Kristin Rounds

PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY FOR A SUCCESSOR TARIFF TO THE CURRENT NET ENERGY METERING TARIFFS

San Francisco, California
June 18, 2021

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MEMORANDUM

This report was prepared by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) in Rulemaking (R.) 20-08-020. On November 11, 2020, Assigned Commissioner Martha Guzman Aceves and Administrative Law Judge (ALJ) Kelly Hymes released the Joint Scoping Memo in R.20-08-020, which requested opening testimony on a successor to the current Net Energy Metering (NEM) tariff, developed pursuant to Assembly Bill 327 (Perea, 2013). In this report, Cal Advocates presents its analysis and recommendations for a successor tariff.

Alec Ward served as Cal Advocate's project coordinator in this review and is responsible for the overall coordination in the preparation of this report. Cal Advocates' witnesses sponsoring each chapter or section are identified at the beginning of each section. Witnesses' prepared qualifications are contained in Appendix A of this report.

CHAPTER 1 EXECUTIVE SUMMARY

(Witness: Alec Ward)

I. INTRODUCTION

Cal Advocates hereby submits this opening testimony (Testimony) in response to the *Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles* (Scoping Memo) requesting parties submit opening testimony on successor tariffs to the current NEM program.[1] Much of the text reflects the content of our party proposal (Proposal),[2] but supplements or updates the Proposal with additional position refinements and evidence. New topics include successor tariff proposal cost-effectiveness, further evidence for and details regarding a Grid Benefit Charge and an Equity Charge, and further details of a transition incentive policy proposal. Overall, Cal Advocates' Testimony addresses:

- Problems with the current NEM tariffs;
- Successor tariff proposals to address the issues presented;
- A successor tariff transition incentive proposal;
- Further justifications for the updated NEM policy proposals; and
- Timelines for the implementation of these policy proposals.

II. BACKGROUND

NEM was first established in 1995 by Senate Bill (SB) 656 (Alquist). In 2013, Assembly Bill 327 (Perea 2013)[3] added Section 2827.1 to the Public Utilities Code. Public Utilities Code Section 2827.1 provides the requirements for a successor tariff. These requirements include that the tariff:

> (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

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[1] *Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles* (Scoping Memo), R.20-08-020 (November 19, 2020), p. 4.

[2] *Public Advocates Office's Proposal for A Successor to The Current Net Energy Metering Tariff (Proposal),* R.20-08-020 (March 15, 2021). Amended Party Proposed served on April 7, 2021.

[3] Perea, Stats. 2013, Ch. 611.

> 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.[4]

Public Utilities Code Section 2827.1 further requires that "[a]ny rules adopted by the [C]ommission 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."[5] The statute also directs that participants be provided electric service at just and reasonable rates.[6] Public Utilities Code Section 451 mandates that rates be just and reasonable for all customers, which includes nonparticipants.[7]

In its January 2016 decision (NEM 2.0 Decision),[8] the California Public Utilities Commission (Commission) created "NEM 2.0" and committed to reviewing the NEM 2.0 tariff in 2019 to consider "adjustments to the successor tariff that include an export compensation rate (ECR) for NEM successor tariff customers that takes into account locational and time-differentiated values."[9] To help prepare for the 2019 review of the successor tariff, the NEM 2.0 Decision concluded that the Commission is authorized to take steps that would contribute to the Commission's administration of the successor tariff and any programs that implement alternatives for growth of renewable distributed generation among residential customers in

[4] Public Utilities Code § 2827.1(b)(1)-(4).

[5] Public Utilities Code § 2827.1(b)(6).

[6] Public Utilities Code § 2827.1(b)(7).

[7] See Pub. Util. Code § 451: "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable."

[8] Decision (D.)16-01-044.

[9] D.16-01-044, p. 4.

disadvantaged communities.[10] In 2019, the Commission announced it would not review a potential successor until 2020.[11] On September 3, 2020, the Commission issued the instant Order Instituting Rulemaking, (R.) 20-08-020, to create a successor tariff.

On November 11, 2020, Assigned Commissioner Martha Guzman Aceves and ALJ Hymes released the Joint Scoping Memo in R.20-08-020, which sets forth the issues, the need for hearings, a schedule, the proceeding category, and other matters. On January 21, 2021, ALJ Hymes released Verdant Associates, LLC's (Verdant) *Net Energy Metering 2.0 Lookback Study* (Lookback Study), which examines the performance of the NEM 2.0 program and its impacts. On January 28, 2021, ALJ Hymes released the *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California* whitepaper (Whitepaper) by Energy and Environmental Economics, Inc (E3) and Verdant,[12] which offers policy options for a successor tariff. On February 17, 2021, the Commission issued D.21-02-007 (Principles Decision) which provides the guiding principles for the development of the successor tariff.[13] On March 15,

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[10] D.16-01-044, p. 122. Disadvantaged communities include communities scoring in the top 25% of census tracts according to CalEnviroscreen, including those scoring in the top 5% for pollution burden without an overall score. They may also include tribal lands, low-income households, and low-income census tracts. See https://www.cpuc.ca.gov/discom/.

[11] *Sixth Amended Scoping Memo and Ruling of Assigned Commissioner*, R.14-07-002 (June 28, 2019), p. 5.

[12] Energy and Environmental Economics, Inc, *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California* (Whitepaper), January 28, 2021.

[13] *Decision Adopting Guiding Principles for the Development of a Successor to the Current Net Energy Metering Tariff* (D.21-02-007), R.20-08-020 (February 17, 2021), pp. 45-46. The decision provides eight guiding principles for the proceeding:

- A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1;
- A successor to the net energy metering tariff should ensure equity among customers;
- A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services;
- 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;
- 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;
- A successor to the net energy metering tariff should be transparent and understandable

2021, parties submitted their policy proposals for the successor tariff, and then presented their proposals at a workshop on March 23-24, 2021.[14]

ALJ Hymes emailed parties on April 4, 2021, extending the deadline for opening testimony to June 18, 2021.[15] The email also explained the Commission would examine the cost-effectiveness of all party proposals.[16] On April 22, 2021, the Commission held a second workshop to discuss the cost-effectiveness tests, and it contracted E3 to prepare the study.[17] On May 28, 2021, E3 released the *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (Cost-effectiveness Study).[18]

III. AN IMPROVED SUCCESSOR TARIFF MUST PROMOTE FAIRNESS FOR All CUSTOMERS

The successor tariff is a pivotal opportunity to ensure fair electricity rates for all customers and support behind-the-meter (BTM) generation adoption that will facilitate reaching California's climate and equity goals as quickly as possible.[19] Adoption of electric vehicles (EVs), and replacement of gas appliances in homes and businesses (building electrification) are

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to all customers and should be uniform, to the extent possible, across all utilities;

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

[14] Scoping Memo, p. 4.

[15] Email from ALJ Kelly A. Hymes to R.20-08-020 Service List, "R.20-08-020 Email Ruling Noticing April 22, 2021 Workshop and Revising Procedural Schedule," April 4, 2021.

[16] Email from ALJ Kelly A. Hymes to R.20-08-020 Service List, April 4, 2021.

[17] Email from ALJ Kelly A. Hymes to R.20-08-020 Service List, April 4, 2021.

[18] E3, *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020* (Cost-effectiveness Study), May 28, 2021.

[19] Senate Bill (SB) 100, De León, Stats. 2018, Ch. 312: "it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045." §2(e)(1): "[s]upplying electricity to California end-use customers that is generated by eligible renewable energy resources is necessary to improve California's air quality and public health, particularly in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code, and the commission shall ensure rates are just and reasonable, and are not significantly affected by the procurement requirements of this article;" and Executive Order (EO) B-55-18 to Achieve Carbon Neutrality, September 10, 2018. This EO sets a statewide goal of carbon neutrality by 2045. The EO emphasizes that "all policies and programs undertaken to achieve carbon neutrality shall seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities."

key transformational elements required for California to achieve its climate goals. High electricity prices will make achieving California's critical climate goals more difficult.

The proposals contained in the body of this Testimony are rooted in the fact that California ratepayers currently pay too much toward incentives for BTM generation through NEM. The cost of current NEM incentives unfairly raise electricity rates for those customers without BTM generation. These nonparticipating customers are paying unreasonably high bills to subsidize the customers who can afford to install BTM generation. The excessive expenditure currently required by nonparticipating customers to support the installation of BTM generation for those who can is described as "the cost burden." The cost of NEM incentives on nonparticipants create financial hardships, especially for lower-income customers and customers in disadvantaged communities.

In opening comments on the Proposed Decision on NEM guiding principles, Cal Advocates recommended that the Commission not focus the definition of "sustainable growth" in a narrow manner.[20] Instead, Cal Advocates recommended that the Commission should interpret "sustainable growth" to mean "growth whereby all customers can sustain the cost of that growth."[21] A successor tariff should foster sustainable growth of customer-sited renewable BTM generation in a way that equitably shares the costs and benefits among all customers. To achieve this, Cal Advocates' proposal encourages NEM reform and describes a successor tariff with a structure that provides a strong financial incentive for NEM adoption, supports efficient electricity use, and promotes equity and affordability.

In Appendix C of this Testimony, we include a matrix of other parties offering policy proposals with these same goals.

The following section of this Testimony will demonstrate how these goals are aligned with statute and proceeding guiding principles.

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[20] Comments of the Public Advocates Office on the Proposed Decision Adopting Guiding Principles for the Development of the Successor to the Current Net Energy Metering Tariff, R.20-08-020 (January 25, 2021), pp. 2-3.

[21] Comments of the Public Advocates Office on the Proposed Decision Adopting Guiding Principles for the Development of the Successor to the Current Net Energy Metering Tariff, R.20-08-020 (January 25, 2021), pp. 2-3.

IV. CAL ADVOCATES' SUCCESSOR TARIFF PROPOSAL SUMMARY

Cal Advocates proposes a successor tariff that fairly values NEM participants' BTM systems' benefits to the grid, increases program equity, and supports electric service affordability for all customers. This proposal will reduce the cost burden on nonparticipating customers, help reach California's climate and equity goals as quickly as possible, and align with statute and the Commission's guiding principles.

1. Create A More Fair, Balanced Nem Successor Tariff

1. Compensating a NEM participant through net billing at the avoided cost for their exported energy, instead of at the retail rate, would maintain a participant's ability to offset their electricity usage with their installed BTM generation. This compensation method would also reasonably and fairly compensate the customer for the energy exported based upon the actual value of the energy.[22]

2. Establishing a Grid Benefits Charge (GBC)[23] would ensure NEM participants are paying their fair share for grid services, including distribution, transmission, and public program costs.

3. Providing incentives to encourage NEM 1.0 and 2.0 participants to transition to the successor tariff would help maximize grid benefits with paired storage. This transition also would minimize the unintended rate burdens from the current tariffs that conflict with state equity and climate goals.

2. Create a More Equitable, Affordable Successor Tariff

1. Exempting lower income customers[24] from the proposed Grid Benefits Charge would create a larger value proposition for BTM adoption for lower income customers.

2. An Equity Charge on residential NEM customers to fund A) up-front subsidies to equalize payback periods for low-income ratepayers and B) programs focused on increasing

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[22] En Banc Whitepaper (Utility Costs and Affordability of the Grid of the Future, Feb. 2021), pp. 3-6.

[23] Grid Benefits Charges (GBCs) are also known as Grid Access Charges.

[24] Specifically, Cal Advocates recommends exempting California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers.

adoption of BTM systems in disadvantaged communities (DACs) which would address inequities created by the current NEM tariffs.[25]

V. CAL ADVOCATES' SUCCESSOR TARIFF WILL REDUCE THE COST BURDEN

In total, these proposals would reduce the total annual cost burden of the successor tariff on all nonparticipating customers by $1.8 billion per year in 2030. In addition, Cal Advocates' proposed transition of NEM 1.0 and 2.0 customers to the successor tariff would reduce the net present value (NPV)[26] of the total remaining cost burden created by NEM 1.0 and 2.0 customers from a total of $41.1 billion to a range of $16.3 billion (lower estimate) to $24.5 billion (upper estimate), which is a total reduction of $16.6 billion to $25.1 billion, (40-60%) over all remaining years of their current 20-year transition period.[27]

Figure 1-1 below illustrates the annual cost burden reductions in 2030 if all of Cal Advocates' proposed successor tariff policies are adopted.

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[25] The funds from an Equity Charge could be used to help these customers overcome initial barriers to adoption.

[26] Net present value is the value in today's dollar of a future stream of payments accounting for the time value of money – that is, the ability to earn interest on money if it were not invested in the project and put to some other use.

[27] Cal Advocates uses real 2021 dollars, not nominal dollars. Cal Advocates has removed the effects of inflation to see the value of the cost burden in today's dollars. These estimates assume annual escalation of electric rates by 4%. Future nominal dollars are converted into 2021 dollars (real dollars) using the 10-year average inflation or increase in the Consumer Price Index for All Urban Consumers of 1.7%. U.S. Bureau of Labor Statistics, Consumer Price Index News Release, 1/21/2021, accessed 4/5/2021 at https://www.bls.gov/news.release/archives/cpi_01132021.htm.

Figure 1-1: Cal Advocates' Policy Proposal Reductions to Total Annual Cost Burden of the Successor Tariff in 2030 ($2021)

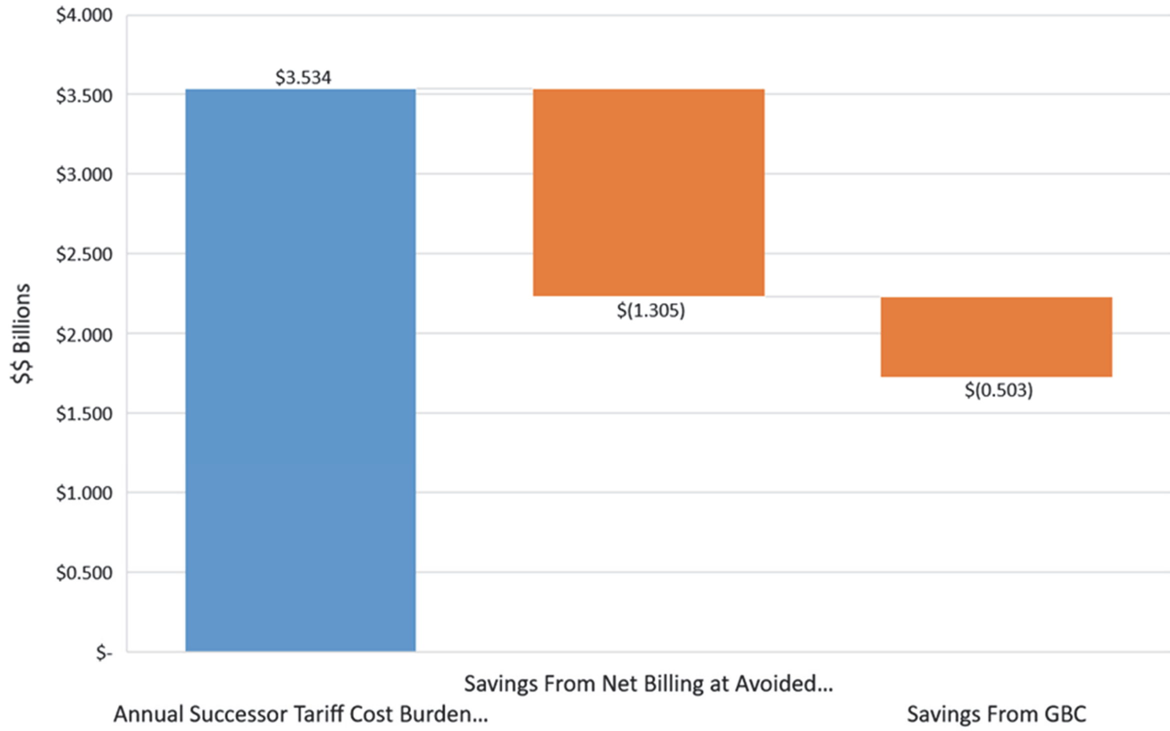
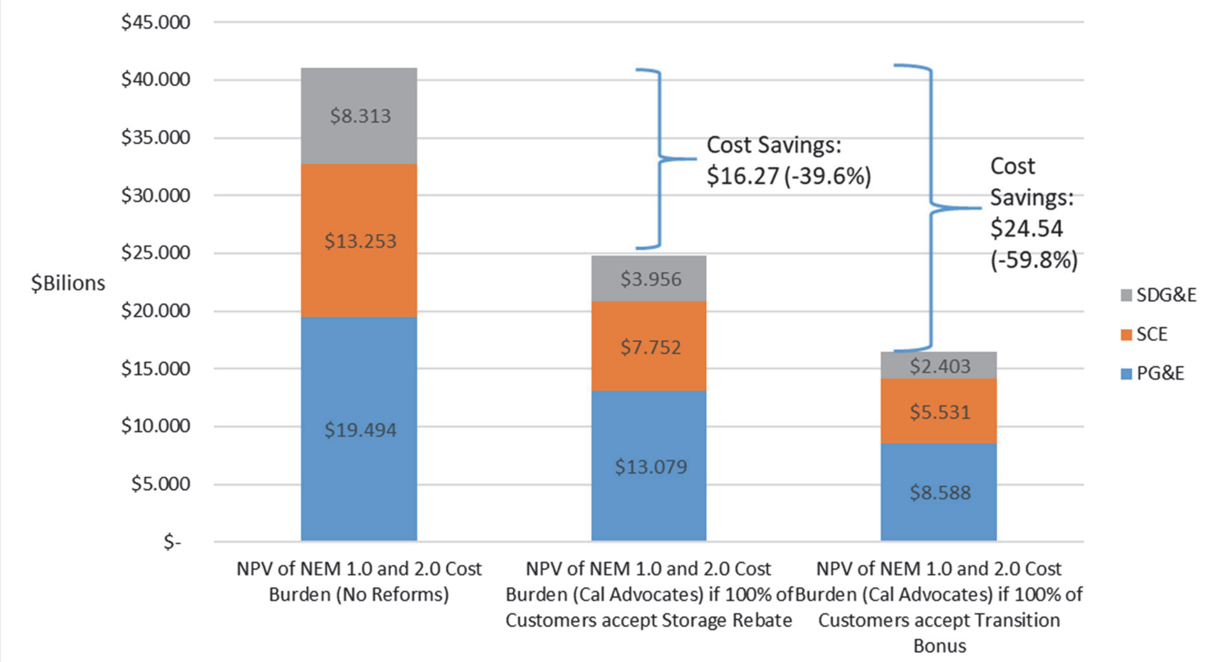


Figure 1-2 demonstrates the reduction to the total NPV of the NEM 1.0 and 2.0 cost burdens if Cal Advocates' NEM 1.0 and 2.0 transition incentive program is adopted. Figure 1-2 does not include any cost burden created by the successor tariff. It only includes the total cost burden created by the NEM 1.0 and NEM 2.0 tariffs over all remaining years of NEM customers' 20-year transition periods.

Figure 1.2 Reductions to Total NPV of NEM 1.0 and NEM 2.0 Cost Burdens under Cal Advocates' Proposal (2021 dollars)



Chapter 2 details how nonparticipating customers are paying heavily for those who can afford to participate in NEM. For example, the NEM subsidy comprises 19.6% of an San Diego Gas and Electric (SDG&E) residential customer's average bill.[28] In terms of bill savings, reforming NEM through these combined policies would save nonparticipating customers between $158 and $237 each year by 2030.[29]

The policy proposal contained in this Testimony would meaningfully reduce the cost burden and would continue to provide a strong incentive for installing rooftop solar and does not completely eliminate the cost burden. Cal Advocates' proposals would reduce the annual successor tariff cost burden by 51.2% and would reduce the NPV of the NEM 1.0 and 2.0 cost burdens by 39.6% to 59.8%. So approximately 49% of the successor tariff cost burden and 40% to 60% of the NEM 1.0 and 2.0 cost burdens would remain. This is because Cal Advocates'

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[28] Chapter 2 of this Testimony details how Cal Advocates uses the same method as Dr. Borenstein to determine the NEM subsidy impact on residential bills in each IOU territory. Dr. Severin Borenstein, Meredith Fowlie, and James Sallee. "Designing Electricity Rates for An Equitable Energy Transition," p. 28.

[29] Cal Advocates calculated the average subsidy of all NEM generation per customer by 2030 and then applied the % reduction to the cost burden that Cal Advocates' Proposal would produce to derive the % reduction in bills per customer.

successor tariff proposal balances reducing the cost burden with the other statutory requirements, such as encouraging distributed energy resources (DERs) to "grow sustainably"[30] and providing a "reasonable expected payback period."[31] The proposed tariff balances ensuring nonparticipants are not overburdened by the tariff's costs, supporting more DER adoptions in disadvantaged communities, and providing a fair value for DER adoption in California for all customers.

With these proposed reforms, residential customers on the successor tariff would still receive a meaningful subsidy; with monthly bill savings allowing for the systems to pay for themselves in 7.8-12.2 years.[32] These payback periods are generous considering solar panels still retain 80% of their starting efficiency after 40 years, so the system owner stands to accrue substantial long-term benefits.[33]

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[30] Public Utilities Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

[31] Public Utilities Code § 2827.1(b)(6): "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."

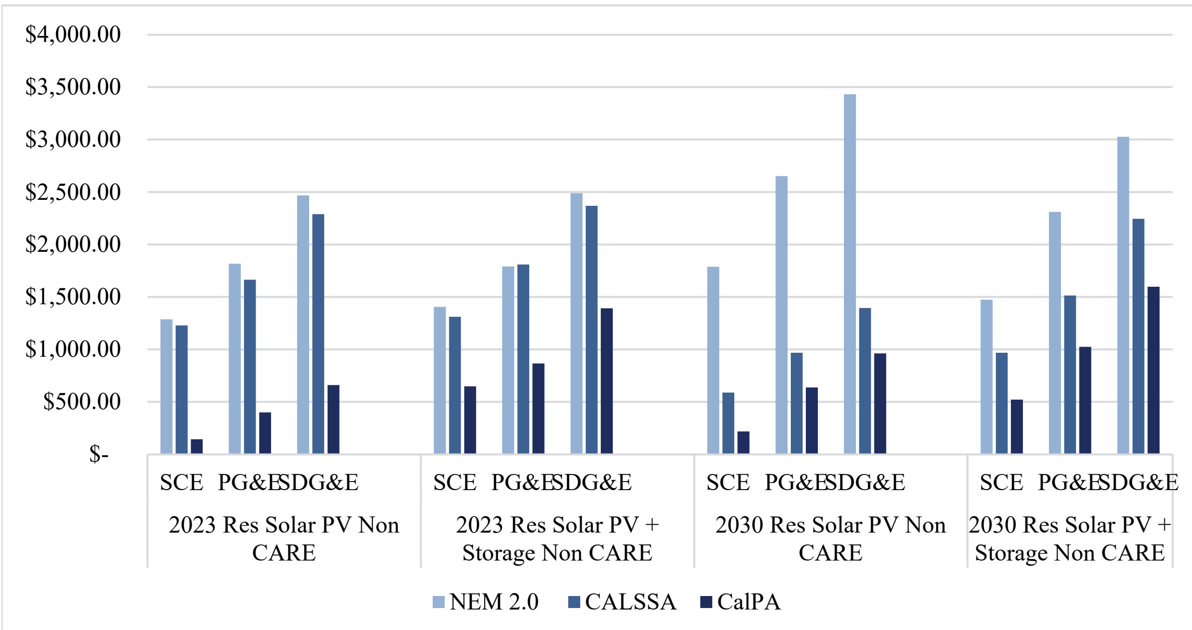
[32] Typical solar payback period with these reforms would range from 8.8-11.4 years for SCE, 8.8-12.2 years for PG&E, and 7.8-11.7 years for SDG&E. Using average 2021 PV system installation costs of $3.80/Watt from Lawrence Berkeley National Laboratory's 2019 Tracking the Sun report. See Section on Payback Periods in chapter 3 of this Testimony.

[33] Jordan, C. and Kurtz, S. *NREL Photovoltaic Degradation Rates- An Analytical Review*, p. 1. See: https://www.nrel.gov/docs/fy12osti/51664.pdf. This calculation is based on a median degradation rate of 0.50% per year.

Sunrun also provides a 0.50% degradation rate: "The median solar panel degradation rate is about 0.5%, which simply means that a solar panel's energy production will decrease at a rate of 0.5% per year. After 20 years, your panels should still be working at about 90% of its original output." See: Sunrun, "How Long Do Solar Panels Really Last?", https://www.sunrun.com/go-solar-center/solar-articles/how-long-do-solar-panels-really-last, accessed May 25, 2021.

Cal Advocates' successor tariff proposal also helps meet cost-effectiveness requirements for NEM 2.0 and NEM 1.0. Figure 1-3 below, populated with data from the Cost-effectiveness Study, shows the first-year cost burden of the Cal Advocates Proposal compared to NEM 2.0 and CALSSA.

Figure 1-3. E3's 2023 and 2030 Successor Tariff First-Year Cost Burden Results for Residential Non-CARE Customers.



VI. CAL ADVOCATES' SUCCESSOR TARFF ALIGNS WITH STATUTE AND GUIDING PRINCIPLES

As demonstrated in Cal Advocates' party proposal, the proposed successor tariff aligns with statute and the Commission's guiding principles.[34] The proposed successor tariff is based on the benefits of BTM renewable electrical generation,[35] participants are given just and reasonable rates,[36] and its benefits approximately equal the costs for all NEM participants and nonparticipants.[37] The successor tariff would also ensure the cost burden does not grow to a

[34] Proposal, pp 57-59.

[35] Public Utilities Code § 2827.1(b)(3).

[36] Public Utilities Code § 2827.1(b)(7).

[37] Public Utilities Code § 2827.1(b)(4).

point where rates are unreasonably high for nonparticipants,[38] which ensures BTM adoption can continue growing sustainably.[39] The successor tariff includes specific alternatives to grow BTM adoption for customers in disadvantaged communities[40] and ensure NEM 1.0 and 2.0 customers receive a reasonable payback period.[41]

Furthermore, the proposed successor tariff is aligned with the proceeding's guiding principles including "comply[ing] with the statutory requirements of Public Utilities Code Section 2827.1,"[42] "fairly consider[ing] all technologies,"[43] "ensur[ing] equity among customers,"[44] "maximiz[ing] the value of customer-sited renewable generation to all customers and to the electrical system,"[45] "be[ing] coordinated with the Commission and California's energy policies,"[46] and "be[ing] transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities."[47]

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[38] See Pub. Util. Code § 451.

[39] Public Utilities Code § 2827.1(b)(1).

[40] Public Utilities Code § 2827.1(b)(1).

[41] Public Utilities Code § 2827.1(b)(6).

[42] See D.21-02-007, p. 45 "(a) A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1."

[43] See D.21-02-007, p. 45 "(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."

[44] See D.21-02-007, p. 45 "(b) A successor to the net energy metering tariff should ensure equity among customers."

[45] See D.21-02-007, p. 46: "(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."

[46] See D.21-02-007, p. 46: "(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."

[47] See D.21-02-007, p. 46: "(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."

VII. CAL ADVOCATES' ANALYSIS AND PROPOSED SUCCESSOR TARIFF ADDRESSES THE ISSUES SCOPED IN THE PROCEEDING

Cal Advocates' analysis and proposed successor tariff addresses the issues presented in the Scoping Memo.[48] For Scoping Issue #2, this Testimony highlights results from the Lookback Study, showing lagging program adoption in disadvantaged communities (Chapter 2), NEM customers' underpayment relative to their cost of service (Chapter 2), and low numbers of NEM customer paired storage installations (Chapters 2 and 4). Chapters 3-4 of this Testimony contain policy proposals to address these problems.

For Scoping Issue #3, the preceding section explains how Cal Advocates' proposal complies with the guiding principles. Chapter 3 of this Testimony details the payback periods based on Cal Advocates' proposal, while Chapters 3-5 calculate its impact on the cost burden. Chapter 5 also details the cost-effectiveness scores for Cal Advocates' proposal compared to other party proposals.

This Testimony addresses Scoping Issue #4 by detailing Cal Advocates' proposed successor tariff in Chapters 3-4.

For Scoping Issue #5, Cal Advocates recommends the Commission adopt the proposed successor tariff as described in Chapters 3-4. Chapter 6 of this Testimony recommends a quick implementation period.

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[48] Scoping Memo, pp. 2-3. Section 2, Issues:

(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?

(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?

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

(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?

(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, the Renewable Energy Self-Generation Bill Credit Transfer program.

Note: ALJ Hymes' May 21, 2021 email "R.20-08-020 Procedural Email Providing Guidance on Party Testimony" stated "the issue of the net energy metering fuel cell tariff will be addressed separately in ruling and comments."

This Testimony addresses Scoping Issue #6 by detailing the growing cost burden created by NEM 1.0 and 2.0 customers (Chapter 2), and proposing a solution by incenting customers to transition to the successor tariff (Chapter 4). Chapter 2 details further issues with NEM including its impact on state equity and climate goals.

CHAPTER 2 THE CURRENT NEM TARIFFS ARE NOT EQUITABLE OR SUSTAINABLE

(Witnesses: Alec Ward, Ben Gutierrez, Nathan Chau, Adam Buchholz, Sophie Babka)

Current NEM design is not cost-effective, and it creates a large cost burden for nonparticipating customers which impacts the affordability of electricity. Because the current NEM structure directly ties rooftop solar compensation to retail rates, this burden will continue to grow unless the Commission updates its NEM policy. The current NEM structure drives up electrical rates, undermining important state climate goals including EV and building decarbonization efforts. NEM is also significantly more expensive than investments in other renewable energy technologies.

NEM adoption lags in disadvantaged communities, and it exacerbates racial energy cost disparities. Lastly, NEM does not maximize grid benefits as it primarily supports standalone rooftop solar where energy production does not align with current grid needs.

I. NEM 2.0 IS NOT COST-EFFECTIVE AND UNREASONABLY BURDENS NONPARTICIPANTS (A. Ward)

As currently designed, NEM is not a cost-effective program.[49] Cost-effectiveness is a fundamental principle that is essential for ensuring that ratepayers receive benefits that are at least as great as a program's costs. The Cost-effectiveness Study demonstrates that NEM 2.0 is significantly cost-ineffective, with a Ratepayer Impact Measure (RIM) test result of 0.11.[50] This means that ratepayers only receive $0.11 in benefits for each $1.00 in program costs. The Total Resource Cost (TRC) test omits important aspects of tariff impacts, including the payments made to participants and any cost burden on nonparticipants. Yet even with these omissions, the residential NEM 2.0 tariff still fails the TRC test with a score of 0.36.[51] This means ratepayers are spending billions of dollars on a program with costs that greatly outweigh the benefits.

This Chapter describes how NEM is creating a large, and growing cost burden. The NEM program's increased ratepayer cost burden threatens California's climate goals because it

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[49] Cost-effectiveness tests results under the Commission's Standard Practice Manual will be further examined in Section 4 of this Proposal.

[50] Cost-effectiveness Study, p. 4.

[51] Cost-effectiveness Study, p. 5.

drives up electrical rates, thereby undermining state climate goals that need to be achieved through increased EV adoption and building electrification efforts.[52]

A cost-ineffective NEM program which creates a large cost burden on nonparticipating customers contravenes statutory requirements as the program is not based on the benefits of renewable electrical generation.[53] Consequently, nonparticipants are not served at just and reasonable rates,[54] because the program benefits do not approximately equal the costs for all customers participants and nonparticipants.[55] Instead, NEM creates a subsidy for customers who can afford to install rooftop solar, or other BTM generation. This subsidy is not explicit but is built in to the NEM tariff and results in a cost burden that drives unreasonable increases to overall electricity rates.[56] This cost burden also discourages sustainable growth in BTM generation adoption, because without a policy shift, the cost burden due to BTM generation will exacerbate electric service equity and affordability issues to the point where continued incentives for adoption of vehicle and building electrification will be impossible without creating additional cost burdens on lower income customers.[57]

A cost-ineffective NEM tariff further conflicts with the proceeding's guiding principles to "ensure equity among customers"[58] and "maximize the value of customer-sited renewable generation to all customers and to the electrical system."[59] Therefore, the Commission should reject any successor tariff proposal that would extend the current NEM structure into the future.

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[52] Governor Brown Executive Order B-48-18. Office of Governor Edmund G. Brown, "Governor Brown Takes Action to Fund Zero-Emission Vehicles, Fund New Climate Investments," January 26 2018, accessed April 13 2021 at https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html

[53] Public Utilities Code § 2827.1(b)(3).

[54] Public Utilities Code § 2827.1(b)(7).

[55] Public Utilities Code § 2827.1(b)(4).

[56] Public Utilities Code § 451.

[57] Public Utilities Code § 2827.1(b)(1).

[58] See D. 21-02-007, p. 45: "(b) A successor to the net energy metering tariff should ensure equity among customers."

[59] See D. 21-02-007, p. 46: "(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."

A. NEM is Creating an Unreasonably Large and Growing Cost Burden (B. Gutierrez and N. Chau)

Under current NEM tariffs, customers can reduce their bill at the retail rate for every kilowatt hour (kWh) of electricity their BTM system generates.[60] Because residential rates primarily collect costs through volumetric (kWh) charges, NEM customers can avoid paying for the energy, capacity, and fixed costs that the utility primarily collects from residential customers through volumetric charges.[61] While the generation from these BTM systems helps to offset some utility costs, this benefit of utility cost reduction is much smaller than the total charges NEM customers can offset with their generation. The difference between the amount of retail volumetric charges NEM customers can avoid and the benefits that their generation provides to the overall system is the cost burden. The cost burden is paid by all ratepayers, NEM and Non-NEM alike, but since NEM customers make up a small proportion of total customers and are able to net out a significant portion of their annual usage, most of the cost burden created by the NEM tariffs falls on nonparticipating customers.

The annual cost burden generated by the NEM 1.0 and 2.0 tariffs will be approximately $3.37 billion in 2021.[62] Cal Advocates provides a breakout of the annual cost burden by NEM 1.0 and 2.0 of each of the three major investor-owned utilities (IOUs) in 2021 below:[63]

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[60] The only exception to this rule is that NEM 2.0 customers are not allowed to net their exports against consumption for purposes of calculating their non-bypassable charges, which include the Public Purpose Program (PPP) charge, Nuclear Decommissioning (ND) charge, Competition Transition Charge, and Department of Water Resources bond charges (DWRB-C). However, these four NBCs make up a small portion of residential retail rates, so average annual compensation for NEM 2.0 residential net exports ($/kWh) that are not subject to the annual true-up is typically 91 to 96% of full retail rates. D.16-01-044, p. 89. Cal Advocates' cost burden models for PG&E, SCE, and SDG&E, "Rates Input – nonGF" tabs.

[61] Customers of other classes that take service on rates that recover large amounts of costs through volumetric rates can also avoid paying large portions of these costs.

[62] Based on Cal Advocates' calculations, the workpapers for which made available to parties upon request.

[63] The calculations back out the effects of inflation using the average 10-year annual increase (2010-2020) in the Consumer Price Index for Urban Consumers of 1.7% per year.

Table 2-1
Comparison of 2021 Annual NEM 1.0 and 2.0 Cost Burdens by IOU ($ Millions)

	PG&E ($MM 2021)	SCE ($MM 2021)	SDG&E ($MM 2021)	Total ($MM 2021)
NEM 1.0	$747.21	449.67	$245.52	$1,442.41
NEM 2.0	$1,027.09	573.98	$328.84	$1,929.91
Total	**1,774.30**	**1,023.66**	**574.36**	**$3,372.32**

The total cost burden of the NEM 2.0 tariff for Pacific Gas and Electric (PG&E) alone is *$1.027 billion per year*. The combined total cost burdens of the NEM 1.0 and 2.0 tariffs are $1.774 billion per year for PG&E, $1.024 billion per year for Southern California Edison (SCE), and $574 million per year for SDG&E. These represent a recurring annual transfer of revenues from nonparticipants to existing NEM customers that is not supported by any avoided costs value provided to the system.[64] In total, the NEM 1.0 tariff creates $1.44 billion in cost burden annually or 43% of the total annual NEM 1.0 and 2.0 cost burden ($3.37 billion), while the NEM 2.0 tariff creates $1.93 billion in cost burden per year to general ratepayers or 57% of the total.

The current policy is unsustainable and if left unchanged, the total cost burden of the NEM 1.0, NEM 2.0, and successor tariffs (assuming no reform), that nonparticipants will pay for, will grow to $6.9 billion per year by 2030 in today's dollars ($ 2021).[65]

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[64] That is, the cost burden represents the total transfer of revenues that *exceeds* the total avoided costs value of PV generation to the system, so this direct transfer of revenues from general ratepayers to NEM customers it not substantiated by any underlying value to ratepayers.

[65] Cal Advocates cost burden workpapers are available to parties upon request.

Table 2-2
Comparison of Total NEM 1.0, NEM 2.0, and Successor Tariff Annual Cost Burden by IOU in 2030 with No Reforms ($ Millions)

	PG&E ($MM 2021)	SCE ($MM 2021)	SDG&E ($MM 2021)	Total ($MM 2021)
NEM 1.0	$662.97	429.74	$232.77	$1,325.47
NEM 2.0	$1,107.28	573.46	$364.74	$2,045.48
Successor Tariff[66]	$2,015.84	1,279.53	$238.69	$3,534.06
Total	**3,786.09**	**2,282.72**	**836.20**	**$6,905.01**

The figures in Table 2-2 represent the cost burden generated by all customer classes combined. Cal Advocates estimates the successor tariff annual cost burden assuming a continuation of the present NEM 2.0 tariff (no reforms). Similarly, the NEM 1.0 and 2.0 estimates show the expected levels of these cost burdens if there are no reforms to the NEM 1.0 and 2.0 tariffs. With no reforms to the tariffs, the total annual cost burdens created by the NEM 1.0, 2.0, and successor tariffs are expected to be $3.79 billion per year for PG&E customers, $2.28 billion per year for SCE customers, and $836 million per year for SDG&E customers by 2030. Cal Advocates provides an explanation of the calculations and assumptions underlying its cost burden estimates in Attachment A to this Testimony.

The rooftop solar market has grown to such an extent that the current tariff structure is expected to produce inordinately large, unsustainable, and growing cost burdens to ratepayers of the three largest IOUs over the next decade. In addition, these cost burdens would occur against a backdrop in which electricity rates continue to increase faster than the rate of inflation, which result in increases in electric bill costs as a proportion of total household expenditures and of

[66] This scenario assumes no changes from the existing NEM 2.0 tariff. The PG&E and SCE cost burdens also include the cost burden created by residential behind-the-meter (BTM) storage using PG&E and SCE's company forecasts of growth in residential BTM storage (2022-2030). Cal Advocates assumed that BTM storage is operated entirely for time-of-use (TOU) arbitrage and developed charging and discharging annual production weights by TOU period. Storage modeling is more fully described in Chapter 4 concerning Cal Advocates' NEM 1.0 and 2.0 transition proposal. The same modeling assumptions were used for the Successor Tariff as for NEM 1.0 and 2.0 customers newly adopting storage. Storage accounts for 6% of the PG&E and SCE cost burdens.

income for many ratepayers.[67] In sum, the combination of tariffs—NEM 1.0 and NEM 2.0, create unsustainable cost burdens that place unsustainable pressure on the affordability of rates at a time when customers already are experiencing an affordability crisis due to rapid increases in rates that are outpacing the inflation rate. The NEM tariffs are part of the cost drivers of the current rapid increases in electricity rates and require urgent reform.

The calculations used to determine the cost burden can be found in Attachment A.

1. The cost burden equals total customer bill savings minus total avoided costs

To estimate the total benefits that NEM customers' photovoltaic (PV) generation provides to the system, Cal Advocates uses the hourly avoided costs from the 2021 Avoided Costs Calculator (ACC) over the year weighted by an annual hourly PV production profile,[68] to yield a single annual PV-weighted average avoided costs value of solar PV ($/kWh) for each IOU.[69] Cal Advocates multiplies the average avoided costs of PV ($/kWh) by total annual PV generation (kWh) by customer class to yield the total avoided costs provided by NEM customers of each customer class. Finally, Cal Advocates subtracts the annual avoided costs associated with the total solar production attributed to each customer class from each customer class' annual bill savings to yield to the annual cost burden. The result is summed across all customer classes. An example is provided below for the NEM 2.0 tariff for the three major IOUs:

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[67] CPUC staff whitepaper entitled "Utility Costs and Affordability of the Grid of the Future" dated February 2022, p. 8. Commission staff forecasts electric rates to increase at an average rate of 3.5% per year over the next decade (2021-2030). As shown in Table 2A-1 of Attachment 2-A, this is a conservative estimate, because residential average rates of the three IOUs have increased at an average rate of 5-7% per year over the past 5 years. Thus, it is likely with no reforms to present policies, rates will increase at a rate faster than 3.5% over the next nine years. In contrast, the ten-year annual average increase in inflation (2010-2030) was 1.7%. U.S. Bureau of Labor Statistics, Consumer Price Index News Release, 1/21/2021, accessed 4/5/2021 at https://www.bls.gov/news.release/archives/cpi_01132021.htm.

[68] Cal Advocates uses a PV production profile from PVWatts for PG&E and SDG&E, although the PV profile for SCE is an aggregation of actual residential PV production data.

[69] Cal Advocates' annual average avoided costs calculations of PV include all avoided costs components from the 2021 ACC. For instance, the average annual avoided costs of PV in 2021 is $0.04773/kWh for PG&E, $0.05477/kWh for SCE, and $0.04530/kWh for SDG&E. Cal Advocates' workpapers "1. PGE_Cost_Burden_Model," "2. SCE_Cost_Burden_Model" and "3. SDGE_Cost_Burden_Model.xlsx" General_Inputs tab.

Table 2-3
Calculation of Total NEM 2.0 Cost Burden by IOU in 2021[70]

	PG&E ($MM 2021)	SCE ($MM 2021)	SDG&E ($MM 2021)
Total NEM Customer Bill Savings	$1,290.75	$779.82	$403.06
Total Avoided Costs	$263.66	$205.83	$74.22
Total Cost Burden	**$1,027.09**	**$573.98**	**$328.84**

Table 2-3 demonstrates the large difference between the total bill savings that NEM customers receive on the NEM 1.0 and 2.0 tariffs and the total benefits (avoided costs) their generation provides to all customers and to society. For instance, according to the results of the ACC, PG&E's NEM 2.0 customers' on-site generation provides $263.66 million per year in total avoided costs to all customers, yet ratepayers are required to pay NEM customers – which comprise only 10.4% of total residential customers[71] – *$1.29 billion* per year for their generation, which is 4.9 times the total benefits provided to the system. Similarly, in SCE's territory, ratepayers are paying 3.8 times the total benefits provided by its NEM customers, and in SDG&E's territory, SDG&E customers are paying 5.4 times the total avoided costs. As a result, the cost burden has now grown to billions of dollars per year and is a significant burden on customers' rates.

2. Implications of the NEM cost burden on equity

The current NEM policy of offering retail rate compensation for solar PV production has significantly increased retail electricity rates. For instance, researchers at the Energy Institute at Haas at the University of California Berkeley assessed the residential rate impacts of the NEM cost burden by estimating what residential rates would have been absent investments in residential solar PV.[72] Their analysis shows that the average PG&E, SCE, and SDG&E non-

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[70] Cal Advocates workpapers "1. PGE_Cost_Shift Model," "2. SCE_Cost_Shift_Model," "3. SDGE_Cost_Shift_Model" tab Cost Shift NEM 2.0.

[71] There were 510k NEM customers as of August 2020 per PGE response to DR CalAdvocates-PGE-03. At that time, this made up (0.510million/4.9 million) about 10.4 percent.

[72] Dr. Severin Borenstein, Meredith Fowlie, and James Sallee. "Designing Electricity Rates for An Equitable Energy Transition," p. 28. "For each utility-year, the electricity generated by installed

NEM non-California Alternate Rates for Energy (CARE) residential customer paid $152, $100, and $234 more in their annual bills, respectively, due to compensation of all NEM generation at retail rates in 2019. The average PG&E, SCE and SDG&E non-NEM CARE customer paid $106, $67, and $128 more on their annual bills in 2019, due to compensation of all NEM generation at retail rates, respectively.[73] Using the same method[74] Dr. Borenstein used to compute these figures, Cal Advocates was able to determine that the NEM subsidy comprises 12.3%, 9.7%, and 19.6% of PG&E's, SCE's and SDG&E's average residential bills, respectively. Customers who are larger users than average—for instance, customers who may have large families or who reside in inland areas and have higher cooling needs in summer—face significantly higher average annual bill impacts from the current NEM tariffs. If the Commission maintains the status quo, the annual cost burden will increase from $3.37 billion per year in 2021 to $6.9 billion per year by 2030, meaning the annual customer bill impacts referenced above will grow substantially.

The current NEM tariff produces inequitable outcomes in terms of customer costs. Because residential NEM customers are credited at retail[75] electricity rates for every kWh of solar electricity they generate, the burden of recovery of marginal costs[76] and fixed costs[77] in excess of avoided cost is shifted onto customers that have not adopted BTM generation under

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residential BTM PV was simulated and then this generation was added to the actual residential electricity sales. Next, an estimate of how much lower retail rates would have been had costs been spread across this broader base of residential electricity consumption was established."

[73] Dr. Severin Borenstein, Meredith Fowlie, and James Sallee. "Designing Electricity Rates for An Equitable Energy Transition," p. 28.

[74] For each utility-year, the electricity generated by installed residential BTM PV was simulated and then this generation was added to the actual residential electricity sales. Next, an estimate of how much lower retail rates would have been had costs been spread across this broader base of residential electricity consumption was established.

[75] With some exceptions being certain non-bypassable charges such as public purpose program charge, nuclear decommissioning charge, the department of water resources bond charge and the competition transition charge. Under NEM 2.0 tariffs, customers cannot offset such charges via exports but can offset them via generation they consume onsite.

[76] For instance, NEM 2.0 customers pay on average only 9-18% of their total cost of service, which is significantly below even the marginal costs to serve them. Verdant Associates, LLC, "Net Energy Metering 2.0 Lookback Study," 21 Jan 2021, p. 12.

[77] As opposed to recovery of marginal costs. Fixed costs are defined herein as the difference between total marginal costs revenues of the system and the total system costs (revenue requirement). For more information, see Section 3.III, explaining the need for a grid benefits charge (GBC).

NEM. As of the end of 2020, residential NEM customers comprise just 10.4%, 8%, and 15% of total residential customers in PG&E's, SCE's, and SDG&E's service territories, respectively. Yet this small group is the beneficiary of these billions in costs paid by all other customers.[78] Thus, the vast majority of non-NEM residential customers are forced to subsidize this subset of customers, who are mostly made up of homeowners and are often more affluent customers.[79]

B. The Current NEM Tariff Undermines State Decarbonization Goals Including Electric Vehicle Adoption and Building Electrification (B. Gutierrez and N. Chau)

The cost burden attributable to NEM is increasing average electric rates for customers, which jeopardizes the state's goal of achieving GHG reductions via beneficial electrification of transportation and buildings. High customer electric rates will discourage customers switching from gasoline- or natural gas-fueled technologies to electric technologies because doing so will become less economically beneficial.

The Legislature has found that widespread transportation electrification is needed to achieve the goals set forth in the Charge Ahead California Initiative and to reduce emissions of statewide GHGs "to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050."[80] As part of these goals, the state has set a target of 5 million zero emission vehicles on the road in California by 2030.[81]

To achieve the State's ambitious goals, the Commission needs to minimize increases in electric rates, as one of the main drivers for customer adoption of EVs and building electrification is the potential to realize fuel cost savings. The Legislature has found that widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a fuel.[82] Generally, for every dollar increase in the cost per gallon of

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[78] Will include table with number of NEM vs nonparticipants in each IOU.

[79] See Section II A-C of this testimony for further details on the current inequities in BTM solar adoption by income and by race.

[80] Public Utilities Code § 740.12(a)(1).

[81] Governor Brown Executive Order B-48-18. Office of Governor Edmund G. Brown, "Governor Brown Takes Action to Fund Zero-Emission Vehicles, Fund New Climate Investments," January 26 2018, accessed April 13 2021 at https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html

[82] D.20-08-045, p. 7. The Legislature also found that "[a]dvanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse

gasoline, the breakeven point in fueling costs is roughly equal to 10 cents per kWh of electricity.[83] Thus, when the cost per gallon of gasoline is $3, the cost of fueling an equivalent vehicle with electricity must be lower than 30 cents/kWh to break even in fueling costs.[84] In addition, a 2018 survey of diverse stakeholders in the commercial EV sector conducted by the Electric Power Research Institute found that the overall level of electric rates for fueling will be a key factor in commercial customers' EV adoption decisions over the next decade:

> "A common viewpoint was that when there is parity cost of vehicle, energy cost, and operating/maintenance cost, electric rates will be a key determinant of long-term EV viability."[85]

Finally, at the Commission's February 24, 2021 "En Banc on Energy Rates and Costs," David Rapson, Director of the Davis Energy Economic Program at the University of California, Davis, presented that "[e]ach $0.10/kWh increase in electricity prices" results in a "15% decrease in EV demand" (in terms of EV miles driven).[86] Rapidly escalating electricity prices therefore hinders the state's goal of achieving widespread EV adoption and EV miles driven.

Unfortunately, electric prices have been increasing faster than natural gas and gasoline prices.[87] In the last decade (between January 2010 and January 2020), the average price for a

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gas emissions reductions goals," and that widespread transportation electrification "requires electrical corporations to increase access to the use of electricity as a transportation fuel."

[83] EVGO Fleet and Tariff Analysis Phase 1: California," p. 1. "Utilities, their regulators, and EV charging station owners and operators must work together to provide all EV drivers—especially those without home and workplace charging options—access to reliable EV charging at a rate competitive with the gasoline equivalent cost of $0.29/kWh." This figure assumes 32 mpg, $3/gallon of gas, 0.32 kWh/mile as descried in footnote 2. Thus, for every dollar increase in the cost per gallon of gasoline, the breakeven point in fueling costs in terms of the cost per kWh of electricity.

[84] EVGO Fleet and Tariff Analysis Phase 1: California," p. 1. This heuristic does not account for differences in upfront costs and operating costs of purchasing internal combustion engine vehicles and EVs. EVs are often more expensive on an upfront basis than ICE vehicles. Therefore, it is important to maintain electrical fueling prices at levels that are consistently lower than gasoline prices to help drive EV adoption.

[85] A.20-10-011, Exh. PG&E Testimony on its Commercial Day Ahead Real-Time Pricing (DAHRTP) Pilot, p. 1-AttachmentA-29.

[86] Slide 36, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_PANEL%201_Updated.pdf.

[87] See: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_SCA_DPG&f=A

The average price per gallon of gasoline (all grades) in California was $3.66/gallon in January 2014 and gallon of gasoline in California increased by 14%. Over the same period, PG&E's, SCE's, and SDG&E's residential average rates increased by 41%,[88] 22%,[89] and 60%[90] respectively. If this trend continues, it will become increasingly challenging to attract customers to adopt EVs based on the economics of fueling the vehicle.

Though low electric rates are an important tool in encouraging EV adoption, simply discounting certain EV or electrification rates to get around high average electric rates can exacerbate the existing equity issues caused by NEM. Assuming that customers charge their EVs in a manner that is aligned with grid conditions,[91] additional EV load over the next decades presents the opportunity to place downward pressure on all customers' rates by allowing the utilities to spread their fixed costs across a larger sales (kWh) base.[92] However, many residential and commercial EV rates have large portions or all of the rates set at marginal costs in order to provide adequate opportunity for fuel cost savings vis-à-vis fossil fuels and promote EV adoption. When EV rates are set significantly below cost basis, there is less recovery of fixed costs, and when rates are set at marginal costs, there is no recovery of fixed costs[93] —meaning that there would be no resulting downward pressure on other customers' rates. It also means that other customers are subsidizing the participation of customers on these EV or electrification rates because the Commission approved revenue requirement, including those fixed costs, will still need to be recovered.

PG&E's Business Electric Vehicle rates for commercial customers have their distribution rates set at marginal costs and SDG&E's Electric Vehicle High Power (EV-HP) rates for

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$3.49/gallon in January 2020. This period coincides with the significant uptake in residential solar PV adoption and excludes any months during which the California's COVID-19 shelter in place order was in effect.

[88] AL 3518-E and AL 5661-E.

[89] 1-22-19_CPUC Affordability Workshop_Materials and AL 4116-E-A.

[90] AL 2135-E and AL 3487-E.

[91] Two examples of charging that is aligned with grid conditions are when customers manage their total maximum customer demand (kW) in order to avoid placing high stress on localized distribution infrastructure and when customers charge their EVs in accordance with TOU price signals.

[92] This can result in reductions in the average $ per kWh costs for all customers, assuming EV customers do not receive large, ongoing discounts in their rates from cost basis as is discussed further below.

[93] This is because rates that are set at marginal costs theoretically only recover the marginal costs to serve the customers' demand, but there is no recovery of costs beyond marginal costs (fixed costs).

medium-duty and heavy-duty vehicle and fast charging uses currently have both the generation and distribution rates set at marginal costs.[94] In addition, SDG&E's residential optional EV-TOU-5 (time-of-use) rate has super off-peak rates that are *less* than the marginal costs price floor because they contain zero distribution costs. SCE's residential optional TOU-D-PRIME rate includes artificial reductions to the winter Off-Peak rates that are below cost basis.[95]

The Commission has deemed it necessary to discount EV rates at below full cost basis in order to promote EV adoption and provide sufficient opportunity for fuel cost savings in the initial years while charger utilization rates are low.[96] However, it is not clear when it will be possible in future years to bring EV rates closer to cost basis and provide the expected benefits of EV load to all ratepayers if electric rates continue to grow at their unsustainable pace. The NEM cost burden also impacts when EV rates can be brought in alignment with cost basis, because the NEM cost burden is a major causative factor in the current unsustainable increase of residential electric rates. If left unchecked, the NEM cost burden may create the need for large ongoing discounts to EV rates, creating another form of inequitable cost burdens, and preventing ratepayers from experiencing the benefits of rate stabilization that EV load can provide.[97]

Rising electricity rates also make the value proposition of fuel switching or electrifying household end-uses less attractive to customers. A 5% incremental increase in electricity rates

[94] D.20-012-023 sets EV-HP distribution and generation rates at marginal costs for three years followed by a gradual phase-in of fixed costs over a seven-year period. However, the Decision also includes a requirement for a public workshop within 14 months of implementation of the rate to consider "course corrections" to the rate, including impacts on other ratepayers, EV-HP customer bills and fuel cost savings based on actual use cases, and possible adjustments to the rates. The rate design could change considerably based on EV-HP customer needs, observed charger utilization rates and average $ per kWh charging costs, so it is not clear if the phase-in of fixed costs will occur after 3 years as planned. D.21-12-023 pp. 24-25, 27.

[95] In the TOU-D-PRIME rate, the revenues that are lost from the off-peak rates are shifted to the Mid-Peak periods (summer 4-9pm on weekends and winter 4-9pm all days). However, as EV load grows EV owners will continue to avoid paying cost basis and these revenues may not be collected. A.17-06-030, Motion of SCE and Settling Parties for Adoption of Residential and Small Commercial Rate Design Settlement Agreement, Attachment A-15.

[96] See D.20-12-023 discussing the need to provide a declining rate discount over 10 years in the SDG&E's Electric Vehicle Higher Power (EV-HP) charging rate. The Decision also discusses the need to set EV-HP rates at marginal costs for the first 3 years in order to provide an adequate opportunity for fuel cost savings vis-à-vis conventional fuels and to account for low charger utilization due to the COVID-19 pandemic. D.20-12-023, pp. 13-14.

[97] In this case, the cost burden would be that EV customers would avoid paying their fixed costs responsibility-which would be paid for by other customers-and ratepayers would not experience the benefits of downward pressure from additional EV load.

increases the payback period of an electric heat pump water heater by about 4 years, making it more difficult for customers to achieve overall cost savings by electrifying their water heating. As a result,, fewer customers would be likely to make the large up-front capital outlays that are necessary to purchase and install heat pump hot water heater technology.[98] Reforming the NEM tariffs offers a significant opportunity to lower nonparticipants' average electricity rates and move rates closer to the actual costs to serve NEM customers, which would result in more economically efficient (and accurate) electricity pricing and improve the economic case for fuel switching without requiring ongoing distortions to cost basis in rates. Reducing the existing subsidies to NEM customers is the best solution to improve equity, economic efficiency, and create benefits to all ratepayers while ensuring EV adoption and electrification are properly incentivized.

C. NEM is Less Cost-Effective Than Other Renewable Energy Procurement Strategies (S. Babka)

The cost burden of generating renewable energy through the current NEM tariff is much higher than the cost of Renewable Portfolio Standard (RPS) renewable energy procurement contract prices. This means that customer dollars collected from non-NEM participants to pay for the cost burden induced by the current high retail rate compensation structure of NEM 1.0 and 2.0 could be avoided through policies and investments in more cost-effective ways to procure renewable electricity and achieve the states' climate goals.[99]

As utility rates continue to climb, and RPS contract costs decline, the excess cost burden required to pay for NEM generation continues to grow. Pursuant to Public Utilities Code 913.3(a)(1)-(2) and (b), annually the Commission releases data on the costs of renewable energy resources that are utility owned or under power purchase agreements.[100] From 2018 to 2019, the average price of an executed RPS contract dropped from \$0.0381 to \$0.0282 per kWh,[101] approximately a 26% decrease.[102] From 2019 to 2020 the average cost of an RPS contract

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[98] See Chapter 5 "Cal Advocates' Proposed Successor Tariff Would Help Achieve State Building Decarbonization Goals" of this Testimony.

[99] RPS contracts renewable energy resource contracts' eligibility is defined by Section 399.12(a).

[100] Public Utilities Code 913.3(a)(1)-(2) and (b).

[101] Adjusted into 2021 dollars this value would be roughly \$0.0287/kWh.

[102] 2020 Padilla Report (costs and costs savings for the RPS Program), published May 2020, (Padilla

increased to $0.035 per kWh hour due to "more diversified procurement of renewable generation from technologies such as bioenergy, geothermal, small hydro, and wind, and are higher in price compared to solar PV."[103]

In comparison, in November 2020, the average residential retail electricity rate for California was $0.2226 per kWh, a 10.7% increase from November 2019 when it was $0.2011 per kWh.[104] The Commission forecasts that the average residential retail rates of energy, and thus the price paid for NEM 2.0 excess generation, is set to continue to increase at a rate of about 4% per year.[105,106]

Renewable electricity purchased through an RPS contract is significantly less expensive than the cost burden imposed by the NEM structure for compensating BTM generation. Figures 2-1 and 2-2 below shows the average NEM cost *burden* per utility compared to the state's average *cost* of executed RPS contracts.

Report) pp. 2,10-11. See: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2020%20Padilla%20Report.pdf?__ac_lkid=2a14-b0f6-39ef-d2f417268072d07. These values are for contracts above 3MW. From 2007 to 2019 the average cost of a contract for all technologies decreased 12.7%, with wind and solar technologies together accounting for 87.4% of IOU's collective RPS generating technology.

[103] 2021 Padilla Report Costs and Cost Savings for the RPS Program (PU Code 913.3), published May 2021.

[104] EIA, Average Price of Electricity to Ultimate Customers by End Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a, accessed on February 7, 2021.

[105] D.20-08-001 Decision Adopting Standardized Inputs and Assumptions for Calculating Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems, p. 17.

[106] EIA, Average Price of Electricity to Ultimate Customers by End Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a, accessed on May 21, 2021. From February 2020 to February 2021 the residential rates in California increased from 21.70 cents/kWh to 22.53 cents/kWh, a roughly 4% increase.

Figure 2-1: 2019 NEM Cost Burden Comparison to RPS Executed Contracts

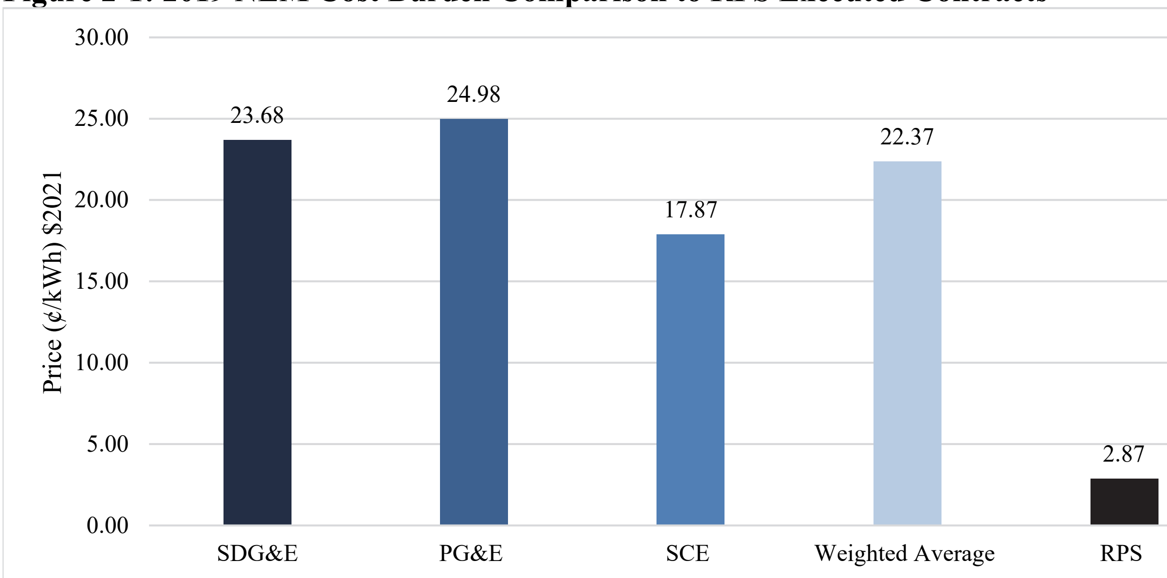
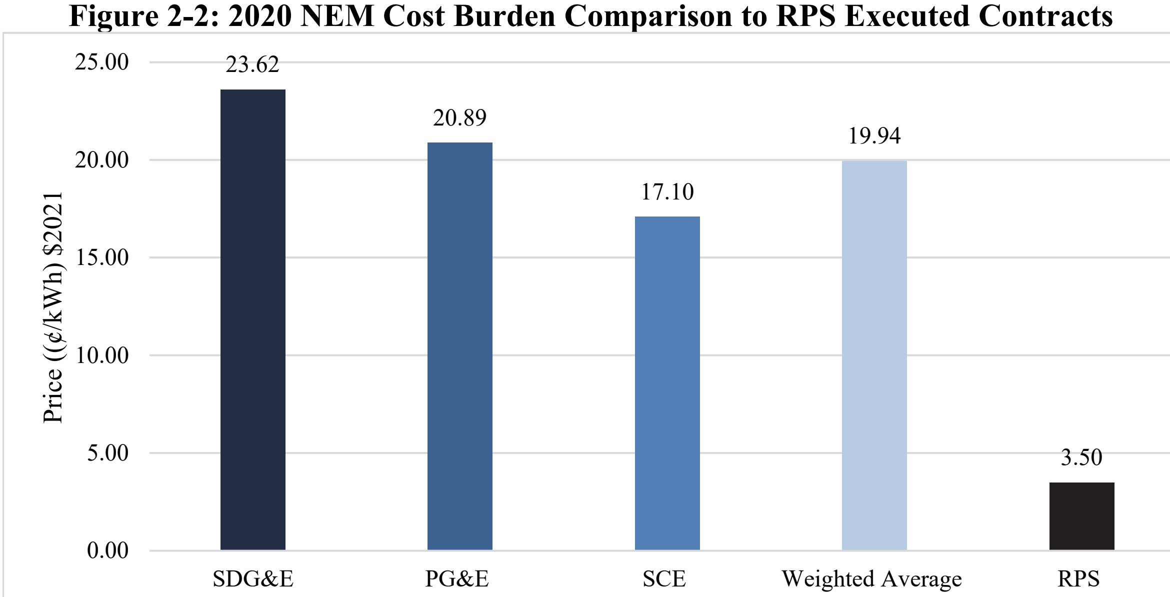


Figure 2-2: 2020 NEM Cost Burden Comparison to RPS Executed Contracts



Comparing the last two years' RPS contract costs with the annual cost burden from existing NEM customers demonstrates that NEM is not the most cost-efficient way to procure renewable energy. Overall, the weighted statewide average cost burden caused by NEM 1.0 and 2.0 total renewable generation combined is 7.80 times higher than RPS contracts for renewable generation in 2019.[107] Overall, the weighted statewide average cost burden alone caused by NEM 1.0 and 2.0 total renewable generation combined is 5.70 times higher than RPS cost of contracts for renewable generation in 2020.[108] The 2020 increase in the cost of RPS contracts due to non-solar PV renewables is the cause of the small decrease in magnitude from 2019 to 2020. Through its RPS contracting the Commission and IOUs are working on cost effective planned procurement of diversified renewable energy generation to better meet the grids needs. Non-dispatchable NEM policy essentially prioritizes incentives for rooftop solar PV at the expense of nonparticipants. The current NEM tariff is therefore an unnecessarily costly mechanism to reaching the state's renewable electricity procurement and climate goals compared to available alternatives such as RPS contracted renewable energy. The Commission should take into consideration the variety of costs required to achieve state renewable electricity procurement goals and feel comfortable with the more cost-effective options and modernize the successor NEM tariff.

II. NEM ADOPTION LAGS IN DISADVANTAGED COMMUNITIES

A. Low Income Customers Are Underrepresented Under NEM Tariff Structures (A. Buchholz)

The current NEM program is inconsistent with statutory requirements because the tariff does not include specific alternatives designed to increase BTM generation adoption rates for customers in disadvantaged communities (DACs).[109] NEM 1.0 and 2.0 have not proportionally benefited low-income customers, communities of color, or DAC residents.[110,111,112] Therefore, the Commission should reject any successor tariff proposal that continues the current NEM

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107 The investor-owned utilities' (IOU's) cost burdens are 4.48, 8.31, and 7.33 times higher than the cost of a 2019 RPS contract for SCE, SDG&E, and PG&E, respectively.

108 The IOU's cost burdens are 3.54, 6.75, and 6.03, times higher than the cost of a 2020 RPS contract for SCE, SDG&E, and PG&E, respectively.

109 Public Utilities Code § 2827.1(b)(1).

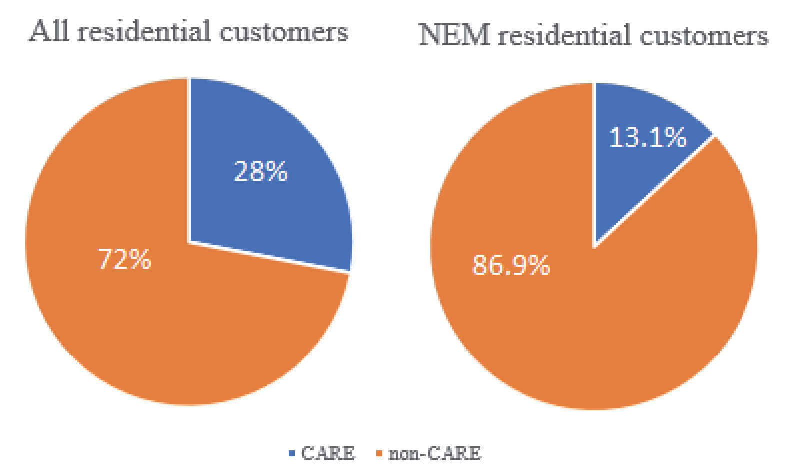
110 Lookback Study, p. 22, and Sunter, D., Castellanos, S., and Kammen, D. (2019). Disparities in Rooftop Photovoltaics Deployment in the United States by Race and Ethnicity. *Nature*, 2, pp. 71-76.

111 These categories overlap in many cases: CalEnviroScreen-designated DACs have significantly higher populations of low-income customers and people of color than non-DACs. CalEnviroScreen 3.0 Manual. See: https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf. "Analysis of Race/Ethnicity, Age, and CalEnviroScreen 3.0 Scores," California Office of Environmental Health Hazard Assessment 2018, p. 3.

112 Borenstein, Severin. "Rooftop Solar Inequity," Energy Institute Blog, UC Berkeley, June 1 2021.

structure for any period of time as being out of alignment with statute[113] and the Commission's Guiding Principles Decision. Low-income customers who participate in CARE currently have less access to NEM.[114] Out of all residential customers, CARE[115] customers represent 28% of total residential customers but only 13.1%[116] of NEM program participants,[117] meaning lower income customers are significantly underrepresented in NEM (see figure 2-3). There are several reasons for this disparity, including that low-income Californians are less likely to own their homes.[118]

Figure 2-3. CARE customers are significantly under-represented among NEM customers.



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[113] Public Utilities Code Section 451 mandates that rates be just and reasonable for all customers, which includes nonparticipants. Public Utilities Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators…include specific alternatives designed for growth among residential customers in disadvantaged communities."

[114] The SB350 Barriers Study cites a variety of barriers to DAC adoption including low homeownership rates, less access to credit, complex homeownership arrangements, remoteness, and others. Barriers Study p. 2.

[115] CARE customers have annual incomes up to twice the federal poverty level and receive a 30-35% discount on their energy bills. FERA customers have incomes at 250% of the federal poverty level and receive an 18% discount on their energy bill. See: https://www.cpuc.ca.gov/lowincomerates/.

[116] Cal Advocates data requests IOUs: PGE-3, SDGE-3, SCE-3. See Exhibit 2-B of this Testimony.

[117] Annual reports filed by PG&E, SCE, and SDG&E on the Energy Savings Assistance and California Alternative Rates for Energy Programs. PG&E: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/PGE-2020-PY2019-ESA-CARE-Annual-Report.pdf, SCE: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/SCE-2020-PY2019-ESA-CARE-Annual-Report.pdf, SDG&E: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/SDGE-2020-PY2019-ESA-CARE-Annual-Report.pdf .

[118] Senate Bill 350 Barriers Study, p. 2.

Currently, the few lower income customers with solar receive less value than non-CARE customers for the energy they produce, because net-metered credits are valued at their discounted retail electricity rate.[119] NEM CARE customers are also much less likely than wealthier customers to own their solar panels (see section II.B, below).

Most importantly, CARE customers without BTM generation are harmed by the NEM program cost burden. In 2019, the average PG&E, SCE and SDG&E non-NEM CARE customer annually paid $106, $67, and $128 more on their electric bills, respectively, due to NEM, meaning that nonparticipating CARE customers paid a significant portion of their electricity bill to support the unpaid costs of participating NEM customers.[120] To put this into perspective, the overall annual NEM cost burden ($3.37 billion) is more than double the total funding that the CARE program provides as bill discounts to low income CARE program participants each year ($1.3 billion).[121] As a result, ratepayers are paying almost twice as much in rates to fund the NEM program -- an incentive program that predominantly benefits more affluent customers -- than they are paying to fund a low-income assistance program.

DAC residents, many of whom are CARE customers, also have less access to BTM generation. The Lookback Study found that only 11% of NEM customers live in DACs, while DAC residents constitute 25% of the state's population.[122] In addition, this 11% DAC adoption rate is likely to be an overestimate because the Lookback Study aggregated data from census tracts to zip codes in a way that tends to overstate DAC adoption rates.[123] Given that lower

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[119] California Code, Public Utilities Code - PUC § 739.1 establishes a 30-35% discount on energy rates for low-income customers.

[120] Severin Borenstein, Meredith Fowlie, and James Sallee. "Designing Electricity Rates for An Equitable Energy Transition," p. 28.

[121] From IOU ESA CARE Annual Reports:

- PG&E: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/PGE-2020-PY2019-ESA-CARE-Annual-Report.pdf.
- SDG&E: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/SDGE-2020-PY2019-ESA-CARE-Annual-Report.pdf.
- SCE: https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2020/12/SCE-2020-PY2019-ESA-CARE-Annual-Report.pdf.

[122] Lookback Study, p. 22.

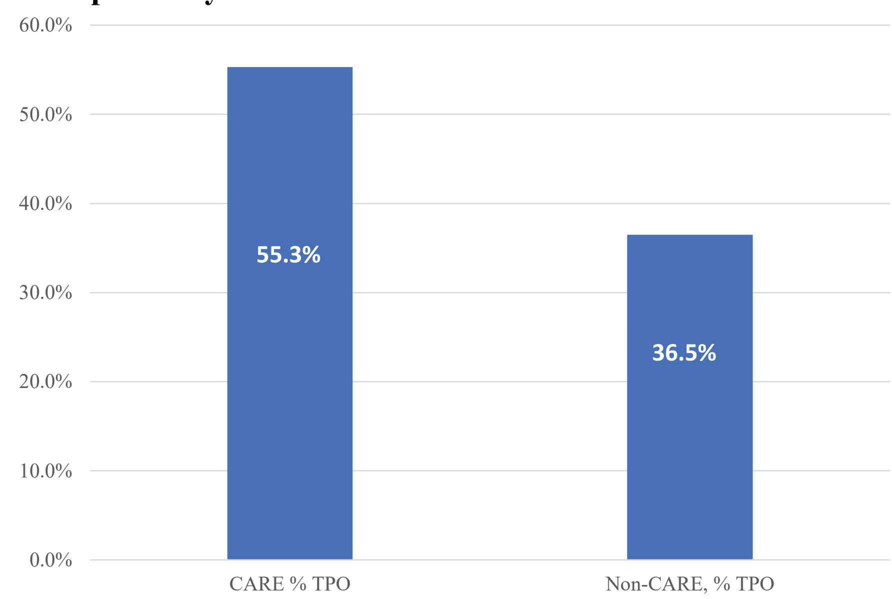
[123] *Comments of the Public Advocates Office on the Net Energy Metering 2.0 Lookback Study*, p. 4.

income populations are part of the definition of DACs,[124] DACs are likely to be disproportionately populated by CARE customers suffering the same exclusion, lower compensation due to discounted rates, low rate of ownership, and unfair cost burdens discussed above. Any successor tariff must address and reduce this inequity directly.

B. CARE Customers are Far Less Likely to Own Their Solar Panels, and More Likely to Pay Higher Prices for Them (A. Buchholz)

An analysis of IOU interconnection data reveals that NEM customers on CARE are 30% less likely than non-CARE NEM customers to own their rooftop solar systems. 55.3% of systems interconnected by CARE customers since 2015 were installed as part of a third-party ownership (TPO) arrangement such as a power purchase agreement (PPA) or a lease. Only 36.5% of non-CARE customers use these arrangements: CARE customers are 65% more likely to participate in third-party ownership models (see Figure 2-4).[125]

Figure 2-4. CARE customers are far less likely to own their rooftop solar systems.



This imbalance is problematic because third-party ownership arrangements provide significantly lower benefits to the customer than ownership. The solar parties' own data

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[124] CalEnviroScreen 3.0 Manual, https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf.

[125] Cal Advocates Data Request 10 to the IOUs.

demonstrates that CARE customers using a rooftop solar PPA can save as little as *$48, or 2%, per year on their bills*.[126] Figure 2-5 demonstrates the reduced value that third-party ownership arrangements provide according to the California Storage and Solar Alliance (CALSSA).[127]

Figure 2-5. Third-party ownership reduces benefits by at least 50%.

Solar panel ownership through a cash purchase, on the other hand, provides benefits that are 50% higher than third-party ownership models.[128] CARE customers' high rate of participation in PPA and lease arrangements means they receive much lower benefits than non-CARE customers who own their systems.

Additionally, while the costs associated with financing a system may reduce NEM program benefits relative to a PPA or lease, third-party ownership arrangements do not deliver other benefits associated with solar panel ownership such as increased property values. Therefore, third-party ownership arrangements should not be prioritized as a means of equalizing access to NEM for CARE and DAC customers.

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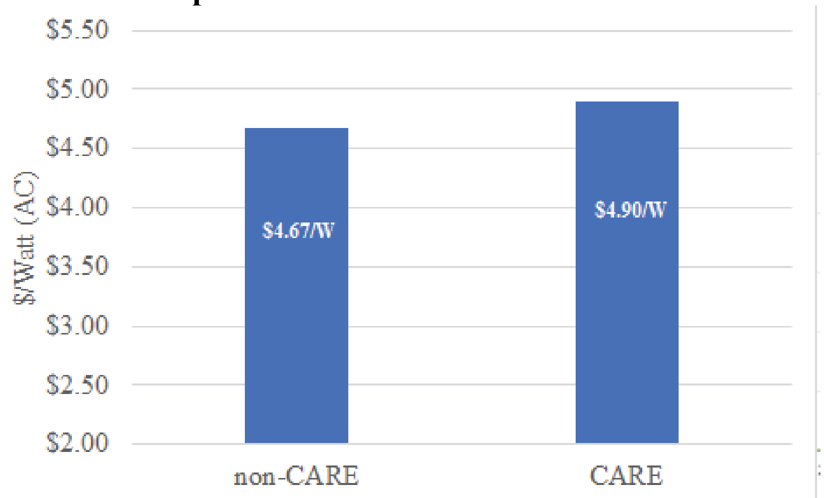
[126] Joint Parties NEM Equity Proposal by GRID Alternatives, Vote Solar, and Sierra Club, Appendix A: Savings after solar for an SCE CARE customer.

[127] CALSSA response to Cal Advocates Data Request 01.

[128] See Figure 2-5. CALSSA response to Cal Advocates Data Request 01.

Data from interconnection applications indicates that low-income ratepayers also pay significantly more than wealthier ratepayers when purchasing a system: CARE system owners paid 5% more than non-CARE customers from 2015-2020 (see Figure 2-6), further eroding the benefits to low-income customers from purchasing rooftop solar panels.[129]

Figure 2-6. CARE NEM customers paid 5% more to purchase solar panels from 2015-2020.



The current NEM tariffs perpetuates unequal costs and benefits for certain Californians, and any successor tariff proposal that continues the current inequitable NEM structure into the future should be rejected by the Commission. Based on the evidence provided and considering the dramatically lower customer savings from third-party ownership models, any claim that leases or PPAs are an equitable way of increasing access to the benefits of renewable energy should be treated with skepticism.

C. NEM Disproportionally Benefits White Households (A. Buchholz)

NEM disproportionately benefits higher income households. This disparity can directly impact the distribution of NEM benefits by race, since white households earn about 30% more than Black households and 40% more than Hispanic households in California.[130] On top of that,

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[129] Cal Advocates Data Request 10 to the IOUs.

[130] American Community Survey 5-Year Estimates – Public Use Microdata Sample (2019) (data.census.gov)

non-white households face unique challenges that could lead to differential benefits of NEM even within income groups. For example, Black households have less wealth and are less likely to be homeowners,[131] are more likely to face high-cost loans even when controlling for credit score and other risk factors,[132] and pay higher property taxes for the same home values.[133] All of these factors are likely to lead to reduced adoption of rooftop solar among non-white households. Indeed, a 2019 study of households across the US found that even after controlling for household income and home ownership, Black- and Hispanic- majority census tracts have installed 60% and 45% less rooftop PV compared with no majority tracts, and white-majority census tracts have installed 37% more.[134]

Therefore, the current NEM tariffs perpetuates unequal costs and benefits for certain Californians, and any successor tariff proposal that continues the current NEM structure into the future should be rejected by the Commission.

D. Urgent Reform is Necessary to Reduce the Cost Burden on Disadvantaged Communities and Rectify These Inequities (A. Buchholz)

The Commission must act to redress the inequities caused by NEM. CARE customers without rooftop solar pay significant and growing costs due to pressure on rates caused by the current NEM program. CARE customers and people of color have far lower access to rooftop solar than wealthier households, and low-income households are far less likely to own their panels and thus receive reduced NEM benefits.[135] Additionally, when CARE customers can afford to purchase solar panels, they pay significantly more for them.[136] The Commission should ensure that the successor tariff include specific means of correcting these inequities.

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[131] Rothstein, R. (2017). *The Color of Law: A Forgotten History of How Our Government Segregated America.* New York; London: Liverwright Publishing Corporation.

[132] Bayer, P. Ferreira, F., and Ross, S. (2018). What Drives Racial and Ethnic Differences in High-Cost Mortgages? The Role of High-risk Lenders. *The Review of Financial Studies,* **31** (1), 175-205.

[133] Avenancio-Leon, C. and Howard, T. (2019). The Assessment Gap: Racial Inequalities in Property Taxation. *SSRN Working Paper*

[134] Sunter, D., Castellanos, S., and Kammen, D. (2019). Disparities in Rooftop Photovoltaics Deployment in the United States by Race and Ethnicity. *Nature*, **2**, 71-76.

[135] See Section 2.II.B.

[136] See Section 2.II.B.

III. NEM DOES NOT MAXIMIZE GRID VALUE (A. Ward)

NEM currently conflicts with the proceeding's guiding principle that NEM should maximize value to all customers and the electrical system.[137] NEM predominately incentivizes standalone rooftop solar.[138] The Whitepaper notes that standalone solar fails to maximize grid benefits because the hours it produces energy "do not coincide with the hours when customer demand on the electric system as a whole is peaking."[139]

Energy is less valuable during the middle of the day, when rooftop solar primarily generates electricity, because electricity is abundant. In fact, with the increasing number of solar installations, there is an overabundance of electricity in the middle of the day. The California Independent System Operator (CAISO) has stated that due to the "increasing amounts of renewable resources, oversupply conditions are expected to occur more often," meaning that CAISO will have to curtail excess solar energy more often.[140]

The Whitepaper states "[w]hile the majority of the solar photovoltaic (PV) generation takes place during the middle of the day, the higher marginal cost value falls between hours ending 16 through 21" when "solar generation declines rapidly and therefore does not provide meaningful capacity value."[141] As solar resources decrease in the evening when electricity demands increase, standalone solar is unable to serve later hours of peak demand when natural gas peaker plants are used.[142]

Chapter 4 of this Testimony discusses the various ways paired storage can mitigate this issue. Unfortunately, the Lookback Study demonstrates that few NEM participants are pairing their systems with energy storage. Only 6% of NEM systems interconnected in 2019 were

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[137] See D.21-02-007, p. 46: "(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."

[138] "More than 90% of all megawatts (MW) of customer-sited solar capacity interconnected to the grid in the three large investor-owned (IOU) territories (PG&E, SCE, and SDG&E) in California are on NEM tariffs." See: https://www.cpuc.ca.gov/NEM/.

[139] Whitepaper p. 11.

[140] See the growing annual rates of energy curtailment by CAISO: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[141] Whitepaper p. 11.

[142] "The Private and Public Economics of Renewable Electricity Generation." Severin Borenstein, *Journal of Economic Perspectives,* 2012, p. 72.

paired with energy storage,[143] which indicates that the current NEM policies do not sufficiently encourage customers to pair their rooftop solar systems with storage.

The Commission needs to make bold policy reforms, as recommended in Chapter 4 of this Testimony, to address the issues presented in this section.

LIST OF ATTACHMENTS FOR CHAPTER 2

#	Attachment	Description
1	2-A	Description of Cal Advocates' Methods and Assumptions Underlying its Cost Burden Calculations
2	2-B	Cal Advocates' Data Requests for CARE and NEM Enrollment

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

CHAPTER 2

ATTACHMENT A – Supporting Materials

ATTACHMENT 2-A. Description of Cal Advocates' Methods and Assumptions Underlying its Cost Burden Calculations

I. Calculation of the Cost Burden

The total cost burden is equal to the difference between the total amount that NEM customers are compensated for their solar PV generation (total customer bill savings) and the total benefits their generation provides to the system and to all customers (total avoided costs).[144] In other words, total customer bill savings in excess of total benefits provided to the system are a cost burden, because they require a transfer of revenue from nonparticipants to NEM customers – that is, other customers are required to pay NEM customers for their generation that is not supported by any value provided to the system.

To forecast the annual cost burden, Cal Advocates obtained solar photovoltaic (PV) kW capacity forecasts from the each of the IOUs using NEM participation (kW) by rate schedule in 2020 multiplied by the California Energy Commission's 2020 California Energy Demand Update (CEDU) forecast of growth in distributed residential and non-residential solar PV.[145] The forecasted kW capacity values are broken out between NEM 1.0, NEM 2.0, and "NEM 3.0" or the successor tariff. NEM 3.0 is assumed to begin in year 2022. The interconnected NEM PV capacity (kW) is further broken out by customer class (i.e., residential, small commercial, medium, and large industrial commercial, and agricultural), by rate schedule, and by whether the customers take service on tiered rates, time-of-use (TOU) rates with outdated (legacy) TOU

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[144] This definition is generally consistent with the *cost misalignment* that E3 identifies in the Successor Tariff Whitepaper. The cost misalignment equals *total costs* of the NEM tariff to other customers and the system minus *total benefits* to the system and other customers. According to the Whitepaper, *Total costs* equals total customer bill savings of on-site generation *plus* NEM interconnection costs *plus* utility incremental metering costs to track NEM generation, and *total benefits* equals avoided costs value using the most recently adopted avoided costs in the Integrated Distributed Energy Resources proceeding (R.14-10-003).

is the cost burden E3, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," January 28, 2021, pp. 3, 10-11.

[145] The forecast does not assume any changes to rate design.

periods, or TOU rates with the current TOU periods.[146] This information is used to determine the total customer bills savings and total avoided costs. The following equation[147] simplifies the cost burden calculation.

Equation 1. Calculation of Total NEM Cost Burden Per Year by Customer Class

$$Cost\ Burden_{yj} = PVkWh_{yj} \times (Retail\ Energy\ Rate_j - Avoided\ Cost)$$

Where
y = year the cost burden is evaluated
j = customer class (e.g., residential, small commercial, medium, and large industrial, and agricultural)
$PVkWh_{yj}$ = total annual solar production (kWh) in year "y" attributed to class "j"
$RetailEnergyRate_j$ = the average PV-weighted retail rate attributed to class "j" ($/KWh).
Avoided cost = average avoided costs of PV generation ($/kWh).

First, the compensation rate is calculated for each rate component (e.g., distribution, generation, Public Purpose Program (PPP) etc.) for each rate schedule. For rate components that are not time-differentiated, the average compensation rate tied to that rate component over the year is equal to the current retail rate. For rate components that vary by TOU period, such as generation rates, the compensation rate is equal to the sumproduct[148] of the retail rate for each TOU period multiplied by the proportion of annual solar production that occurs during each TOU period (PV annual production weights by TOU period).

[146] Cal Advocates does not use the term "grandfathered" to refer to NEM customers who are on rates with legacy TOU periods, because grandfathering is a term from the era of racist Jim Crow laws. Instead, Cal Advocates refers to NEM customers who take service on TOU rates with outdated TOU periods as "legacy TOU" customers.

[147] Thus, the cost burden for each year "y" for class "j" is equal to the solar PV production attributed to each class multiplied by the difference between the retail rate and avoided cost. The cost burden amounts are calculated on a rate schedule basis and for each function (e.g., distribution, transmission, generation etc.) and are then aggregated to the class and IOU level.

[148] A sumproduct means that the retail rate of each TOU period is multiplied by the amount of PV generation in each TOU period, then all of the compensation amounts by TOU periods are summed together.

Equation 2. Calculation of Annual Average Compensation Rate of ($/kWh) of PV Generation for an Individual Rate Schedule and Individual Rate Component

$$AvgComp = \sum_{i}^{n} Retail\ Rate\ by\ TOU_i \times Annual\ TOU\ Production\ Weight_i$$

Where AvgComp = Average annual compensation rate ($/kWh) of a particular rate component (e.g., generation, distribution) of a rate schedule

i = first TOU period (e.g., summer on-peak)

n = last TOU period (e.g., winter super off-peak)

Retail Rate$_i$ = the volumetric rate of particular rate component of a rate schedule attributed to TOU period "i"

Annual TOU Production Weight$_i$ = Percentage of total annual solar PV production occurring during TOU period "i"

Once the average compensation rate is calculated for each TOU period,[149] Cal Advocates multiplies the average compensation rate by TOU period by total annual PV kWh generation of each TOU period for each rate schedule, to yield the total NEM customer compensation (total bill savings) by rate component of each rate schedule. Then Cal Advocates sums the total NEM customer bill savings across all rate schedules within each customer class to yield the total NEM bill savings by customer class. The annual bill savings of each rate component are then aggregated to yield the total NEM compensation, or total NEM bill savings, of each customer class.

1. Assumptions for forecasted changes in annual cost burden from 2022-2030

Cal Advocates' forecast of annual growth in the NEM cost burden incorporates the IOUs' forecasts of the roll-off of customers from the NEM 1.0 and 2.0 tariffs as these customers' 20-year transition periods expire.[150] The analysis uses the California Energy Commission's 2020 California Energy Demand Update (CEDU) forecast of annual growth in BTM PV capacity[151] to estimate growth in successor tariff PV capacity (kW) from 2022-2030. In addition, Cal

[149] This includes the portion of retail rates that vary by TOU period and the portion that is non-time varying and is recovered as a flat rate ($/kWh) across all TOU periods.

[150] The model assumes no compensation of on-site generation after the customers roll off their NEM 1.0 or 2.0 tariffs.

[151] It is based on the CEC's mid-demand, mid-PV forecast.

Advocates applies a PV annual system degradation factor of 2% to simulate system-wide declines in PV production over time.[152]

Cal Advocates escalates the annual bill savings at 4% per year to escalate with retail rates. This assumption is consistent with the Commission's adopted standardized inputs and assumptions for calculating bill savings estimates for residential PV systems. In D.20-08-011, the Commission directed solar vendors, installers, and financing entities to provide customers with estimates of total bill savings over the first 20 years following interconnection of their system using the most recent five-year annual average increase in residential rates from U.S. Energy Information Administration (EIA).[153] The five-year average annual increase in electric rates used to calculate customer bill savings is capped at 4.0%, although if Staff's analysis finds that the most recent rolling five-year average is at least 2.0% higher than the cap (at least 6.0%) the Decision permits Staff to update the cap to the most recent value.[154]

A 4% annual escalation of NEM bill savings is consistent with the rate at which retail rates have increased over the last six years for the three large IOUs as calculated from filings at the Commission. Cal Advocates closely tracks increases in the residential average rates (RAR) for the three IOUs using the utilities' advice letter filings. The table below compiles the RAR between 2016 and 2021.

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[152] Cal Advocates calculates the capacity-weighted average age of NEM 1.0, NEM 2.0, and successor tariff systems (separately) in a given year and applies the resulting system-wide degradation factors to the capacity factors of NEM 1.0, 2.0, and successor tariff systems. The system degradation factor includes all factors that reduce system-wide PV production over time, including light-induced module degradation, panel soiling, vegetation growth, maintenance, system availability, fire, theft, and other factors. The 2% rate is the result of Itron's regression analysis of California Solar Initiative (CSI) PV system degradation rates. Itron and Verdant, LLC, "California Solar Initiative (CSI) Final Impact Evaluation," January 28, 2021, p. 78.

[153] Solar vendors, installers, and financiers are also allowed to present alternative bill savings estimates alongside the estimates using the Commission's standardized inputs and assumptions, but the alternative estimates must still use the annual escalation rate of electric rates as calculated using the Commission's adopted method, i.e., the five-year annual average method. D.20-08-001, p. 6.

[154] D.20-08-001, pp. 18-19.

Table 2A-1
Average Annual Increase in Residential Average Rates (RAR)
of the Three Major IOUs over 2016-2021

Residential Average Rate 2016-2021 (cents/kWh)						
	PGE	Source Advice Letter	SCE	Source Advice Letter	SDGE	Source Advice Letter
2016	18.97	4696	17.1	3319-E-A	23.05	2840-E
2017	19.97	4902-E-B	17.9	3515-E-A	25.51	3028-E
2018	19.52	5135-E	18.2	3695-E-A	28.92	3167-E
2019	20.70	5376-E	18.0	3896-E-A	27.65	3326-E
2020	23.29	AL 5661-E	18.9	AL 4116-E-A	28.59	AL 3487-E
2021	24.30	6004-E-B	22.0	4377-E-A	31.94	3669-E-A
Average Change	5.08%		5.17%		6.74%	

Between 2016 and 2021, the average annual increase in the RAR for PG&E, SCE, and SDG&E are 5.08%, 5.17% and 6.74% respectively. Therefore, Cal Advocates' use of a 4% annual average increase is conservative, but it is consistent with D.20-08-011.

Finally, Cal Advocates converts future cost burdens to real dollars ($2021) using the 10-year average inflation rate (2010-2020) in urban consumer goods (1.7%) to remove the effect of inflation from the calculations.[155]

2. The cost burden equals total customer bill savings minus total avoided costs

To estimate the total benefits that NEM customers' PV generation provides to the system, Cal Advocates uses the hourly avoided costs from the 2021 Avoided Costs Calculator (ACC) over the year weighted by an annual hourly PV production profile,[156] to yield a single annual PV-weighted average avoided costs value of solar PV ($/kWh) for each IOU.[157] Cal Advocates

[155] The inflation rate is the average annual change in the U.S. Bureau of Labor Statistic's Consumer Price Index for Urban Consumer Goods over 2010-2020. U.S. Bureau of Labor Statistics, Consumer Price Index News Release, 1/21/2021, accessed 4/5/2021 at https://www.bls.gov/news.release/archives/cpi_01132021.htm.

[156] Cal Advocates uses a PV production profile from PVWatts for PG&E and SDG&E, although the PV profile for SCE is an aggregation of actual residential PV production data.

[157] Cal Advocates' annual average avoided costs calculations of PV include all avoided costs components from the 2021 ACC. For instance, the average annual avoided costs of PV in 2021 is $0.04773/kWh for PG&E, $0.05477/kWh for SCE, and $0.04530/kWh for SDG&E. Cal Advocates workpapers "1.

multiplies the average avoided costs of PV ($/kWh) by total annual PV generation (kWh) by customer class to yield the total avoided costs provided by NEM customers of each customer class. Finally, Cal Advocates subtracts the annual avoided costs associated with the total solar production attributed to each customer class from each customer class' annual bill savings to yield to the annual cost burden. The result is summed across all customer classes. An example is provided below for the NEM 2.0 tariff for the three major IOUs:

Table 2A-2
Calculation of Total NEM 2.0 Cost Burden by IOU in 2021

	PG&E ($MM 2021)	SCE ($MM 2021)	SDG&E ($MM 2021)
Total NEM Customer Bill Savings	$1,290.75	$779.82	$403.06
Total Avoided Costs	$263.66	$205.83	$74.22
Total Cost Burden	**$1,027.09**	**$573.98**	**$328.84**

Table 3A-2 demonstrates the large difference between the total bill savings that NEM customers receive on the NEM 1.0 and 2.0 tariffs and the total benefits (avoided costs) their generation provides to all customers and to society.

PGE_Cost_Burden_Model," "2. SCE_Cost_Burden_Model" and "3. SDGE_Cost_Burden_Model" General_Inputs tabs.

CHAPTER 2

ATTACHMENT B – Supporting Materials

ATTACHMENT 2-B. Cal Advocates' Data Requests for CARE and NEM Enrollment

See below for a summary of Cal Advocates Data Requests PGE-3, SCE-3, and SDGE-3.

Total CARE/NEM customers indicates customers who were enrolled in CARE and NEM in the identified year. 2009-2014 may be slight over-estimates, as the data from PG&E includes all customers who were *ever* receiving CARE subsidies and NEM tariffs at the same time.

Year	Total CARE/NEM Customers	Total CARE/NEM kW	Total kW installed, all customers	Total NEM customers
2009	3136	11,387	207,250	47,440
2010	4231	15,772	291,990	64,819
2011	6360	25,365	403,140	88,654
2012	9788	40,878	567,300	122,507
2013	15,357	66,149	865,380	181,143
2014	26,708	115,034	1,323,890	267,344
2015	41,746	188,400	2,094,660	408,068
2016	63,950	294,575	2,921,420	553,482
2017	74,577	344,916	3,593,070	666,695
2018	84,634	392,159	4,346,710	791,533
2019	93,871	438,036	5,210,980	934,813
2020	103,060	475,401	5,968,290	1,059,608

CHAPTER 3 A DESIGN OF AN IMPROVED SUCCESSOR TARIFF

(Witnesses: Alec Ward, Ben Gutierrez, Nathan Chau, Adam Buchholz, Kristin Rounds)

The successor tariff proposal design outlined below is aligned with statute as it strikes and appropriate balance between ensuring nonparticipants are not overburdened by the tariff's costs, growth of BTM generation adoptions in DACs, and that all customers receive a fair value for DER adoption in California. This Chapter details the following aspects Cal Advocates recommends in a successor tariff:

- Compensating a NEM participant through net billing at avoided cost to provide fair compensation for exports;
- Establishing a Grid Benefits Charge (GBC) to ensure NEM customers pay for the costs to serve them, with an exemption for lower income customers;
- Creating an Equity Charge to support NEM adoption among low-income customers and DACs; and
- Providing incentives to encourage NEM 1.0 and 2.0 participants to transition to the successor tariff to effectively reduce the cost burden.

The proposals would provide customers with just and reasonable rates while ensuring NEM customers pay their fair share for grid services. The proposed Equity Charge would also support increased adoption for customers in disadvantaged communities, while also protecting them from the NEM cost burden. Lastly, the proposals would meaningfully reduce the cost burden on all nonparticipants while providing incentives to maximize grid benefits through increased paired storage adoption.

I. EXPORT COMPENSATION: NET BILLING (A. Ward)

The Commission should replace net metering with net billing in the successor tariff.[158] Cal Advocates agrees with the Whitepaper's finding that, "the primary benefit of net billing is that allowing compensation of exports to be disassociated with the retail rate provides a more objective and transparent method, unaffected by the structure of the retail rate."[159] Under the Cal Advocates proposal for net billing, the Commission can set compensation for exported energy at a level equal to what exported energy is worth, instead of the customer's retail rate of

[158] Net billing "provides different compensation to participating customers depending on whether they consume or export the output of their BTM system," whereas net metering "provides bill credits at the retail rate for generation exported to the grid." See Whitepaper, p. 16.

[159] Whitepaper, p. 16.

electricity. As demonstrated in Chapter 2, retail electricity rates are rising rapidly. At the same time, the price of PV systems continues to fall.[160] Net billing provides "an improvement in economic efficiency compared to classic NEM."[161] The Whitepaper appropriately notes that a net billing structure would create "more opportunities to price BTM solar output at its electricity system value."[162]

Cal Advocates further agrees that "[m]oving away from net metering and towards net billing is considered a 'middle ground' approach among alternatives," as "participating [NEM] customers retain the ability to earn bill savings at the full retail rate for the remaining solar output which is consumed onsite."[163] A 2018 report by Gridworks, "Sustaining Solar Beyond Net Metering," similarly recommends reforming NEM by adopting a net billing successor tariff.[164]

II. TERMS OF SERVICE AND BILLING RULES: NET BILLING WITH NETTING DURING THE BILLING CYCLE, MONTHLY ROLL OVER, AND ANNUAL TRUE-UP (B. Gutierrez)

The following sections will demonstrate that successor tariff customers should be allowed to take service on the tariff for as long as it is consistent with the Commission's rate design principles and the Commission authorizes the IOUs to allow customers to continue to take service on the tariff, but there should be a rate design review of the tariff after five years to ensure the tariff adequately reflects the costs and benefits of successor tariff customers' usage behavior and to safeguard nonparticipants' rates. Section B demonstrates that there should be no netting of a customer's metered consumption and net export meter readings (instantaneous netting) to ensure the most accurate, cost-based compensation of all net exports and to eliminate the risks to ratepayers of having to over-compensate DER customers for their net exports at the full retail rate. Finally, successor tariff customers should be allowed to net their export credits

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160 SEIA/Wood Mackenzie Power and Renewables. US Solar Market Insight 2020 Q4. Accessed February 22, 2021. Available at https://www.seia.org/solar-industry-research-data.

161 Whitepaper, p. 16.

162 Whitepaper, p. 16.

163 Whitepaper, p. 16. The Whitepaper notes that net billing is a "middle ground" between the current net metering structure, and a "buy all, sell all" structure where "the customer must pay for their gross usage at the retail price, and therefore generation that is consumed onsite is valued at the difference between the retail tariff and the sales price."

164 Gridworks, "Sustaining Solar Beyond Net Metering," January 2018, p. 10.

against the same cost component[165] of their bill within the same billing cycle, and they should be allowed to carry forward excess export credits to future months until their annual net surplus compensation true-up.

A. Successor Tariff Customers Should be Allowed to Take Service on the Tariff for as Long as it is Offered, but There Should be a Full Rate Design Review Process After Five Years to Protect Nonparticipants

The rates authorized by the Commission are subject to change depending on conditions such as underlying system costs, Commission rate design policies, other policy goals, impacts on ratepayers, and the availability of other tariff offerings. As is the standard practice for most tariffs, participants of the updated successor tariff should be allowed to take service on the tariff for as long as the Commission authorizes the IOUs to provide the tariff. However, the Commission should conduct a review of the successor tariff after five years following its implementation, to evaluate what, if any, changes may be necessary. Review of the successor tariff should be based on actual observed customer adoption, system design, consumption, and exports behavior to account for impacts on nonparticipants, changes in technology adoption, consistency of the tariff with the underlying costs and benefits of successor tariff customers, and consistency with the Commission's policy goals.

Evaluation of rate designs by the Commission is nothing new. Review of TOU periods after TOU rates have been in place for several years is a common feature of TOU rates. For instance, when the Commission adopted guidelines for TOU rates,[166] the Commission determined that TOU periods should be in place for at least five years with the goal of re-setting the Base TOU periods in every other General Rate Case (GRC) Phase 2 cycle.[167] The Commission also allowed the IOUs to propose changes to TOU periods more frequently than 5 years if there are substantial changes in system costs (marginal costs), which helps to minimize any large conflicts between the TOU rates and the underlying costs to serve customers. Thus, the Commission directed the IOUs to review changes in marginal costs by TOU period in every GRC Phase 2 and gave them permission to propose changes to TOU periods more frequently if

[165] The three relevant cost components are generation, distribution, and transmission costs.

[166] See: Decision 17-01-006.

[167] D.17-01-006, p. 46.

the deviation of actual from forecasted marginal costs exceeds an established marginal costs tolerance range.[168]

In addition, the Commission has addressed review of several rates designed for customers who own DERs upon adoption of the rate. In its decision adopting SDG&E's EV-HP rate[169] (D.20-12-023), the Commission included a requirement for SDG&E to hold a public workshop within 14 months of implementing the rate to consider adjustments to the rates based on data collected on EV use cases and the costs to serve EV-HP customers, including assessment of whether SDG&E should create a separate EV-HP customer class.[170] The Decision adopting PG&E's Business Electric Vehicle rates (D.19-10-055) states it is reasonable for PG&E to maintain the approved Business Electric Vehicle rate design until its 2023 GRC Phase 2, at which point it can propose changes to the rate design.[171] The 2023 GRC Phase 2 rates would likely be implemented in 2025,[172] or five years after the Business Electric Vehicle rates were first implemented (May 2020). Finally, in D.18-11-027 regarding SCE's 2018 GRC Phase 2, the Commission adopted the Small Commercial and Residential Rate Design Settlement Agreement, including the proposed TOU-D-PRIME rate[173] and the Settlement's requirement for a meet and confer process among the parties to consider modifications of the TOU-D-PRIME rates if total annual revenues shifted under TOU-D-PRIME relative to the default TOU rate reaches $50 million per year.[174]

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[168] That is, the IOU compares it current TOU marginal costs to the marginal costs it forecasted at the time the TOU periods were created. The IOU is allowed to propose changes to TOU periods more frequently than 5 years if the difference between actual and forecasted marginal costs exceeds the acceptable error range determined by the Commission (the "dead band"). This type of marginal costs analysis is called a dead-band tolerance range analysis. D.17-01-006, p .46

[169] The EV-HP rate is designed for all separately metered EV charging loads with aggregate customer non-coincident demand of at least 20 kW, excluding residential single-family homes. D.20-12-023, p. 9.

[170] The Decisions also required SDG&E to file a report within 12 months of implementing the rate with analysis of the rate. D.20-12-023, pp. 25, 27, COL 19, 20, OP 4, 5.

[171] However, D.19-10-055 also explicitly states it does not prevent PG&E from proposing modifications to the rates in a Rate Design Window proceeding prior to its 2023 GRC Phase 2. D.19-10-055, p. 39.

[171] D.19-10-055, pp. 38-39.

[172] D.19-10-055, p. 38.

[173] TOU-D-PRIME is an opt-in residential TOU rates designed for high usage residential customers who own EVs, storage, or heat pumps.

[174] D.18-11-027, pp. 43, 36.

Conducting a review of rates after they have been implemented for several years is a best practice for DER rates that ensures the rates consistently reflect the costs to serve these customers, changes in underlying marginal costs and grid conditions, and that cost burdens to nonparticipants are minimized. The Successor Tariff, like many of the aforementioned rate designs, is expected to include innovative rate design features and it is uncertain which technologies customers will adopt and how customers will respond to the rates.[175]

A rate design re-evaluation process would enable the Commission to examine data based on actual technology adoption, system design, and the costs and benefits to the system of the customers' behavior and to ensure the rates maintain alignment with policy goals and minimize harmful impacts to nonparticipants. As the 2018 SCE GRC Phase 2 Small Commercial and Residential Rate Design Settlement Agreement states, the meet-and-confer process that is triggered by $50 million of annual revenue shifting is one of the Settlement's "safeguards to help keep rates affordable for non-DER customers."[176] Since the expected cost burdens resulting from the successor tariff are much larger than in any other DER rates (e.g. $3.53 billion total per year in 2030 with no reforms or $1.78 billion under Cal Advocates' proposal), the Commission should enact even stronger safeguards to protect nonparticipants. This would ensure that the Commission's climate, clean energy, and other policy goals are met without sacrificing rate affordability of all customers.

B. Netting of kWh Should be Instantaneous While Customers Should be Able to Net their Export Credits Against their Total Bill Within Each Billing Cycle

There are two forms of netting that are relevant under a net billing tariff: the netting or measurement of kWh of exports and consumption in each billing cycle, and the ability of customers to net credits for their exports against their bills at various granularities such as at time scales shorter than or equal to a billing cycle, or longer time scales. The improved successor tariff should employ instantaneous netting of exports (kWh) and consumption (kWh) while

[175] These include, for example, Cal Advocates' proposal for net billing with the exports rates setting at varying levels by TOU period and for a grid benefits charge to reflect successor tariff customers' total cost of service responsibility.

[176] A.17-06-030, Motion for Adoption of Small Commercial and Residential Rate Design Settlement Agreement, p. 18.

allowing customers to apply their exports credits to their bills within the same billing cycle.[177] With instantaneous netting, customers would receive full retail rate compensation for generation that occurs simultaneously (instantaneously) with consumption, whereas all generation that is physically exported to the grid would receive a different value for compensation, such as avoided costs.

The IOUs' meters automatically perform instantaneous netting of customers' exports and consumption and do not require any modifications to implement this practice under net billing. The three largest IOUs all employ advanced metering infrastructure that track customer consumption and exports on two separate channels of the meter. Channel 1 tracks all electricity (kWh) that is delivered *to* the customer's premise for consumption (net or metered consumption[178]), while Channel 2 tracks all electricity that flows from the customer's premise to the grid (net exports).[179] Any on-site generation that occurs *in excess* of the customer's consumption in real time is exported to the grid and is captured in Channel 2 readings (net exports). Any on-site generation occurs *simultaneously* with a customer's consumption and up to the customer's instantaneous demand is consumed on-site, which automatically reduces the kWh that are delivered from the utility to the customer, i.e., their Channel 1 meter readings. Thus, regardless of the IOUs' meter reading intervals, the IOUs' advanced metering infrastructure automatically performs instantaneous netting because they track all physical net consumption[180] and net exports in two separate channels.[181]

Adopting instantaneous netting means there should be no netting of Channel 2 meter readings (kWh) against Channel 1 meter readings (kWh), and instead all Channel 1 readings should be billed based on the customers' underlying tariff while all Channel 2 readings should be credited at the approved export compensation rates. The netting of exports (Channel 2) against

[177] Net exports is the technical term for exports (delivery of electricity from the premise to the system) under net billing.

[178] Metered consumption refers to a customer's gross consumption net of simultaneously occurring on-site generation.

[179] Net exports refers to any instance in which the customer's on-site generation exceeds their consumption, meaning that the amount of generation in excess of consumption is exported to the grid. SDG&E response to Cal Advocates DR 13 Q2. See Attachment 3-D.

[180] Metered consumption and net consumption are synonymous terms. See footnote 64.

[181] SDG&E response to Cal Advocates DR 13 Q2a. See Attachment 3-D.

consumption (Channel 1) is a NEM construct that does not reflect the physical reality that all Channel 2 meter readings are exported to the grid, which results in significant over-compensation and ratepayer costs for net exports. The successor tariff should employ instantaneous netting to accurately compensate customers' net exports and ensure customers pay retail rates for all consumption. Adopting instantaneous netting would eliminate cost increases to ratepayers that result from paying for any net exports at greater than avoided costs value (which creates a cost burden associated with net exports).

As explained in Cal Advocates' party proposal, a customer should be allowed to accrue net exports credits based on the avoided costs value of exports and apply those credits against their bill. Under Cal Advocates' proposal, the export compensation rates are divided into three cost categories—generation, distribution, and transmission, and the monthly export credits should be applied to the same cost component of the customer's bill. This application of credits would maintain some consistency with cost causation because, for instance, an excess of benefits to the generation system in a given month does not reduce the utility's distribution costs. It would also encourage customers to follow TOU price signals in their exports behavior, because a rate component that is fairly flat (little time differentiation) could not be used to offset another rate component that is highly time differentiated. Any excess export credits should be trued up at the end of the year following the date of the customer's interconnection at wholesale energy market prices, consistent with the current NEM 2.0 net surplus compensation process (the annual true-up).[182] This annual true-up would prevent customers from oversizing their systems beyond their annual usage and carrying forward credits beyond a single year, which would blunt important time-varying and other marginal cost-based price signals the following year. For the reasons stated above, the successor tariff should employ instantaneous netting of exports (kWh) and consumption (kWh) while allowing customers to apply their exports credits to their bills within the same billing cycle.

[182] Cal Advocates' party proposal mistakenly stated that customers' annual true-up should be at the end of the calendar year, but the NEM 2.0 annual true up is based on the date of the customer's interconnection.

III. THE AVOIDED COST CALCULATOR PROVIDES FAIR EXPORT COMPENSATION VALUE (A. Buchholz and K. Rounds)

NEM provides unreasonable program incentives because it compensates participants for exported energy at retail electric rates, which today are much higher than the value of the electricity produced, as detailed in Chapter 2 of this Testimony.

Retail electricity rates are rising, and NEM is responsible for a significant portion of these increases.[183] To correct for NEM's over-compensation through use of the current retail rate, the NEM export compensation instead should reflect the most recent avoided cost values adopted by the Commission in the Integrated Distributed Energy Resource proceeding, Rulemaking (R.) 14-10-003.[184] These values should be produced through the prevailing Avoided Cost Calculator (ACC) 1-year values to ensure the value of exported energy is compensated accurately and in accordance with the benefits BTM generation systems provide to the larger grid.[185] The Whitepaper points out that for these reasons, states across the country are reforming NEM, moving away from retail rates.[186]

Decision (D.) 20-04-010 in the Integrated Distributed Energy Resources proceeding adopted the 2020 ACC, which leverages inputs from the Integrated Resource Planning (IRP) (R.16-02-007) and Distributed Resource Plan (R.14-08-013) proceedings. The Commission emphasized that coordinating the ACC with the IRP process was critical for maintaining consistency in the evaluation of supply- and demand-side resources in electric sector planning.[187] Accordingly, aligning net billing with the values of the ACC would better support the grid planning efforts of the IRP and Distributed Resource Plan proceedings. Additionally, using the ACC values would align with the proposals presented in the Whitepaper.[188] The 2021 ACC will be pending adoption by the Commission at the time of this filing. Cal Advocates supports the

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[183] "Designing Electricity Rates for An Equitable Energy Transition" by Next 10 and the Energy Institute at Haas, p. 28.

[184] See Chapter I (A), above.

[185] The current Avoided Cost Calculator is available at: https://www.cpuc.ca.gov/General.aspx?id=5267.

[186] Whitepaper, p. 34. See, New York, Hawaii, and Arizona.

[187] *Decision Adopting 2020 Policy Updates to the Avoided Cost Calculator,* Decision (D.) 20-04-010, R.14-13-003, filed April 16, 2020, pg. 24.

[188] Whitepaper, p. 15. ("We propose that the excess generation not consumed onsite be valued at system, time-differentiated avoided costs, i.e., using a "net billing" approach with exports compensated at avoided costs.)

proposed changes made to the calculator as outlined by Energy Division staff in Draft Resolution E-5150 and reaffirms our position that the NEM export compensation values should reflect the prevailing calculator's avoided cost values.[189]

The ACC sufficiently values the benefits provided by BTM generation through the avoided cost values of greenhouse gas (GHG) emissions, transmission capacity, distribution capacity, energy, and system generation capacity. The methods underlying these categorical avoided costs values are summarized below.

1. Avoided Greenhouse Gas Emissions

The avoided cost of GHG emissions estimated by the ACC is calculated by determining both the avoided *amount* of emissions from the electric grid and the *value* of those emissions that would be associated with a given Distributed Energy Resource (DER) measure. The value is based on the GHG shadow price, which represents the cost of reducing an additional unit of GHGs in each year.[190] In order to best reflect the value of GHG reductions over the next decade, the 2030 GHG shadow price from the Renewable Energy Solutions Model is discounted for 2020-2029 based on the utility weighted average cost of capital.[191] The amount of emissions, or the actual impacts on emissions output from DER measures, is calculated through a two-step approach that first derives marginal emissions and then rebalances the portfolio so annual GHG intensity targets are met.[192]

D.20-04-010 in the Integrated Distributed Energy Resources proceeding, which adopted 2020 updates to the ACC states this method "offers the best proposal in the record to address the

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[189] *Draft Resolution E-5150 Adopting updates to the Avoided Cost Calculator*. Served May 3, 2021. R.14-10-003. California Public Utilities Commission Energy Division. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M382/K179/382179225.PDF.

[190] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, pg. 21. Available at https://www.cpuc.ca.gov/General.aspx?id=5267.

[191] The Renewable Energy Solutions Model is a publicly available resource planning model created by E3 that is used in the IRP proceeding. This model is used to create the final Reference System Plan (RSP). The models, inputs, and results are available here: https://www.cpuc.ca.gov/General.aspx?id=6442464143.

[192] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 24.

concern that GHG costs have been overestimated."[193] The approach the ACC used to calculate avoided GHG costs is similar in concept to both the fuel substitution test (D. 19-08-009) used for energy efficiency, and for the California Energy Commission's (CEC) Title 24 building standards.[194] The 2021 ACC utilizes the same method for GHG calculations. Changes in the GHG value for the 2021 ACC can be attributed to the changes of the cost inputs for utility-scale solar and storage.[195] Therefore, the ACC method for valuing GHG avoided costs is the best approach for quantifying the environmental benefits associated with DER installations and is the appropriate benchmark for NEM billing.

2. Transmission Capacity

The ACC provides a quantification of transmission avoided capacity costs to represent the estimated cost impacts on utility transmission investments as a result of peak load reductions.[196] Because the ability to avoid transmission investment projects is dependent on a variety of specific factors, the avoided cost values are not associated with any "specified" transmission deferral projects. Those projects that provide specified benefits are evaluated in the CAISO Transmission Planning Process and Commission transmission permitting process and are not incorporated into the ACC.[197] The "unspecified" transmission avoided cost values within the ACC represent the value provided by a DER if the peak load reductions can be obtained in the right amount, right location, and with sufficient dependability to avoid or defer a transmission

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[193] *Decision Adopting 2020 Policy Updates to the Avoided Cost Calculator,* Decision (D.) 20-04-010, R.14-13-003, filed April 16, 2020, p. 47.

[194] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 24.

[195] *2021 Distributed Energy Resources Avoided Cost Calculator Documentation. Version 1a*. May 3, 2021. California Public Utilities Commission, p. 30. Available at: https://www.cpuc.ca.gov/general.aspx?id=5267.

[196] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 36.

[197] CAISO has integrated Non-Wires Alternatives into their Transmission Planning Process. As stated in CAISO's 2019-2020 Transmission Planning Process Final Study Plan issued on April 3, 2019, if reliability concerns are identified during the initial transmission assessment CAISO will perform additional assessments in order to determine if demand response or energy storage could act as a potential mitigation measure. *Decision Adopting Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values.* Decision (D.) 20-03-005, R.14-08-013, filed March 18, 2020, p. 7.

investment.[198] These avoided costs are calculated through the marginal cost of transmission, which is derived from either the IOUs' GRC Phase 2 proceedings or information obtained through data requests.[199] Transmission marginal costs are based on the capacity-driven projects for each utility's transmission plan incorporated into the respective GRC filings, and estimated using the Discounted Total Investment Method.[200]

The Commission deemed this approach as the appropriate valuation method for transmission avoided costs within the 2020 ACC in D.20-04-010.[201] The Commission also vetted this approach in the Distribution Resource Plan Proceeding (R.14-08-013) and adopted it in D.20-03-005. Cal Advocates agrees with the Commission that the ACC's approach is the best methodology available for calculating these costs, as any specified transmission deferral costs associated with a DER installation are appropriately evaluated through the CAISO Transmission Planning Process and the Commission transmission permitting process.

The approach for valuing the avoided cost of transmission capacity in the 2021 ACC utilizes the same inputs and methods as the 2020 ACC. Under the proposed successor tariff, NEM systems would not be exempt from the Transmission Access Charge as their benefits to the transmission system would be accounted for with the ACC. Transmission owner's transmission capital costs and operation and maintenance costs should be socialized across all ratepayers since all energy users benefit from the transmission system. Any successor tariff should utilize the prevailing ACC to account for the avoided costs of transmission investments that can be attributed to BTM generation.

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[198] *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, *Version 1c*. June 24, 2020. California Public Utilities Commission, p. 36.

[199] PG&E provides transmission marginal capacity costs in their GRC filings, SCE provides their transmission marginal capacity costs through data request responses to Energy Division, and SDG&E's transmission marginal capacity costs are calculated with IEPR load forecasts. See the 2021 ACC documentation for more detail, p. 43. See: https://www.cpuc.ca.gov/general.aspx?id=5267.

[200] SCE's transmission marginal capacity costs additionally use the LNBA method for the Aberhill project. See the 2021 ACC documentation for more detail, p. 46. See: https://www.cpuc.ca.gov/general.aspx?id=5267.

[201] *Decision Adopting 2020 Policy Updates to the Avoided Cost Calculator,* Decision (D.) 20-04-010, R.14-13-003, filed April 16, 2020, p. 61.

3. Distribution Capacity

Similar to the transmission capacity avoided costs, the avoided costs for distribution in the ACC represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs and represent "unspecified" deferral or avoidance values. The costs are derived through a system-average approach and are based on data from the utility's Distribution Deferral Opportunity Report, Grid Needs Assessment, and GRC filings.[202] The IOU's calculate specified distribution avoided costs as part of the annual Distribution Deferral Opportunity Report process. These avoided costs are specific to utility capacity projects that could be potentially deferred through DER adoptions in identified project areas are valued through Distribution Investment Deferral Process solicitations and the Partnership Pilot Tariff. Specified avoided distribution costs are not valued in the ACC.

The avoided cost values for distribution capacity adopted by the Commission in D.20-04-010 are modeled to capture the long-term value that BTM generation can provide in deferring distribution system upgrades. The method is adjusted to fit the distribution needs of each IOU (based on their respective Grid Needs Assessments) and is vetted in the Distributed Resource Plan proceeding.[203] The proposed 2021 ACC retains the avoided distribution capacity costs from the 2020 ACC, with the only change being the removal of secondary distribution costs from the calculation of PG&E's long-term avoided distribution costs.[204] The ACC accurately values the benefits of unspecified deferred or avoided distribution system investments that can be attributed to BTM generation in both versions of the calculator. Any successor tariff should utilize the 2021 ACC.

4. Energy Generated

The ACC uses the Strategic Energy Risk Valuation Model[205] to project energy prices until 2030. The model simulates the wholesale price of energy based on projected generation portfolios and weather forecasts. The modeling scenario used for the ACC assumes no new

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[202] For detailed descriptions of the avoided distribution cost methodologies, see the 2020 ACC documentation at https://www.cpuc.ca.gov/General.aspx?id=5267.

[203] The 2021 calculator maintains the same approach as 2020, though the secondary distribution costs from the calculation of PG&E's long-term avoided distribution costs has been removed. See the 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267.

[204] See the 2021 ACC documentation for more detail: https://www.cpuc.ca.gov/general.aspx?id=5267.

[205] 2021 Avoided Cost Calculator Documentation, p. 5.

BTM generation, thus giving an estimate of the marginal impact of a new DER.[206] These values are used to estimate the dollar value of energy generated by a DER and are an essential component of estimating the avoided costs of energy. Any successor should utilize the 2021 ACC for valuing energy from BTM generation.

5. System Generation Capacity

System generation capacity indicates the DER's contribution to avoided grid peak capacity costs. The ACC uses E3's Renewable Energy Solutions Model to estimate the Net Cost of New Entry of a 4-hour battery with optimal dispatch according to the CEC Solar + Storage Model. These Cost of New Entry values are subtracted from the levelized fixed costs of the battery to generate the Net Cost of New Entry. The value of this dispatch is allocated to the hours of the year with the highest system capacity need according to the E3 Renewable Energy Capacity Expansion model, which results in allocation of these values to evening hours in late Summer and early Fall.[207] Any successor tariff should utilize the 2021 ACC.

IV. RATE STRUCTURE: TIME-OF-USE RATES (B. Gutierrez and N. Chau)

The improved successor tariff should function as a rate overlay to existing TOU rates that are open to customers by the time the improved successor tariff is in place.[208] TOU rates are necessary for recovering marginal costs that vary by time period. The TOU periods with the highest costs and tend to be when customer demand is greatest, and the availability of capacity is the lowest relative to demand (peak-related or time-varying marginal costs). A well-designed TOU rate can better align recovery of costs with how they are incurred, which can reduce the NEM cost burden in addition to providing proper price signals to pair other BTM generation with solar PV. A rate overlay approach would also preserve customer choice and allow customers who own additional clean technologies like EVs to choose among multiple TOU rate offerings. This choice would enable customers to select a rate that best aligns with their usage pattern, and their ability and willingness to respond to different time-based price signals.

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[206] 2021 Avoided Cost Calculator Documentation, p. 11.

[207] 2021 ACC Documentation p. 41.

[208] For instance, a customer who only has rooftop solar PV should not be allowed to take service on a TOU rate designed specifically for EVs and storage.

This customer choice based approach is consistent with the Commission's guidance in D.17-01-006 of the TOU order instituting rulemaking (R.15-12-012) which encouraged parties to work in utility-specific rate design proceedings to develop "a menu of different TOU and other time-varying rates as a way to maximize customer acceptance by providing a range of rates that will be appropriate for different levels of customer sophistication, technology, and understanding."[209] As D.17-01-006 recognized, offering customer choice among TOU rate options also promotes customer acceptance, which is an important part of the success of any new rate.[210] The Commission should allow customers to take service on any TOU rates have the most updated TOU periods.[211] Successor tariff rates for consumption and exports must reflect accurate, cost-based groupings of underlying marginal costs and current grid conditions and TOU rates that align closer to costs will maximize benefits to all ratepayers.

V. EXPORT COMPENSATION AND COST RECOVERY (B. Gutierrez and N. Chau)

While requiring successor tariff customers to take service on TOU rates with updated TOU periods can improve the NEM cost burden outlook by better aligning rates with costs, it is not enough to address the large difference between customer on-site compensation and avoided costs value. Simply setting exports compensation at avoided costs would not mitigate the harmful impacts on nonparticipants' rates, because TOU rates still collect most costs in volumetric rates, which are offset by PV generation. Therefore, as discussed in detail in section B below, the improved successor tariff should include a GBC to accurately reflect the costs of

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[209] D.17-01-006, p. 43, FoF 41, Appendix 1 p. 2. All three IOUs now offer default or mandatory TOU rates, which feature the simplest TOU periods that new customers can take service on and that accurately reflect underlying patterns of marginal costs. In addition, the IOUs offer optional TOU rates that feature a combination of alternative TOU period configurations, stronger TOU price differentials, and dynamic pricing components.

[210] D.17-01-006, p. 39, FoF 42.

[211] This includes rates that were adopted by the Commission in the most recent GRC Phase 2 or RDW that set default TOU periods, or more recently. For instance, PG&E proposed an optional E-ELEC rate for residential customers with BTM storage in its 2020 GRC Phase 2, even though it implemented new default TOU periods as an outcome of its 2017 GRC Phase 2. The proposed E-ELEC rate features a higher fixed charge, lower volumetric rates, and a 6-time period TOU structure that includes additional summer and winter Partial Peak periods (3-4pm, 9pm-midnight). The default rate has a simpler 4-time period TOU structure. A.19-11-019, Ex. PG&E-5, PG&E Testimony on Schedule E-ELEC, July 2020 Errata, p. 1-6.

providing distribution and transmission service to successor tariff customers and ensure fair and equitable recovery of non-bypassable charges (NBCs).

The GBC would allow the improved successor tariff to better address the cost burden. For instance, assuming all forecasted new NEM customers take service on PG&E's E-TOU-C rate schedule, the 2022 cost burden per kW decreases from $414/kW-year (2021 dollars) to $220/kW-Year when the export compensation rate is set at avoided costs. Because changing the export compensation rate only addresses the cost burden generated by net exports, there is still a $220/kW-Year cost burden that export compensation alone cannot address. The GBC addresses this shortfall, as discussed in section B. To more effectively address the NEM cost burden, Cal Advocates proposes the following additional reforms to the successor tariff:

1. Set the export compensation rates at TOU-varying avoided costs to align exports compensation with benefits.
2. Assess a monthly GBC based on the size ($/kW) of the customer's generator for distribution and transmission costs and based on their monthly gross consumption of on-site generation ($/kWh) for the four NBCs. Cal Advocates recommends the following GBC values for residential customers:

Table 3-1
Cal Advocates' Residential GBCs by Cost Component (2022)

	Component:	Proposed Units	SDG&E	SCE	PG&E
1	Distribution	$/kW	$3.40	$3.48	$4.73
2	Transmission	$/kW	$1.58	$0.72	$1.34
3	Competition Transition Charge	$/kWh	$0.00095	$0.00067	$0.00119
4	Public Purpose Program	$/kWh	$0.01553	$0.01308	0.01341
5	Nuclear Decommissioning	$/kWh	$0.00006	-$0.00053	0.00048
6	Wildfire Fund Charge[212]	$/kWh	$0.00589	$0.00608	$0.00627
7	**T&D Sub-Total**	**$/kW**	**$4.98**	**$4.20**	**$6.08**
8	**NBC Sub-Total**	**$/kWh**	**$0.02243**	**$0.01930**	**$0.02135**
9	**Total Converted Entirely to a $ per kW Basis (for informational purposes only)**	**$/kW**	**$6.14**	**$5.76**	**$7.66**

[212] This charge was formerly the Department of Water Resources Bond-Charge (DWRB-C), but the Commission approved a new wildfire charge which resulted in no change in customers' rates at that time. The wildfire charge took effect on October 1, 2020. D.20-09-005.

3. Assess a monthly GBC on non-residential customers that would only include the four NBCs included in Table 3-1 above but reflecting the then-current NBCs for each non-residential customer class.

In total, Cal Advocates' rate proposals would reduce the 2030 annual cost burden of the successor tariff to ratepayers of the three largest IOUs from $3.53 billion[213] to $1.73 billion per year in 2021 dollars, or by $1.8 billion (51.2%).[214]

A. Export Compensation Structure: Setting Exports Compensation Rates By Tou Period

Cal Advocates proposes to set the export compensation rate (ECR) at average PV production-weighted avoided costs during the middle of the day and at simple average avoided costs during evening hours. By accurately compensating solar PV exports, Cal Advocates' proposal would reduce the total successor tariff cost burden to ratepayers of the three IOUs by $1.305 billion, or by 36.9%, per year by 2030. Additionally, setting the exports compensation rate during evening TOU periods at simple average avoided cost would encourage resources to provide valuable generation during system peak hours when total avoided costs are highest.[215]

Avoided costs vary by hour, by season, and by day type throughout the year and can be grouped into sets of hours with similar overall levels of avoided costs (to establish TOU periods) to more accurately reflect the time-varying value of net exports during different seasons and times of day.[216] Avoided costs generally represent the costs *savings* of energy costs, incremental capacity costs, GHG emissions, and other regulatory costs when the utility has to serve one less unit of demand.[217] The average annual value of PV exports ($/kWh) is equal to the total hourly avoided costs from the ACC weighted by the hourly production weights of PV exports across the

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[213] This assumes no reforms, or that the successor tariff is a continuation of the current NEM 2.0 tariff.

[214] Cal Advocates cost burden workpapers are available to parties upon request.

[215] Cal Advocates uses the term "peak hours" to refer to the hours 4-9pm all days year-round, although the utilities variously term these hours as Peak or Mid-Peak periods depending on the season and weekday/weekend.

[216] Net exports occur whenever a customer's on-site generation exceeds their consumption in real time, resulting in the portion of generation that exceeds on-site consumption (net exports) being exported to the grid.

[217] This can be achieved either through consumption of on-site generation leading to a reduction in demand (metered consumption), or by a customer providing an incremental unit of supply (e.g., a kWh of net exports) that avoids the costs the utility would have incurred to provide that unit of supply.

entire year (PV production profile-weighted or PV-weighted averaged avoided costs).[218] Compensating all exports at PV-weighted annual averaged avoided costs would yield the same total compensation to customers as compensating hourly exports by hourly total avoided costs from the ACC. Therefore, the ECR should be set at PV-weighted average avoided costs during the TOU periods that cover the hours in the middle of the day using the most recent avoided costs calculator (2021 ACC) to produce cost-based compensation for the large majority of successor tariff exports that reflects their average avoided costs value.[219] Cal Advocates used avoided costs weighted by the total PV production profile of a typical residential PV system to develop its exports compensation rates, because PV exports data is not yet available for the successor tariff. This method is accurate and cost-based because it would align the average compensation of exports ($/kWh) with the average compensation based on hourly compensation of PV exports using hourly avoided costs during the mid-day TOU periods. This method would align total compensation (total costs) for the overwhelming majority of PV exports[220] with avoided costs value (total benefits), producing an equitable outcome for all ratepayers.

While the exports compensation rates of mid-day TOU periods should be set at PV-weighted average avoided costs, the exports compensation rates during the evening TOU periods should be set at simple (unweighted) average avoided costs to promote emerging technologies that can provide significantly greater capacity value and GHG emissions reductions per kWh than PV alone. System demand[221] is highest relative to available generation supply in the

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[218] The production weight is the percentage of total annual PV exports that occurs during each hour of the year.

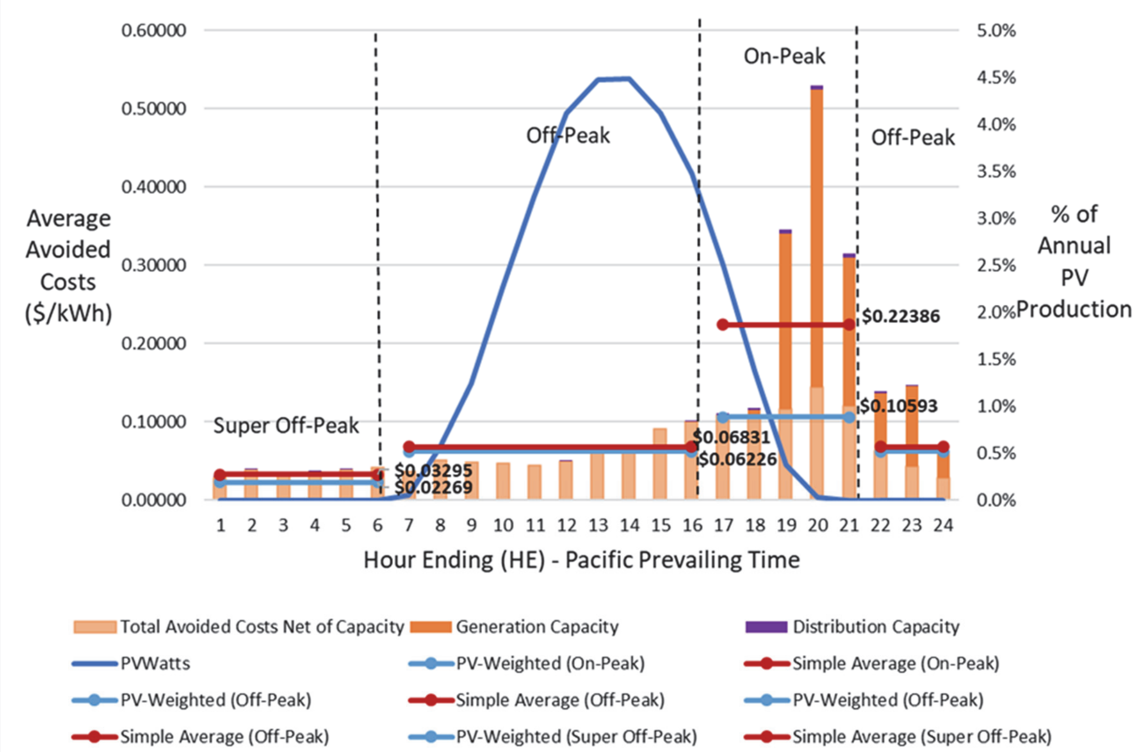
[219] Cal Advocates weighted the avoided costs by a general PV production profile from PVWatts for PG&E and SDG&E, and by an aggregate PV production profile for SCE. Technically the most accurate compensation would result from weighting the avoided costs by a PV *exports profile* (not including on-site consumption). Cal Advocates compared annual average compensation of exports under its proposal and the difference was small. In addition, exports profile under the successor tariff is likely to be different than under the current NEM tariffs due to differences in system sizing and annual exports ratios. Cal Advocates' total PV production-weighted avoided costs method is simplest and would result in reasonable compensation for PV exports that is likely close to the exports-weighted value.

[220] The mid-day TOU periods cover 94% of annual PV production for PG&E, 95% for SCE, and 95.5% for SDG&E. PG&E and SDG&E figures are calculated using profiles from PVWatts, whereas the figure for SCE is calculated using an aggregate customer PV production data. Cal Advocates ECR workpapers ("4. PGE 2021 ACC by TOU_2022 2 Periods," "5. SCE 2021 ACC by TOU_2022," "6. SDGE 2021 ACC by TOU_2022").

[221] Demand is most accurately measured using various measures of system net load, or system-level

evenings, which is the time when system generation capacity is most constrained and the CAISO is most likely to require generation from the oldest, least efficient (and most expensive), and most GHG-emitting gas-fired generators such as combustion turbine "peaker plants" to serve demand. However, the higher avoided costs value during the system peak would not be captured by using a PV-weighted avoided costs profile, because On-Peak PV generation is concentrated mostly in the hours 4-6pm when system avoided capacity costs are low. This is demonstrated in Figure 3-1 below.

Figure 3-1. Comparison of Sum of Hourly Residential PV Production (%) vs. SDG&E Average Hourly 2022 Avoided Costs (Summer Weekdays)



PV generation during the On-Peak period (4-9pm or hour ending 17-21) is almost entirely concentrated in hour ending 17-18, which have essentially zero avoided generation or distribution capacity value. As a result, the PV-weighted avoided costs during the On-Peak are

metered consumption net of clean energy generation. SCE and SDG&E use "net load," or metered load less all solar and wind generation, in their marginal generation cost analyses while PG&E uses the more complex "adjusted net load" that also subtracts nuclear, geothermal, biomass, and biogas generation. Both of these metrics are more accurate than gross load, which does not correlate as well with time-varying marginal energy costs (MEC) or marginal generation capacity costs (MGCC) on the system.

$.10593/kWh while simple average avoided costs are 111% higher or $0.22386/kWh.[222] Simple average avoided costs are similarly higher than PV-weighted avoided costs during the summer evening TOU periods for SCE and SDG&E.[223] A BTM storage device's total discharged electricity (kWh) would likely be much more spread out among the On-Peak hours, so it would provide greater capacity value to the system than standalone solar PV.[224] The exports compensation rates should be set at simple average avoided costs during all TOU periods that capture the hours 6 – 11pm,[225] which covers the hours when the system's avoided capacity costs are highest, to provide more accurate compensation to technologies that can provide high capacity value to the system and displace generation from the least efficient, highest-GHG emitting peaker plants.[226] This proposal would maximize the value of customer-sited generation to ratepayers and in support of the state's climate change goals, which is consistent with guiding principle 8's direction to maximize the value of customer-sited generation.[227]

Overall, Cal Advocates' proposal to set the exports compensation rates at average PV production-weighted avoided costs during the middle of the day and at simple average avoided costs during evening hours would provide accurate and fair compensation of solar PV exports.

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[222] Although simple average avoided costs and PV-weighted average avoided costs are very similar in the Off-Peak ($0.06831 vs. $0.06226/kWh), this is merely a coincidence.

[223] Summer On-Peak simple average avoided costs are $0.27092/kWh or 79% higher than PV-weighted AC ($0.15081) for PG&E and are in 2022. Some of the winter On-Peak simple averages are actually lower than PV-weighted averages in 2022 (e.g., $0.0848/kWh simple average vs. $0.09047/kWh PV-weighted average for PG&E). However, the 2021 ACC forecasts the winter On-Peak simple average avoided costs will increase considerably by 2030 ($0.14683/kWh winter simple average On-Peak vs. $0.06432/kWh PV-weighted average for PG&E). This is likely due to the calculator's large increase in avoided distribution and transmission costs over time. Cal Advocates PG&E ACC workpaper.

[224] It is difficult to know exactly in what hours the storage device could produce generation greater than customer consumption, resulting in net exports to the grid, but the storage dispatch algorithm would likely favor self-consumption (at full retail rates) over exports (compensated at avoided costs) so it is very unlikely the battery would output at its full power rating and produce high net exports during the first 3 hours of the On-Peak. It is more likely that discharging and the possibility of net exports would be spread throughout the On-Peak period.

[225] These hours include the IOUs' Peak and Mid-Peak periods, as well as some of the Partial (shoulder) Peak periods of PG&E's more complex optional TOU rates.

[226] In addition, this proposal could incent solar developers to install more west-facing solar panels to maximize the amount of electricity that will be exported during the evening hours. This change in system design could shift solar generation to slightly later in the day and help alleviate steep later afternoon ramps in the system net load curve, or what the CAISO refers to as the "duck curve." This change would further maximize the benefit of distributed generation to the system and to all ratepayers.

[227] D.21-02-007, p. 24.

The following table shows the average annual compensation of exports (kWh) under various exports compensation proposals in 2022 and 2030:

Table 3-2
Comparison of Average Annual Compensation of PV Exports ($/kWh) in 2022 and 2030 under Various Exports Compensation Proposals

		Average annual compensation of PV exports:		
Year	**Exports Compensation Rate Method**	**PG&E $/kWh**	**SCE $/kWh**	**SDG&E $/kWh**
2022	1. PV-Weighted AC	$0.04680	$0.05360	$0.04663
2022	2. Simple Average AC	$0.05927	$0.06007	$0.06166
2022	**3. Difference from PV-weighted AC (2-1)**	**$0.01247**	**$0.00646**	**$0.01503**
2022	4. Cal Advocates Proposal	$0.05690	$0.05961	$0.05476
2022	**5. Difference from PV-weighted AC (4-1)**	**$0.01010**	**$0.00601**	**$0.00814**
2030	6. PV-Weighted AC	$0.03328	$0.05434	$0.03737
2030	7. Simple Average Avoided Costs	$0.07869	$0.08349	$0.09367
2030	**8. Difference from PV-weighted AC (7-6)**	**$0.04541**	**$0.02915**	**$0.05630**
2030	9. Cal Advocates Proposal	$0.04435	$0.06351	$0.05033
2030	**10. Difference from PV-weighted AC (9-6)**	**$0.01106**	**$0.00917**	**$0.01296**

The PV-weighted avoided costs (lines 1 and 6) represent the most accurate annual compensation of solar PV reflecting their hourly avoided costs value. In 2022, deviations from the PV-weighted avoided costs are small and there is little difference among the various proposals (lines 3 and 5). However, by 2030 there is substantial divergence between simple average avoided costs and PV-weighted avoided costs during all TOU periods, resulting in large divergences in annual compensation rates (lines 8 and 10).

A proposal that sets the exports compensation rates at simple average avoided costs during all TOU periods would over-compensate SDG&E exports by $.05630/kWh – producing average compensation ($0.09367/kWh) that is 2.5 times the exports' avoided costs value ($0.03737/kWh) – and it would over-compensate PG&E customers' exports by $0.04541/kWh (line 8). Such large over-compensation of exports would significantly contribute to the cost burden born by nonparticipants.

In contrast, Cal Advocates' proposal would tie the large majority of PV exports compensation to their PV-weighted avoided costs value, and it would limit over-compensation to between $0.00917/kWh and $0.01296/kWh by 2030 (line 10). Cal Advocates' proposal brings average and total customer payments (costs) for exports much closer in line with total avoided costs value (benefits).[228] Overall, Cal Advocates' proposal better aligns the tariff's total costs with total benefits, while also promoting emerging technologies that can provide generation during the evening hours when system capacity is most constrained and the grid's marginal GHG emissions rates are highest.

Finally, the total average exports compensation rates by TOU period should be capped at less than the TOU retail rate to avoid undesirable system design and operation that would severely reduce the generator's value to the system and other customers. For instance, if the On-Peak exports compensation rates were set at greater than or equal to On-Peak retail rates, customers would have no incentive to offset their own consumption and they would instead be incented to discharge their battery at full power starting at 4pm (HE 17),[229] even though from 4pm to 6pm have essentially zero capacity value and much lower avoided costs than the On-Peak hours of the hours from 6pm to 9pm (see Figure 3-1). On average, residential customers' consumption tends peaks later than 3pm to 4pm period, so setting the exports compensation rates below retail rates would encourage customers to reduce their metered consumption during the hours with highest avoided costs – thus maximizing value to the system to ratepayers.[230]

Cal Advocates presents its proposed 2022 exports compensation rates by TOU period below. The ECR are presented according to each IOUs' adopted default TOU period structure for residential customers, which differs by IOU.[231]

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[228] Thus, Cal Advocates' proposal aligns with P.U. Code Sec. 2827.1(4) requiring that total benefits to ratepayers and the electrical system under the successor tariff be approximately equal to total costs.

[229] 4-5pm is equivalent to hour ending (HE) 17.

[230] If the export compensation rates are higher than retail rates, it could also create a situation in which a customers' sizing of their system has no limiting factors except for their overall budget—which could lead to over-sized systems that may overwhelm local distribution infrastructure with exported electricity, or it could lead to customer dissatisfaction and frustration if exports compensation decreases considerably below retail rates in future years, leaving customers with systems that are over-sized relative to their consumption needs.

[231] The exports compensation rates for other common TOU periods such as PG&E's 3-period TOU structure for non-residential customers are provided in Cal Advocate's Avoided Cost Calculator (ACC) workpapers, AC_by TOU tab.

Table 3-3
Cal Advocates Proposed ECR for PG&E (2-Period TOU)

TOU Period	Total ($/kWh)
Summer Peak	**$0.264109**
Summer Off-Peak	**$0.053772**
Winter Peak	**$0.078027**
Winter Off-Peak	**$0.030875**

Table 3-4
Cal Advocates Proposed ECR for SCE (Current 4-9pm TOU[232])

TOU Period	Total ($/kWh)
Summer Peak	**$0.32415**
Summer Mid-Peak	**$0.09239**
Summer Off-Peak	**$0.06300**
Winter Mid-Peak	**$0.08336**
Winter Off-Peak	**$0.04840**
Winter Super Off-Peak	**$0.02994**

Table 3-5
Cal Advocates Proposed ECR for SDG&E (3-Period TOU)

TOU Period	Total ($/kWh)
Summer Peak	**$0.22386**
Summer Off-Peak	**$0.06226**
Summer Super Off-Peak	**$0.02269**
Winter Peak	**$0.08201**
Winter Off-Peak	**$0.04309**
Winter Super Off-Peak	**$0.01793**

[232] These are currently the default TOU periods for all SCE's residential and non-residential customers.

Finally, Cal Advocates calculates that its ECR proposal would reduce the total cost burden to ratepayers of the successor tariff by $1.305 billion per year in 2021 dollars, or 36.9%, by 2030 compared to the current NEM compensation structure.[233]

By accurately aligning export compensation with the time-varying avoided costs value of exports to the system, Cal Advocates' ECR proposal is consistent with Public Utilities Code Section 2827.1 (3) which requires that the successor tariff be based on costs and benefits of the electric generating facility, and with Section 2827.1 (4) which requires that total successor tariff costs to all customers and the electric system are approximately equal to total benefits. In addition, Cal Advocates' proposal demonstrates that net billing at avoided cost is aligned with the proceeding's guiding principles to "ensure equity among customers,"[234] "maximize the value of customer-sited renewable generation to all customers and to the electrical system,"[235] "be coordinated with the Commission and California's energy policies,"[236] and "be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities."[237]

B. Grid Benefits Charge

As demonstrated in the prior section, setting the ECR at avoided costs only reduces the successor tariff's cost burden relative to the current NEM structure by 36.9%. This is because changing the ECR only addresses the cost burden generated by net exports. Consequently, there are still significantly large cost burdens remaining even with net billing. In fact, even with net billing, NEM customers are underpaying the costs they impose on the system. NEM customers' underpayment relative to their cost of service and their over-compensation relative to the value

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[233] Cal Advocates cost burden models for SCE, SDG&E, and PG&E. Business as usual assumes the successor tariff is a continuation of NEM 2.0 policies.

[234] See D.21-02-007, p. 45 "(b) A successor to the net energy metering tariff should ensure equity among customers."

[235] See D.21-02-007, p. 46: "(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."

[236] See D. 21-02-007, p. 46: "(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."

[237] See D. 21-02-007, p. 46: "(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."

their generation provides to the system are described further in Section 1 below. Section 2 describes the calculation of Cal Advocates' proposed GBCs.

The GBC should include the customers' responsibility for fixed distribution system costs – or the total costs of the system that are above marginal costs – as well as transmission costs. The costs above marginal costs include costs to maintain, replace, and upgrade distribution capacity[238] and to provide sufficiently reliable and safe electric service, which are critical components of cost of service for all ratepayers and are not affected by customers' consumption or generation decisions. Additionally, there are significant NBCs incurred that do not change when customers add on-site generation but serve important public purposes that all customers should contribute equitably toward. NEM customers should not be exempt from paying these costs. Therefore, Cal Advocates proposes a monthly GBC, which is assessed based on the system's size (kW) for distribution and transmission cost recovery and on a customer's monthly gross on-site consumption (kWh) for recovery of NBCs, to address these gaps and to reduce the cost burden further. Table 3-6 shows Cal Advocates' residential GBCs.

The Commission should adopt the distribution and transmission GBC components (lines 1-2) displayed below, and it should adopt inclusion of the four NBCs (lines 3-6) in the GBC and Cal Advocates' method for assessing the NBCs on customers' monthly on-site consumption that is described in this Testimony. The NBC values displayed in table 3-6 below are merely illustrative, and the NBCs should reflect the current NBCs at the time the tariff is adopted.

[238] The unavoidable or fixed costs of service include the equal percent of marginal cost (EPMC) scalar in the Commission's rate making terminology. EPMC revenues equal the different between system-level marginal cost revenues and the utility's approved revenue requirement. The EPMC scalars scale the marginal cost revenues to the full revenue requirement. The Commission has repeatedly stated its preference for EPMC scaling of marginal costs, which assigns costs to customer groups in proportion to the marginal costs they impose on the system. The Commission has stated that rates based on EPMC scaled marginal costs are cost-based rates and that EPMC scaling is the preferred way to achieve *fair, equitable* rates. Therefore, when NEM customers do not pay their EPMC-scaled marginal costs (cost of service), it violates the Commission's definition of fair, equitable rates. D.18-08-01. pp. 14, 18, 19.

Table 3-6
Cal Advocates' Residential GBCs by Cost Component (2022)

	Component:	Proposed Units	SDG&E	SCE	PG&E
1	Distribution	$/kW	$3.40	$3.48	$4.73
2	Transmission	$/kW	$1.58	$0.72	$1.34
3	Competition Transition Charge	$/kWh	$0.00095	$0.00067	$0.00119
4	Public Purpose Program	$/kWh	$0.01553	$0.01308	0.01341
5	Nuclear Decommissioning	$/kWh	$0.00006	- $0.00053	0.00048
6	Wildfire Fund Charge	$/kWh	$0.00589	$0.00608	$0.00627
7	**T&D Sub-Total**	**$/kW**	**$4.98**	**$4.20**	**$6.08**
8	**NBC Sub-Total**	**$/kWh**	**$0.02243**	**$0.01930**	$0.02135
9	**Total Converted to a Pure $ per kW Basis**	**$/kW**	**$6.14**	**$5.76**	**$7.66**

Lines 1-6 display Cal Advocates' GBC components, while lines 7-8 provide sub-totals to show the overall size of the GBC. Similarly, line 9 converts all GBC components to a pure dollar per kW of system capacity basis based on a typical customer's on-site consumption of PV generation.[239] Line 9 is provided for informational purposes only to indicate the overall size of the GBC. Cal Advocates' proposed GBC is considerably smaller than the fixed and grid access charges proposed by E3 in the Whitepaper, i.e., the $40 monthly fixed charge and $24.40/kW grid access charge under the Multi-Part Grid rate.[240]

Cal Advocates also proposes non-residential GBCs that would be constructed using only the four NBCs (lines 3-6 in Table 3-6), which should reflect the NBCs that are current at the time the improved successor tariff is implemented.

Cal Advocates also did not set its residential GBCs at full cost basis – which would have required including customers' total cost of service in the GBC calculations including generation costs as well distribution and transmission costs. Rather, Cal Advocates designed the GBCs to recover only a portion of successor tariff customers' cost of service shortfall to mitigate bill impacts to customers of the improved successor tariff.

[239] It uses the NEM 2.0 residential class-average annual on-site consumption percentages of each IOU. See Cal Advocates PG&E, SCE, and SDG&E GBC workpapers.

[240] E3 and Verdant, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," p. 24.

1. The Improved Successor Tariff Should Include GBC to Ensure Equitable, Cost-Based Recovery of the Cost to Serve NEM customers.

i. Equal Percent of Marginal Cost (EPMC)-scaled marginal costs form the basis of cost of service and of fair, equitable rates.

A well designed and equitable rate design would ensure that all pay their cost of service to ensure a just and reasonable allocation of the utility's costs among all customers. Cost of service is the total costs to the system of providing electrical service to a group of customers. Beginning in the late 1970's, the Commission adopted a marginal costs-based approach to revenue allocation (cost of service) and ratesetting.[241] Under a marginal costs-based approach to cost of service, the Commission determines customer groups' cost of service by calculating the theoretical marginal costs their usage imposes on the system. Using marginal costs to determine cost of service promotes economic efficiency because it simulates what pricing would be under a competitive market. It also assigns the largest costs responsibility (cost of service) to those customer groups that impose the highest additional costs.[242] This creates an incentive for customer classes to avoid imposing additional costs on the utility and theoretically keeps rates as low as possible for all classes.[243]

However, because total marginal costs rarely match the utility's revenue requirement, the Commission assigns the system's total system costs above marginal costs – what Cal Advocates refers to herein as the system's fixed costs – among customer groups using the equal percent of marginal cost (EPMC) approach. EPMC means the Commission scales all customer groups' marginal costs by the same EPMC multipliers[244] so that total system marginal costs equals the Commission-approved revenue requirement.[245] Because the EPMC approach assigns the system's fixed costs to all customer groups in proportion to the incremental costs their usage imposes on the utility, the Commission has repeatedly found the EPMC approach to be a fair,

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[241] D.18-08-013, p. 12.

[242] D.18-08-013, p. 15.

[243] D.18-08-013, p. 15.

[244] Each utility has a single EPMC multiplier applied to all marginal distribution costs and a single EPMC multiplier applied to all marginal generation costs.

[245] The Commission has employed a marginal costs approach to revenue allocation using the EPMC approach since the early 1980's. D.18-08-013 pp. 13-15 and p. 17 citing D.89-12-057, p. 220.

equitable way to assign the revenue requirement (system marginal and fixed costs) among customer groups.[246]

In addition to approving EPMC-scaled marginal costs as the basis for revenue allocation, the Commission typically uses EPMC-scaled marginal costs as the starting point for assigning cost responsibility among individual customers *within* customer classes.[247] This prevents intra-class shifting of revenues and costs, which can produce inequities in customers' total costs responsibility and in their rates. Thus, the Commission considers rates that recover full EPMC scaled marginal costs as cost-based and as being the "preferred way to achieve fair, equitable rates."[248]

ii. Successor tariff customers benefit from an adequately maintained, safe, and reliable distribution and transmission system and should pay their share of fixed costs like all other customers

All customers should pay for the essential services included in fixed costs, because all customers benefit from the services covered by those costs. The Whitepaper states that "meeting the directives of [Assembly Bill] 327 requires a rate mechanism that precludes the shifting of non-avoidable, fixed costs of serving customer-generators to nonparticipating customers."[249] In the Whitepaper, the term fixed costs or unavoidable cost of service refers to all the utility's costs of providing electrical service that are not time-varying marginal costs.[250] These include marginal customer access costs, non-time varying marginal distribution capacity costs,[251] and total system costs above marginal costs or EPMC-scaled costs.

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[246] D.18-08-013, p. 14, p. 15 citing D.82-12-113 p. 131, p. 16 citing D.86-08-083 p. 26 and D.87-05-071, COL 3.

[247] D.18-08-013, pp. 17-18.

[248] D.18-08-013, p. 16 citing D.86-08-083 p. 26, p. 19 citing D.87-12-033 p. 2 citing D.86-08-083 p. 62, COL 26-27.

[249] The Whitepaper, p. 8.

[250] The Whitepaper makes it clear that in all three of its alternative proposals, the goal is to reduce the volumetric rates as close as possible to marginal/avoided costs and to recover all the remaining unavoidable or fixed costs of service through some combination of demand, fixed, and grid access charges. The Whitepaper, pp. 20, 23.

[251] Such as the marginal costs of the most localized parts of the distribution system, which the utilities typically allocate among customer classes using some measure of customers' demand (kW).

Marginal customer access costs and marginal distribution demand-driven costs are not strictly fixed costs, however, because they vary with the number of customers and with customers' demand profiles. Cal Advocates uses the term fixed costs in this Testimony to refer only to the utility's total system costs that are above marginal costs. Marginal costs represent the changes to system costs that result from an incremental unit of demand.[252] In a highly regulated, capital-intensive industry like the electric power industry, the total costs of the system can differ substantially from marginal costs, and in recent years the three IOUs' total system costs (revenue requirement) have been significantly larger than total marginal costs.

For instance, distribution system fixed costs include the costs to maintain and replace aging or worn distribution infrastructure, costs to install sophisticated automated monitoring and control systems that enable greater integration of BTM generation, the costs of fire hardening the system and other measures that mitigate the risks of wildfires, and the costs of capital projects that ensure sufficient levels of safe and reliable service to all customers.[253] Even though fixed costs are not marginal costs, they represent equally important functions of the provision of adequate, safe, and reliable electric service. Thus, all customers who use the distribution and transmission systems benefit from fixed costs and should pay their fair share.

iii. NEM 2.0 customers pay 82 to 91% less than their annual cost of service, which unfairly shifts costs onto nonparticipants

NEM customers pay for only a small fraction of their total cost of service after installing on-site generation, which pushes their EPMC costs responsibility onto other customers. NEM customers tend to be larger than average users prior to installing an on-site generator, and even after installing on-site generation, they continue to impose high levels of peak period usage and customer demand (kW) on the system.[254] The NEM 2.0 lookback study reports that average *pre-interconnection* annual consumption for residential NEM 2.0 customers for solar PV mostly generates during the middle of the day, so even after installing on-site generation, these customers continue to impose high peak period usage and customer demand levels (kW) on the

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[252] Demand can refer to the number of customers, coincident and non-coincident demand (kW), load (kWh), and other forms of usage of the electric system.

[253] The costs of maintaining and replacing aging distribution infrastructure are not included in marginal distribution capacity costs, which only include capacity costs associated with incremental load growth.

[254] See Table 3-6 below.

system. This means that they continue to impose large costs on the system, especially in distribution cost of service.[255]

PG&E performed a full marginal costs-based cost of service study for NEM and non-NEM customers in its 2020 GRC Phase 2 proceeding,[256] which allows for a granular, cost-based comparison of individual components of cost of service between NEM and non-NEM customers. Cal Advocates requested that PG&E provide residential customers' average monthly distribution cost of service on a per customer basis using the most recently available customer usage data (2019). The results are presented below:

Table 3-7
Comparison of Average Monthly Distribution Cost of Service per Customer between PG&E Residential NEM and Non-NEM Customers[257]

Rate group	Number of Customer[1]	Average Solar PV System Size (kW)/Customer	Final Line Transformer (FLT) Avg kW/Customer (2017 Data)	Avg Distribution Cost of Service $/Cust-month
NEM	422,863	5.6	5.3	$65.24
Non-NEM	4,242,167		2.9	$43.53

[1] Number of customers is the average of end of year (EOY) 2018 and EOY 2019 and is close to the total customer-months divided by 12.

Residential NEM customers' average monthly cost of service ($65.24 per customer) is 50% higher than average non-NEM monthly cost of service ($43.53 per customer). One reason that NEM customers' cost of service is higher than non-NEM is that their contribution to final line transformer (FLT) loading (5.3 kW) is 83% higher than non-NEM customers' average contribution to FLT maximum loading (2.9 kW). The FLT steps down the voltage from the distribution system levels to voltage levels that can be used by customers. The annual maximum demand (kW) of the FLT drives several costs components of marginal customer access costs

[255] Average annual consumption of a typical residential single-family dwelling is 7,701 kWh, 7,450 kWh, and 7,453 kWh for PG&E, SCE, and SDG&E. Verdant, LLC, "NEM 2.0 Lookback Study," p. 4.

[256] Application (A.) 19-11-019. This process included separating the various usage characteristics (marginal cost drivers) of NEM and Non-NEM customers, separately calculating the various marginal unit costs of each group, and multiplying the marginal costs by their respective marginal cost drivers to derive total marginal costs imposed on the system by NEM and Non-NEM within each customer class.

[257] PG&E A.19-11-019 GRC 2 revenue allocation workpapers, MC-Rev workpaper.

(described below), and it drives the costs of the secondary voltage (less than 4 kV) portion of PG&E's distribution system, which includes the most localized distribution lines and other infrastructure that are upstream of the FLTs.[258] NEM customers tend to place higher loading on FLTs and secondary voltage distribution infrastructure because they are larger (higher demand) customers than non-NEM, and most residential FLTs peak in the evening when there is little PV generation.[259] Finally, NEM customers likely have higher distribution marginal customer access costs (MCAC) than non-NEM, because NEM customers often require more complex billing system arrangements and higher customer service costs.[260]

In addition, SCE and SDG&E provided various measures of distribution system usage by residential NEM and non-NEM customers that paint a similar picture that NEM customers impose higher costs on the distribution system than non-NEM customers:

Table 3-8
Comparison of Various Usage Characteristics
of Average Residential NEM and Non-NEM Customers[261]

	Non-NEM	**NEM**	**% Difference**
SCE Summer Monthly Peak Demand (kW)	4.3	6.31	47%
SCE Summer Monthly Mid-Peak Demand (kW)	3.99	5.9	48%
SCE Monthly Non-Coincident Demand (kW)	4.11	5.72	39%
SDG&E – Coincident Demand (kW)	5.03	5.66	13%
SDG&E – Non-Coincident Demand (kW)	4.18	6.06	45%

[258] PG&E uses FLT loading to assign 50.5% of residential class' total marginal distribution capacity costs revenue responsibility in its 2020 GRC Phase 2, while it assigns 49.5% based on residential customers' volumetric usage (kWh) across hours of highest capacity risk of the distribution substations and circuits that serve them. The distribution cost of service estimates in Table 3-7 also includes the effect of customers' contribution to substation/circuit risk hours, but PG&E was not able to separate the substation/circuit usage factors on an average per customer basis. Derived from A.19-11-019, Exh. PG&E-02, PG&E Cost of Service Testimony, p. 8-18, Table 8-5.

[259] See Figure 3-2 below.

[260] MCAC represent the marginal costs of providing a customer connection to the grid, including the equipment costs the transformer, service line drop, meter, ongoing equipment operations and maintenance, and customer service costs related to billing and customer call centers.

[261] Derived from Cal Advocates-SCE DR 07 Q01 and Cal Advocates-SDGE DR 04Corrected Q01 (provided in response to Cal Advocates-SDGE DR 08).

Residential NEM customers' coincident and non-coincident demand are generally 13 to 48% higher than non-NEM customers' demand across all measures of demand. Although SCE and SDG&E have not performed a full cost of service analysis for NEM and non-NEM customers, this data provides strong evidence that the distribution cost of service of NEM customers is likely to be significantly higher than for non-NEM customers for SCE and SDG&E as the underlying physics of transmitting electric energy remains the same.

Finally, Verdant performed a full cost of service analysis for residential NEM 2.0 customers in the NEM 2.0 lookback study that showed large shortfalls in NEM 2.0 customers' annual bills from their cost of service responsibility for all three IOUs. Verdant's cost of service analysis includes all components of the CPUC's revenue allocation (cost of service) process.[262] The results of its analysis for residential NEM 2.0 customers are presented below:

Table 3-9
Results of NEM 2.0 Lookback Study Cost of Service Analysis Comparing Residential NEM 2.0 Customers' Annual Bills to their Annual Cost of Service[263]

	PGE	SCE	SDGE
	Post-NEM Bill Payment/ Cost of Service	**Post-NEM Bill Payment/ Cost of Service**	**Post-NEM Bill Payment/ Cost of Service**
Residential	18%	9%	9%

The table above compares a typical NEM 2.0 customer's annual bills to cost of service. Verdant performed the cost of service analysis based on their aggregate post-interconnection consumption profile – that is, accounting for changes in metered consumption due to on-site generation and any changes to gross consumption following interconnection of the PV system.[264]

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[262] Verdant's analysis includes total marginal costs, regulatory costs (EPMC or fixed costs plus non-bypassable charges), transmission costs, and costs that are unique to NEM customers such as interconnection and NEM-specific billing costs. If NEM customers were treated as a separate class, their interconnection and more complex billing and customer service costs could be included in their marginal customer access costs. Verdant, LLC, "NEM 2.0 Lookback Study," p. ix (Glossary).

[263] Verdant, "NEM 2.0 Lookback Study," p. 98.

[264] The Lookback Study found that NEM 2.0 customers typically increase their gross consumption after interconnecting their PV system. Verdant, "NEM 2.0 Lookback Study," pp. 30, 98.

Verdant found that NEM customers underpay their cost of service by large margins.[265] SCE and SDG&E customers paid only 9% of their cost of service while PG&E customers paid only 18% of their cost of service.[266] These are very large shortfalls in cost of service that demonstrates that the overwhelming majority of the costs imposed by NEM 2.0 customers on the system are pushed onto other customers. In fact, NEM 2.0 customers' bill payments are so low that they do not even cover their marginal costs of service – meaning both their fixed costs *and* marginal costs responsibilities are pushed onto other customers.

NEM customers' bill savings are much larger than the benefits provided by their on-site generation, because the avoidance of full residential volumetric retail rates compensates NEM customers for many costs that their on-site generation does not avoid. Residential rates are designed with a number of customer considerations in mind, such as balancing the ten residential rate design principles and promoting residential customers' ability to understand and respond to the rates. Therefore, many residential rates are designed to deviate somewhat from full cost basis with fewer rate components and less granularity. For example, the FLT-related costs that comprise approximately 50% of total PG&E residential marginal distribution capacity costs revenues are recovered as a flat volumetric rate ($/kWh) during all hours. Consequently, NEM customers can avoid paying for a large portion of their FLT costs even though the FLTs predominately peak in the evening period when PV generation provides very little benefit to alleviating FLT stress.[267]

As demonstrated in Figure 3-1 in the section on ECR, because TOU periods are defined using many criteria in addition to cost basis, evening PV generation (4-9pm) receives very high compensation (On-Peak retail rates) for generation and distribution capacity value that it does not provide to the system. In addition, the default TOU rates are designed using a "TOU-lite" approach with less time differentiation than if they were designed at full marginal cost basis.[268]

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[265] Verdant, "NEM 2.0 Lookback Study," p. 98.

[266] Verdant, "NEM 2.0 Lookback Study," p. 98.

[267] This is explained in greater detail in Section iv below.

[268] The purpose of this is to allow residential customers' more time to understand and adapt to TOU rates and to limit customer bill impacts of the transition from tiered rates to default TOU rates. For example, see D.19-07-004 which approved default TOU rates for PGE and SCE, page 31.

Thus, NEM customers can receive compensation at artificially high Off-Peak rates, while also paying lower On-Peak costs for consumption.

Since residential rates are designed to recover residential customers' total cost of service while considering various customer considerations, they were not designed to produce accurate compensation at full retail rates for customers who install PV systems. This unfortunately produces the kind of inequitable cost burdens from NEM to non-NEM customers described in Chapter 2. To correct this inequity, the successor tariff should account for the need to balance total benefits of the rate with total costs by sending clear, accurate price signals to customers about the costs their consumption patterns impose on the system. However, simply shifting NEM customers to cost-based TOU rates as discussed earlier in section IV will not solve the cost burden problem. A cost-based GBC, implemented together with exports compensation based on avoided costs, would further reduce the NEM cost burden.

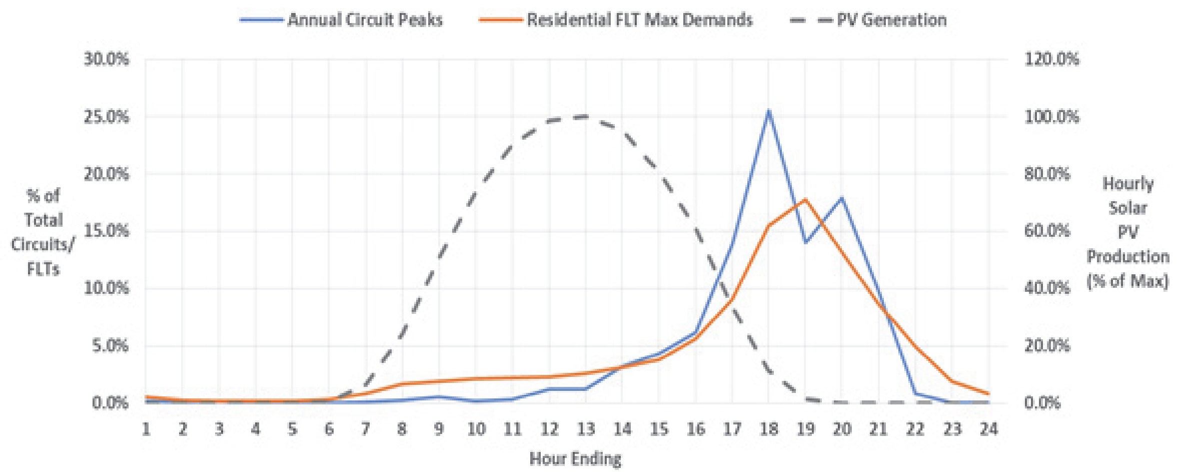
2. NEM customers pay for little of their distribution cost of service because the timing of PV generation does not align with the hours of high distribution system costs.

The large over-compensation of NEM customers' generation relative to the value provided to the system is partly explained by the fact that the timing of PV generation does not align well with the timing of highest costs on the distribution system. BTM PV generation provides very little value to the localized or the more upstream, shared portions[269] of the distribution system. The chart below shows a comparison of the generation of a typical residential PV system to PG&E's residential circuit and FLT peaks.

[269] "Upstream" means these components are relatively farther away from the customer's premise and closer to the transmission system, and it includes those portions of the distribution system that are shared among many customers, such as circuit feeder lines and substations.

The chart compares the average hourly annual production profile of a typical residential BTM PV system[270] (grey dashed line) to the annual peak demands of all PG&E's mixed residential-commercial (RC) circuits and its residential-only (R) FLTs.[271] The PV production curve's peak of the PV production curve occurs between 12-1pm,[272] which is about 4.5-5 hours earlier than the peaks of the circuit (6pm) and FLT (5-6pm) curves.[273] Most PV production occurs early in the day when the occurrence of peak demands on circuits and FLT is very low; solar production falls off rapidly by 3-4pm (hour ending (HE) 16), which is when circuit and FLT peaks begin to rapidly increase. Evidently, PV generation provides little value to the distribution system relative to its total production (kWh) because PV generation is low and declining during the hours of highest distribution system costs.

Figure 3-2. Comparison of Timing of BTM PV Production with Timing of PG&E's Residential-Commercial Annual Circuit Peaks and its Residential FLT Peak Demands



Another way to look at the data is to compare cumulative PV production and cumulative circuit/FLT peaks. The following chart compares inverse cumulative annual PV production,[274]

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[270] The system is a 4 kW system located in San Jose. See workpapers for more details.

[271] RC circuits are the most common circuit type serving residential customers and they serve 45.6% of residential customers, while R FLTs serve 3.538 million or 75.6% of PG&E's 4.68 million residential customers. A.19-11-019, Exh. PG&E, PG&E Cost of Service Rebuttal Testimony, p. 7-Attach-A-2. See Attachments 3-A and 3-B.

[272] The exact value of the mean (highest point) of the PV curve is hour ending (HE) 12.7.

[273] The peaks of the aggregate circuit and FLT annual peak load curves are at HE 18.0 and HE 17.3. The peak is the statistical mean of the distribution curve.

[274] That is, 1 minus annual production occurring up and including hour *i*. This is the same as measuring all production/costs that occur on a daily basis *after hour i* across the year.

or the total amount of annual solar production *occurring after hour i*, to the percentage of total circuit and FLT annual peaks occurring after hour *i*. This analysis clearly captures the total mount of solar generation that is available in the evening hours when many circuits and FLTs peak. See the results in Figure 3-3 below for PG&E.

The dashed grey line represents total solar production that occurs *after hour i* over the course of the year, while the blue curve represents percentage of total circuits that peak after hour *i* and the orange line represents total FLTs that peak after hour *i*. The analysis shows that only 14.9% of annual solar PV production occurs *after* 3pm (HE 15 or vertical yellow line) while 88.1% of all circuit peak demands (blue curve) and 77.6% of FLT peaks occur after 3pm. In addition, only 1.8% of total solar PV production occurs after 5pm (HE 17) while 68% of circuit peak after 5pm.

This same pattern of solar PV production compared to peaks in the distribution system is observed for SCE and SDG&E.

Figure 3-3. Comparison of Cumulative Annual Solar Production Occurring After Hour *i* and Total PG&E RC Circuits and R FLTs Peaking Occurring after Hour *i* (2017)

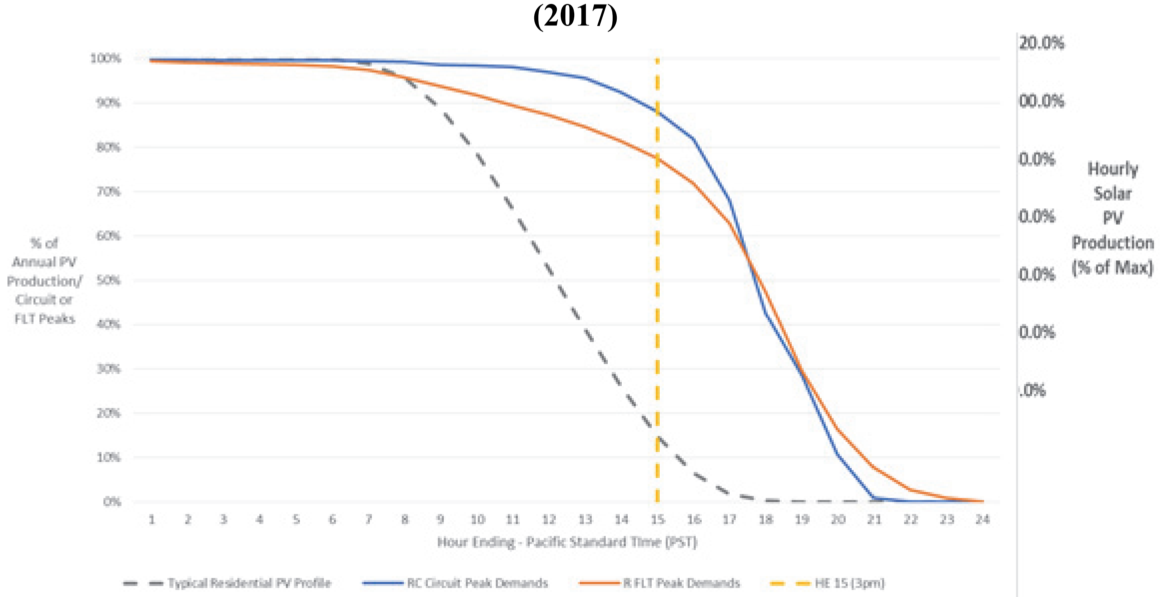
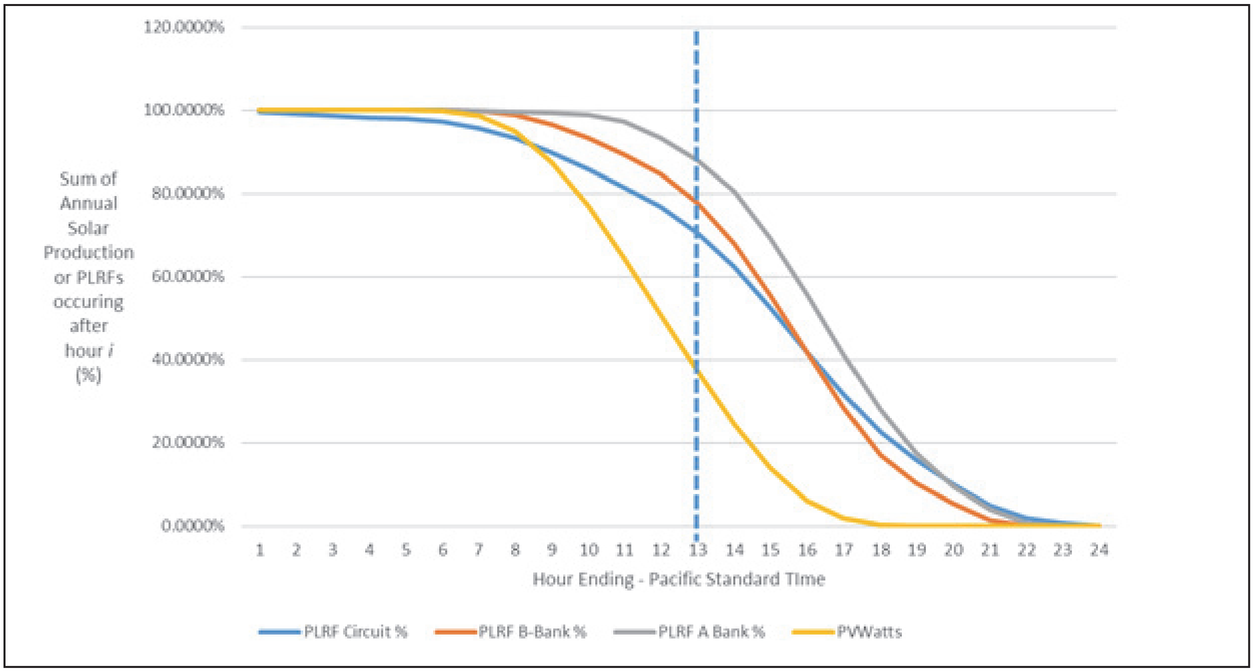


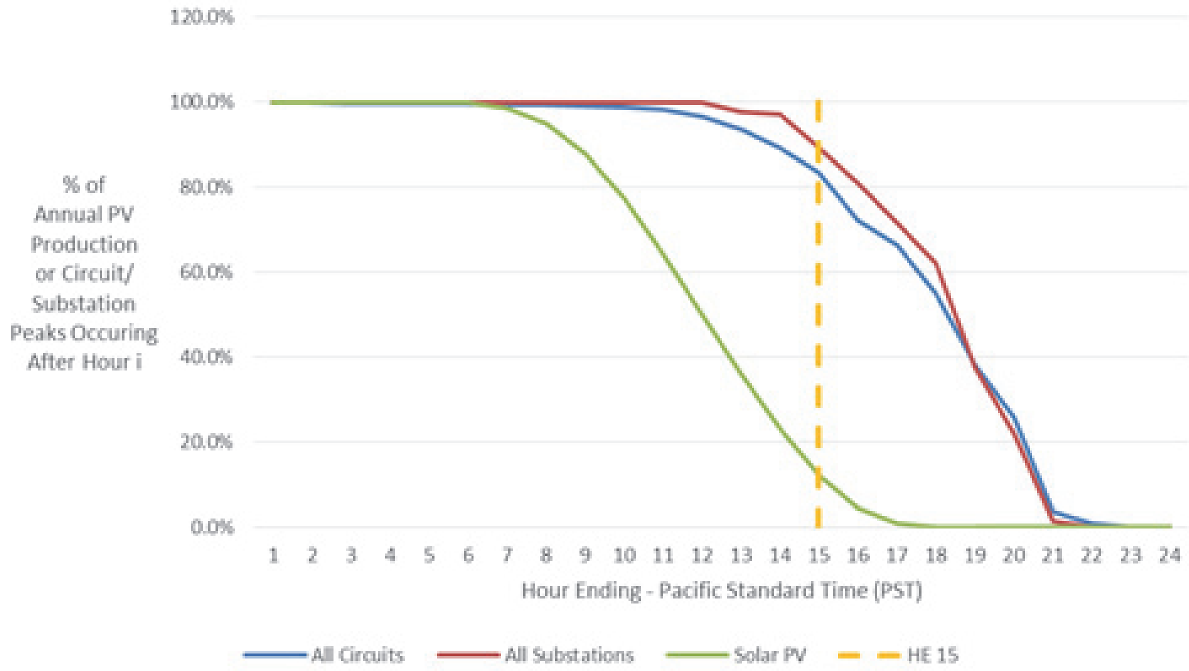
Figure 3-4. SCE Comparison of Annual PV Production Occurring After Hour i and Percentage of Total Distribution Circuit and Substation Peak Load Risk Factors (PLRF)[275] Occurring after Hour i



SCE's distribution assets begin to peak a few hours earlier in the day than PG&E's, as indicated by a general shift of the PLRF curves to the left. However, it is clear from the chart that PV production drops off much more rapidly than the hourly distribution system risks (costs) do. 70.5% of circuit PLRFs occur after hour ending (HE) 13 (1pm), 77.8% of B-bank PLRFs occur after HE 13, and 88% of A-bank PLRFs occur after HE 13, while only 37% of PV production occurs after HE 13 and PV production drops off very rapidly due to the shape of the PV production curve. Finally, the graph below shows a very similar situation for SDG&E as for PG&E.

[275] Peak load risk factors (PLRF) represent the hours in which SCE's distribution system equipment experiences its highest stress (loading) relative to available capacity. They are calculated based on customers' demand during all hours that exceed a pre-defined loading (risk) threshold on each distribution system asset.

Figure 3-5. SDG&E Comparison of Annual PV Production Occurring After Hour i and Percentage of Total &E Substation and Circuit Peaks Occurring after Hour i (2016)



This analysis shows that solar PV provides little value to the distribution system relative to the compensation at full retail rates that NEM customers receive for their reduced on-site consumption. If this problem is not fixed, the addition of new BTM systems such as storage will simply exacerbate the already large distribution cost burden that NEM customers pass on to nonparticipants. Currently, NEM customers do not receive accurate information concerning their distribution cost of service, which could provide valuable information that could encourage them to install technologies that are capable of producing significant distribution system benefits - such as energy storage. Thus, there is a need to send a clear, cost-based price signal that reflects system costs that PV generation does not avoid, which will yield more accurate monthly bills reflecting the total costs that current NEM and successor tariff customers impose on the system. This price signal can be provided most equitably, and in line with the Commission's cost of service principles, through a monthly charge based on the costs of distribution services that a customer receives from the distribution system, or a GBC.

3. The GBC should include NBCs to ensure all customers contribute equitably to programs that have broad societal benefits.

NEM customers are not paying their fair share of NBCs. NBCs include the costs of public programs that serve broad societal purposes and benefit all ratepayers. One example is the costs of the California Alternate Rates for Energy (CARE) program, which are recovered through the Public Purpose Program charge and ensure that all customers have equitable access to electricity at affordable rates by providing low-income Californians with a line-item discount on their electric bills. Other programs include the costs of decommissioning nuclear generators (nuclear Decommissioning charge), and costs of emergency electricity procurements to mitigate widespread outages during the 2001 energy crisis (Department of Water Resources Bond Charges).[276] The provision of on-site generation does not reduce the need or the costs of these programs, nor does it provide any reason to exempt customers from their responsibility to equitably pay for these program costs. Cal Advocates' proposal would ensure that such costs are truly non-bypassable.

Currently, NEM 2.0 customers are required to pay four NBCs based on their metered consumption (kWh) during each billing cycle.[277] These charges include the Public Purpose Program charge, nuclear decommissioning charge, Competition Transition charge and department of water resources bond charges. Under the NEM 2.0 tariff, NEM customers can avoid paying a large portion of their NBCs by choosing to serve some of their gross consumption from an on-site generator, which reduces their metered load. Unlike NEM customers, departing load customers are still required to pay the same amount of NBCs as if they remained bundled customers.[278] Similarly, NEM customers should not be allowed to avoid paying these costs to achieve financial indifference between NEM and non-NEM customers. To achieve true non-bypass, NBCs should be assessed on customers' monthly gross consumption.

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[276] Nuclear generation provides consistent day and nighttime baseload generation for the benefit of all customers, so the NDC is an NBC and is allocated widely across all customers on the basis of sales.

[277] Metered load is equivalent to their Channel 1 meter readings, or all electricity delivered from the utility to the customer's premise. D.160-01-44, p. 89, FoF 41-43.

[278] Both bundled and unbundled customers pay the same delivery rate which include all of the mentioned charges including the power charge indifference adjustment (PCIA).

The current practice of assessing NBCs on metered load for BTM generation customers leads to a highly inequitable outcome where those customers who have the most financial means—such as customers who are homeowners and who have sufficient capital or access to credit to install BTM generation—are able to bypass significant portions of the costs of public programs designed to promote equity and to benefit all ratepayers.[279] There is a cost burden to nonparticipants when NEM customers avoid paying for NBCs, which are re-allocated to nonparticipants. The Commission needs to reform the collection of NBCs to ensure all customers equitably contribute to NBC cost recovery.

In addition to creating inequitable cost recovery of societal programs, the current treatment of NBCs also promotes inefficient economic investment decision-making, because it sends an inaccurate price signal to prospective customers. The current NBC treatment leads prospective DG customers to make investment decisions on the assumption that their generation reduces the total costs of social programs (system-wide NBCs) when in reality the value that their generation provides to the system and society is avoided costs. Avoided costs do not include any NBCs, which are not dependent on customers' incremental usage and are therefore not avoidable in an economic sense. For such costs to be truly non-bypassable, NBCs should be assessed in the GBC based on customers' total gross on-site consumption (kWh) of on-site generation during each billing cycle.

To ensure consistency with the requirement that NBCs be collected on the basis of usage (kWh), the customers should be given two choices to assess the NBCs components of the GBC: installation of a separate, utility-grade meter to track on-site consumption during each billing cycle, or the use of an engineering estimate of total monthly on-site consumption (kWh) of the BTM generation resource.[280] A customer who chooses the first option would be responsible for paying for the permitting and installation costs of the meter, and they would be able to calculate their exact on-site consumption every month. If the customer opts for the latter choice, the

[279] Residential NEM 2.0 customers bypass the portion of their NBC responsibility that is equal to the percentage of their annual production that is consumed on-site. On average NEM 2.0 customers bypass approximately 56% of their total NBC responsibility for SCE, 52% for PG&E, and 35.5% for SDG&E. Cal Advocates' cost burden models for SCE, PGE&, and SDG&E, General Inputs tabs.

[280] The separate meter would measure total generation of the on-site generator during each billing cycle. Netting the customers' Channel 2 meter readings (net exports) from total on-site generation yields total on-site consumption (kWh) during the billing cycle.

engineering estimate should be based on a typical or average annual residential PV production profile scaled to the customer's PV system size ($kW_{CEC\text{-}AC}$) to estimate total annual production (kWh).[281] Monthly on-site consumption would be estimated by taking the total monthly production from the typical PV profile and subtracting the customer's total Channel 2 meter readings (net exports) during the billing cycle. This would provide a reasonable estimate of the customer's monthly on-site consumption (kWh) to create indifference in NBC payments before and after interconnecting their on-site generator.

This NBC proposal is consistent with guiding principle 3 that the successor tariff should promote equity, and it will ensure that non-bypassable charges are truly non-bypassable.[282]

4. Cal Advocates calculated its GBC to recover successor tariff customers' fixed costs responsibility and to prevent unfair cost burdens on other customers

i. Cal Advocates designed its GBC to recover customers' fixed costs responsibility

Cal Advocate designed its GBC to recover the shortfall in customers' cost of service under net billing. The GBC should be assessed as a dollar per kW of installed system capacity charge per month to properly collect the distribution and transmission fixed costs, whereas the NBC components should be assessed based on monthly gross (avoided) on-site consumption (kWh). Specific NBCs including the Public Purpose Program charge, wildfire fund charge, and nuclear decommissioning charges should be recovered based on gross monthly volumetric consumption, consistent with how these costs are statutorily allocated among customer classes.[283]

Cal Advocates proposes a GBC that would ensure that NEM customers pay their appropriate cost of service for distribution and transmission. NEM 2.0 customers have a deficit between 82%-91% on their annual bills compared to their annual cost of service.[284] By setting the ECR under net billing at avoided costs, some of this gap in cost of service would be corrected, but not entirely.

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281 One example is a production profile using the National Renewable Energy Laboratory's PVWatts calculator and using assumptions that are typical of PV installations for the appropriate customer class.

282 D.21-02-007, pp. 13-16, FoF 17, CoL 8, OP 1.

283 D.00-06-034, pp. 4, 93-94, FoF 41, OP 9.

284 Verdant, LLC, "NEM 2.0 Lookback Study," p. 98.

Cal Advocates computed the percentage contribution to cost of service after net billing by multiplying the average annual export ratio attributed to residential NEM 2.0 customers by the customers' annual billing deficit (the shortfall) relative to their cost of service. When net exports are set at avoided cost, the cost burden generated by a NEM customer is reduced by an amount roughly equal to amount of generation the customer exports to the grid. This calculation computes the amount of NEM customers' post-interconnection cost of service that would be recouped under net billing at avoided costs compared to NEM 2.0.

Table 3-10
Recouping Residential NEM 2.0 Customers' Annual Cost of Service under Net Billing at Avoided Costs Only Partially Recovers Their Costs of Service

	(A) NEM 2.0 Annual Bill Deficit as a % of Cost of Service	(B) Average Residential NEM 2.0 Annual Export Percentage[285]	(C)=(A)*(B) Revenues *Recouped* Under Net Billing as a % of Cost of Service
PGE	82%	50%	41%
SCE	91%	44%	40%
SDGE	91%	64%	58.6%

The annual bill savings reduction due to net billing at avoided cost are then added to residential NEM 2.0 customers' annual bills under NEM 2.0 (column A in Table 3-11 below) to compute the customers' average contribution to cost of service under net billing at avoided cost (column C below).

[285] Cal Advocates' cost burden models for PG&E, SCE, and SDG&E, General Inputs tab.

Table 3-11
Calculation of Average PG&E, SCE, and SDG&E Customers' Bill Payments as a Percentage of Cost of Service under Net Billing at Avoided Costs

	(A) Post NEM Bill Payment as % of Cost of Service	(B) Increase in Annual Bill Payments under Net Billing as a % of Cost of Service	(C)=(A)+(B) Post Net Billing Bill Payment as % of Cost of Service	(D) 100%-(C) Percentage of Cost of Service to be collected in GBC
PGE	18%	41%	59%	41%
SCE	9%	40%	49%	51%
SDGE	9%	58.6%	67.6%	32.4%

The GBC is designed to recover the shortfall between 100% of the customer's cost of service and the percentage of their cost of service recovered under net billing (column D). The calculation yields a percentage of total cost of service recovered through the GBC of 41%, 51%, and 32.4% for PG&E, SCE, and SDG&E, respectively.

Finally, Cal Advocates calculates the distribution and transmission components of the GBC by multiplying the percentages from column D of Table 3-11 by customers' average monthly distribution and transmission cost of service. Ideally, these percentages would be applied to the cost of service of a residential NEM 2.0 customer, because the cost of serving NEM customers is higher than non-NEM customers for a variety of reasons discussed in section B.1.iii. Cal Advocates uses the cost of service of residential NEM customers from PG&E's 2020 GRC Phase 2 to calculate the GBC for PG&E residential customers.[286] Since no cost of service studies specific to NEM customers are available for SCE or SDG&E, Cal Advocates uses the residential class average cost of service to calculate the SCE and SDG&E GBCs. Therefore, Cal Advocates' GBC estimates for SCE and SDG&E are conservative because the distribution cost of service per NEM customer is likely higher than the average residential customer. The

[286] Monthly average distribution cost of service is 42.6% higher for NEM customers than for the residential class average for PG&E customers. Derived from PGE's A.19-11-019 GRC2 revenue allocation workpapers. See workpaper entitled McRev.

following table illustrates the derivation of the distribution and transmission components of the GBC.

Table 3-12
Calculation of Distribution and Transmission Components of Residential GBC

		(A)	(B)	(C)	A*B/C
IOU	Component	Cost of Service ($/Cust/Month)	Amount to be collected in GBC	Average Solar PV Size (kW)[287]	GBC ($/kW PV/Month)
PG&E	Distribution	$70.56	41%	6.11	$4.73
	Transmission	$20.04	41%	6.11	$1.34
SCE	Distribution	$38.36	51%	5.59	$3.48
	Transmission	$7.94	51%	5.59	$0.72
SDGE	Distribution	$58.74	32.4%	5.60	$3.40
	Transmission	$27.28	32.4%	5.60	$1.58

Cal Advocates' calculation multiplies the relevant average cost of service in 2022 (column A) by the cost of service shortfall identified under net billing (column B) and normalizes the results to the average PV system size (dividing by column C). The resulting total distribution and transmission components (column D) of the GBC are $4..20 per kW for PG&E, $6.08 per kW for SCE, and $4.98 per kW for SDG&E residential customers in 2022.[288] Inclusion of the distribution and transmission components in the GBC is essential for recovery of successor tariff customers' marginal and fixed cost responsibility and to ensure they pay their fair share of system costs to maintain, repair, and replace the distribution and transmission systems, as well as the costs of maintaining adequate system safety and reliability for all customers. As larger numbers of customers electrify more of their transportation and home end-uses to achieve the state's decarbonization goals, it will be increasingly important to the provision of basic services that all customers equitably contribute to maintaining a modern, safe, and reliable grid.

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[287] Average PV size reflects the average system size of NEM 2.0 customers. Derived from DRs Cal Advocates-SCE 02, Cal Advocates-SDG&E 02, and Cal Advocates-PG&E 02.

[288] Cal Advocates' GBC is measured in the system's alternating current (AC)-rated capacity using the California Energy Commission's method for estimating PV capacity.

Finally, the GBC should increase by the same percentage as the change in class average rate each year, and it should be updated at least as frequently as the IOUs' annual consolidated rates filings. This will ensure the GBC increases at the same rate as retail rates and prevent customers' distribution cost burden from increasing proportionally over time due to the rate of increase in volumetric rates outpacing the rate of increase of the GBC - which is important to contain the total costs of the tariff.

ii. Cal Advocates' total GBCs.

Cal Advocates presents its proposed total GBCs, including all distribution, transmission, and NBC components, below. The Commission should adopt Cal Advocates' distribution and transmission components of the GBC provided below (lines 1-2), and it should adopt inclusion of the four NBCs in the GBC and Cal Advocates' method for assessing the NBCs on customer's monthly gross on-site consumption as described in section B.1.v.

Table 3-13
Cal Advocates' Residential GBCs by Cost Component (2022)

	Component:	**Proposed Units**	**SDG&E**	**SCE**	**PG&E**
1	Distribution	$/kW	$3.40	$3.48	$4.73
2	Transmission	$/kW	$1.58	$0.72	$1.34
3	Competition Transition Charge	$/kWh	$0.00095	$0.00067	$0.00119
4	Public Purpose Program*	$/kWh	$0.01553	$0.01308	$0.01341
5	Nuclear Decommissioning	$/kWh	$0.00006	-$0.00053	$0.00048
6	Wildfire Fund Charge[289]	$/kWh	$0.00589	$0.00608	$0.00627
7	**Distribution and Transmission Sub-Total**	**$/kW**	**$4.98**	**$4.20**	**$6.07**
8	**NBC Sub-Total**	**$/kWh**	**$0.02243**	**$0.01930**	**$0.02135**

Lines 1-6 display the various components of the GBC, while lines 7- 8 are sub-totals to aid the reader's comprehension of the total size of the GBC. The distribution and transmission components are assessed on a $ per kW basis to reflect that they recover system fixed costs that are not avoided by customers' solar PV generation. The four NBCs (lines 3-6) are assessed

[289] This charge was formerly the Department of Water Resources Bond-Charge (DWRB-C), but the Commission replaced with the DWRB-C with a newly approved wildfire charge which resulted in no change in customers' rates at that time. The wildfire charge took effect on October 1, 2020. D.20-09-005.

based on monthly gross consumption (kWh) and would vary from to $.01930/kWh (SCE) to $.02243/kWh (SDG&E). The NBCs provided are illustrative, and the tariff should reflect the current NBCs at the time the tariff is implemented.[290]

iii. Non-Residential GBCs

At this time, Cal Advocates does not propose a distribution or transmission component for non-residential NEM customers. Non-residential tariffs collect less revenue via volumetric rates and more revenues via fixed and demand charges, so the cost burden generated per kW is much smaller than for residential. Cal Advocates intends to evaluate the development of a non-residential NEM cost burden in the future and may propose mitigation measures if needed.

Non-residential customers' GBCs should only include the relevant NBCs. NBCs should be assessed based on monthly gross on-site consumption (kWh) and in the same manner as for residential customers – that is, non-residential customers should be given the choice of either installing a separate, revenue-grade meter or using an engineering estimate of their monthly on-site consumption (kWh).[291] Cal Advocates provides an example of the SCE GBCs for non-residential rate groups below.

Table 3-14
Illustrative Example of SCE GBCs for Non-Residential Customers by Rate Group

Component	Units	Small Commercial	Agricultural	M/L C&I
Nuclear Decommissioning	$/kWh	$ (0.00053)	$ (0.00053)	$ (0.00053)
Competition Transition Charge	$/kWh	$ 0.00074	$ 0.00068	$ 0.00069
Public Purpose Program	$/kWh	$ 0.00956	$ 0.00885	$ 0.01027
Wildfire Fund Charge	$/kWh	$ 0.00573	$ 0.00608	$ 0.00608
Total	**$/kWh**	**$ 0.01549**	**$ 0.01508**	**$ 0.01651**

[290] The NBCs below are illustrative and are calculated using the utilities' 1/1/2020 NBCs (PG&E and SDG&E) or 6/1/2020 NBCs (SCE) escalated at a 4% annual escalation rate to 2022 values.

[291] The annual on-site consumption percentages for non-residential customers should be specific to each customer class, because annual on-site consumption percentages vary significantly by customer class. For instance, annual on-site consumption percentages of SCE customers can range from 68.3% for TOU-GS-1 (a small commercial class) to 77.9% on-site consumption for TOU-8-Secondary. Cal Advocates-SCE DR 07 Q 03, 04, 05.

The NBC values are illustrative, and the tariff should use the current NBC rates of each customer class at the time the tariff is implemented.[292] As this example demonstrates, however, total NBCs show little variation, from $0.01508/kWh on average for Agricultural customers to $0.016521/kWh for Medium and Large Commercial and Industrial (M/L C&I) customers. The Commission should adopt inclusion of the four NBCs in the non-residential GBCs, as well as Cal Advocates' method for assessing the NBCs based on gross consumption. The non-residential GBCs are small but would ensure equitable recovery of the costs of beneficial public programs from all customer classes.

Finally, Cal Advocates provides its residential and non-residential GBCs converted entirely to a dollar per kW basis below. These values are provided only for information purposes to aid in understanding the magnitude of the GBCs on a per kW basis for a typical customer of each customer class:

Table 3-15
Comparison of Average Residential and
Non-Residential GBCs Converted Purely to a $ per kW Basis.

Customer Group	Component:	Units	SDG&E	SCE	PG&E
Residential	Distribution	$/kW	$3.40	$3.48	$4.73
	Transmission	$/kW	$1.58	$0.72	$1.34
	Total NBCs	$/kW	$1.15	$1.55	$1.58
	Residential - Total	$/kW	**$6.14**	**$5.76**	**$7.66**
Non-Residential	Total NBCs	$/kW	$1.48	$1.06	$1.45
	Non-Residential - Total	$/kW	**$1.48**	**$1.06**	**$1.45**

In Table 3-15, Cal Advocates has converted the NBC charges into a dollar per kW charge based on NEM customers' average annual total on-site consumption percentage by customer group purely for information purposes. Cal Advocates presents a single capacity-weighted average of the non-residential class' GBCs for simplicity's sake, because the total variation between non-residential customer classes is small. Cal Advocates' proposed GBCs are much smaller than the combined monthly fixed charge ($40/customer) and grid access charge ($24/kW) proposed in the

[292] The NBCs are calculated using SCE's 6/1/2020 rates and escalating at a rate of 4% per year for two years (to 6/1/2022).

Multi-Part Grid rate in the Whitepaper.[293] However, Cal Advocates' proposal would significantly improve the ability of the successor tariff to promote equity and to ensure that customers pay for essential non-marginal cost grid services that they benefit from.

The GBC would reduce the total annual cost burden in 2030 of the successor tariff by $503 million per year in 2021 dollars (14.3%). To promote equity in recovery of system fixed costs, it is essential that the Commission bring the tariff's total costs (cost burden) closer to total benefits and ensure that DER and non-DER customers alike contribute to the maintenance, safety, and reliability of the grid.

iv. Application of the GBC on $ per kW of system capacity basis minimizes harms to customers and is superior to a GBC based on customer demand

The Whitepaper proposes several different ways to recover system fixed costs including various demand charge proposals, all of which would produce adverse impacts to Residential and Small Commercial customers and are inferior to Cal Advocates' GBC proposal.[294] At the February 28, 2021 workshop on the Whitepaper, there was discussion of constructing a grid access charge (GAC) or GBC based on customers' annual maximum non-coincident demand (kW) to ensure that the GBC is technology neutral.[295] However, assessing the GBC based on a customers' annual maximum demand is a particular form of a non-coincident demand charge[296] generally known as a "ratcheted" demand charge.[297] A ratcheted demand charge can be highly punitive to Residential and Small Commercial customers, many of whom are not aware of their level of demand at any given point in time and whose demands can suddenly spike for very brief periods of time, leaving them with large, unexpected bills that can remain high for multiple billing cycles.

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[293] E3 and Verdant, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," p. 24.

[294] The Whitepaper, pp. 23-24.

[295] GAC is another name for the GBC, but Cal Advocates uses the term GBC to clarify that the GBC does not merely charge customers for access to the grid but for the many benefits they derive from an adequately maintained, reliable, and safe distribution and transmission system.

[296] Non-coincident demand charges customers based on their individual maximum demand, regardless of the timing of when the demand occurs (e.g., Peak or Off-Peak).

[297] Such a charge can only remain constant or increase over the course of the calendar year.

The Whitepaper also proposes a Multi-Part Demand rate that consists of a $50 monthly fixed charge, $40/kW summer Peak demand charge, and a $25/kW summer Mid-Peak demand charge.[298] The issue with this rate is that system fixed costs do not vary with coincident (peak or mid-peak) customer demand. This proposal would potentially create a future cost burden for technologies that reduce demand rather than volumetric usage.

The Whitepaper provides the bill impacts of its rate proposals on electrification and BTM solar for SDG&E customers, which are reproduced below.

Table 3-16
Comparison of Whitepaper's Various Rate Proposal on
Monthly Bill Impacts of Building Electrification and BTM Solar[299]

Monthly Bill	Current Residential	Two-Part Marginal Cost	Multi-Part Grid	Multi-Part Demand
Effect of Electrification on Monthly Bill	$69	$14	$29	-$8
Solar Monthly Bill Savings	-$128	-$27	-$29	-$1

Under SDG&E's current TOU-DR-1 residential rates, a mid-sized inland all-electric home would have a monthly bill that is $69 per month higher than a mid-sized inland dual fuel home (not including reductions to the natural gas bill).[300] Under the Multi-Part Demand rate, after electrifying their home the customer's bill would be $8 per month lower than their electric bill when their home was dual fuel. E3 explains the difference by saying the customer's more efficient air conditioning reduces their Peak load while most of the increased load for heating occurs in the Mid- and Off-Peak periods.[301] While it is possible the monthly bill reduction is a reflection of TOU rates, it is more likely that recovering such large amounts of fixed costs through demand charges would create a situation where the customers' "cost savings" (avoidance of fixed costs) outweighs the marginal costs (TOU) price signals. Either way, under

[298] E3 and Verdant, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," p. 24.

[299] This is a reproduction of Table 7 of the Whitepaper, p. 26.

[300] E3 and Verdant, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," p. 26.

[301] E3 and Verdant, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," p. 26.

the Multi-Part Demand Rate the customer does not pay for the marginal costs of the new electrification load they are adding, which violates the Commission's rate design principle that rates should be based on marginal costs and should encourage economically efficient decision-making,[302] and would create a new cost burden of electrification to nonparticipants.[303] In addition, demand charges create a situation in which customers with poorer demand factors experience higher average rates ($/kWh). This could mean, for instance, that customers who live in inland areas and have peakier load shapes due to summer cooling could pay significantly higher average rates, creating geographical barriers to DER adoption. In short, demand-based charges could harm Residential customers in various ways and should be rejected.

v. Cal Advocates' proposed GBC would support beneficial electrification

Cal Advocates' GBC proposal would support beneficial electrification because the GBC would not increase with incremental usage, with the exception of the NBCs. The GBC has no demand-based charges, so it would not interfere with the TOU rates that are the price signal that modifies customers' charging behavior in the electrification rates. Cal Advocates' GBC is similar to a monthly fixed charge that is scaled to a customer's annual usage, but it does not increase with increased monthly consumption – except for the NBCs components.[304] This means that if a customer later adds beneficial load that consumes electricity from the PV system, such as an EV, the incremental load would *not* result in any increased monthly transmission and distribution (T&D) GBC charges. Rather, the marginal cost of an additional kWh *to the customer* is the opportunity cost of exporting that kWh to the grid (avoided costs) plus NBCs.[305] This is both an economically efficient and equitable outcome, in which the customer pays only

[302] D.15-07-001 p. 28.

[303] In addition, the bill savings of the PV system under the Multi-Part Demand rate are reduced to $1 savings per month, which certainly does not reflect the PV generation's avoided costs value.

[304] This is because customers size their PV systems to serve a certain portion of their annual usage. Every customer will size their system differently to serve their consumption needs, but in general smaller customers will install smaller PV systems and larger customers will install larger systems. Thus, the GBC would likely not have the same harmful impacts on small users as a traditional monthly fixed charge.

[305] Total NBCs payments in the GBC would increase because the customer's monthly net exports would decrease, so their estimated on-site consumption would increase.

the marginal costs value of their incremental consumption plus the costs of essential public programs that all customers should pay.[306]

vi. Generation costs should be excluded from the GBC

Cal Advocates does not include generation costs in its GBC to mitigate customer bill impacts. The Lookback Study cost of service analysis included all components of total cost of service, including generation, distribution, transmission, and regulatory costs.[307] Therefore, to fully recover the residential NEM 2.0 cost of service shortfall identified in the Lookback Study, it would be necessary to use customers' total cost of service as the starting point for the GBC calculations—including generation costs as well as the other cost components listed above. Cal Advocates provides the dollar per kW components GBCs using this approach below:

[306] Here, marginal costs value is used to refer to the *opposite* of avoided costs – that is, the increased costs to the system and society as measured using the 2021 ACC.

[307] Regulatory costs include non-marginal and non-transmission costs such as the EPMC multipliers and non-bypassable charges.

Table 3-17
Calculation of Residential GBCs including Generation, Distribution, and Transmission Costs

		(A)	(B)	(C)	(D) A*B/C
IOU	Cost Component	Cost of Service $/Cust/Month (2022)[308]	Percentage of Cost of Service to be collected in GBC	Average Solar PV Size	GBC Charge $/kW PV/Month (2022)
PGE[309]	Distribution	$70.06	41%	6.11	$4.73
	Generation	$75.60	41%	6.11	$5.07
	Transmission	$20.04	41%	6.11	$1.34
	Total				**$11.15**
SCE	Distribution	$38.36	49%	5.59	$3.48
	Generation	$53.89	49%	5.59	$4.89
	Transmission	$7.94	49%	5.59	$0.72
	Total				**$9.09**
SDG&E	Distribution	$58.74	32.4%	5.60	$3.40
	Generation	$43.88	32.4%	5.60	$2.54
	Transmission	$27.28	32.4%	5.60	$1.58
	Total				**$7.52**

Total generation, distribution, and transmission components of the GBC are $11.15 per kW of system capacity for PG&E, $9.09 per kW for SCE, and $7.52 for SDG&E.

Cal Advocates, however, tempered its GBC proposal below full cost basis to mitigate customer bill impacts. Cal Advocates' proposal results in reasonable payback periods of between 7.8 and 12.2 years.[310] Cal Advocates proposal strikes a reasonable balance between equitably recovery of system fixed costs and non-bypassable Public Purpose Program costs from

[308] All cost of service estimates were escalated at the increase in retail rates (4% per year) consistent with Cal Advocates' proposal that the GBC should increase annually at the same pace as the residential average rate so that the cost burden reductions keep pace with increases to the cost burden over time (driven by increases to retail rates).

[309] This is in 2022 nominal dollars. The GBC should be converted to 2020 nominal in the PGE cost burden model Cal Advocates provided to parties via data request. In 2021 dollars, the total GBC comes out as 4.66/kW when including all proposed costs i.e., distribution, transmission, and NBCs.

[310] See Section VII below on payback periods.

successor tariff customers while mitigating rate impacts. Therefore, the Commission should adopt Cal Advocates' proposed GBCs, which do not include any generation charges.

vii. Low income customers should be exempted from paying the GBC in order to achieve parity in system compensation

California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) (low income) customers should be exempted from paying the GBC to address one of the historical barriers to lower income customers' access to BTM generation. NEM CARE and FERA customers have had lower internal rates of return on their solar PV investments because NEM compensation for these customers is tied to retail rates discounted by the CARE and FERA discount.

Exempting CARE/FERA customers from paying the GBC would increase their annual bill savings by $91.92 per kW of interconnected PV capacity for PG&E customers, $69.12 per kW per year for SCE customers, and $73.68 per kW per year for SDG&E customers in the first year the successor tariff is implemented (2022). Low income customers' bill savings relative to non-CARE would increase over time as the GBCs increases at the same annual rate as retail rates while CARE/FERA customers would remain exempt from these charges, which would produce greater parity in low income and non-CARE customers' system compensation over time. Table 3-18 shows a comparison of CARE and non-CARE customers' annual compensation (annual bill savings) per kW under the NEM 2.0 tariff and Cal Advocates' proposed successor tariff averaged over the years 2022-2030.

Table 3-18
Comparison of Average Annual Bill Savings per kW of CARE and Non-CARE Customers under NEM 2.0 (2022-2030) ($2021)

Rate Schedule	Non-CARE ($ per kW-yr)	CARE ($ per kW-yr)	Difference CARE from Non-CARE ($ per kW-yr.)	Difference CARE from Non-CARE (%)
PG&E E-TOU-C	$516	$334	-$182	-35.3%
SCE-TOU-D-4-9	$450	$311	-$140	-31.0%
SDG&E TOU-DR-1	$511	$350	-$161	-31.5%

CARE customers' average annual compensation is $140 to $182 per kW less than non-CARE customers' compensation under the NEM 2.0 tariff. The table below shows the same results under Cal Advocates' proposal for the improved successor tariff:

Table 3-19
Comparison of Average 2022-2030 Annual Bill Savings per kW of CARE and Non-CARE Customers under Cal Advocates' Proposed Successor Tariff ($2021)[311]

Exports Scenario: Annual Exports Percentage	Rate Schedule	Non-CARE $ per kW-yr	CARE $ per kW-yr	Difference CARE from Non-CARE $ per kW-yr	Difference CARE from Non-CARE %
High - 51.5%	PG&E E-TOU-C	$203	$209	+$6	+3.0%
High - 46.5%	SCE TOU-D-4-9	$231	$228	-$3	-1.2%
High - 51.5%[312]	SDG&E TOU-DR-1	$214	$211	-$3	-1.5%
Low - 32.5%	PG&E E-TOU-C	$289	$258	-$31	-10.7%
Low - 25.0%	SCE TOU-D-4-9	$305	$271	-$35	-11.4%
Low - 26.2%	SDG&E TOU-DR-1	$333	$286	-$47	-14.2%

Cal Advocates provides customers' average annual compensation using a range of estimates of the percentage of a customer's total generation that is exported to the grid (annual exports percentage) to simulate that customers exhibit a wide range of export percentages and that under the successor tariff customers will have a financial incentive to size their systems to avoid

[311] The average annual bill savings are calculated by dividing successor tariff customers' total aggregate annual bill savings over the period 2022-2030 by the sum of annual interconnected capacity (kW) over 2022-2030. Thus, it is a capacity-weighted average that is weighted by total forecasted interconnected capacity (kW) in each year. Cal Advocates assumes average annual increase of retail rates of 4% per year. Cal Advocates SCE, PG&E, and SDG&E cost burden models, Summary tab.

[312] Cal Advocates set the high exports scenario for SDG&E equal to the high scenario for PG&E to simulate that under net billing with ECR at avoided costs, SDG&E customers' exports compensation would decrease by the largest amount among the three IOUs. There it is not likely that new SDG&E customers would continue to size their systems to export 60.3% of their annual generation to the grid. See Section VII below for more details.

exporting energy and maximize annual on-site consumption of their system's generation. [313] Under Cal Advocates' proposal, CARE customers' average annual compensation ranges from $47 less than non-CARE (SDG&E low exports[314]) to $6 per kW greater than non-CARE (PG&E low exports). CARE customers' annual compensation per kW can be higher than non-CARE under Cal Advocates' proposal, because CARE customers are exempt from paying the GBC and they receive the same exports compensation as non-CARE, so their relative compensation to non-CARE customers depends on what proportions of their total annual production they consume on-site or export to the grid. Successor tariff customers are likely to size their systems in such a way as to maximize self-consumption to increase their annual compensation per kW (low exports scenario), although the low exports scenario provides a lower bound estimate and in reality, most customers' exports will likely fall somewhere in between the upper and lower bounds.

Overall, Cal Advocates' proposal would greatly reduce the differences in annual compensation per kW between CARE and non-CARE customers under the NEM 2.0 tariff of -$140 to -$182 per kW per year (comparing CARE customers' compensation relative to non-CARE) to -$47 to +$6 per kW under Cal Advocates' proposed successor tariff. In addition, bill savings per kW among FERA customers would be significantly higher than for CARE customers, because the FERA discount to retail rates (18%) is smaller than the CARE discounts.[315] Cal Advocates' GBC proposal would greatly reduce the structural disparity and bring greater alignment in payback periods between low income and non-low income customers, although it would not produce full parity in payback periods. Cal Advocates' proposed grid

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[313] Cal Advocates models the high exports scenario using *residential current average NEM 2.0* annual export percentages, and it uses the NEM 2.0 average export percentages minus one standard deviation as the lower bound (low exports scenario). Customer's compensation under a net billing structure (the successor tariff) varies considerably depending on the percentage of their total annual generation that is exported to the grid and the percentage that is consumed on-site. Customers will receive significantly higher compensation for their PV generation on a per kWh basis if they consume more of their generation on-site. Further details regarding Cal Advocates' assumptions underlying the exports percentages, see Section VII below on payback periods.

[314] This is not a hard lower limit on exports. Customers' annual net exports percentages generally follow a normal distribution that gradually tails off at the lower and higher ends. There will be a small and gradually declining percentage of customers whose annual exports are less than the lower bound estimate.

[315] The current CARE discounts are 34.95%, 32.5, and 35% to all usage for PG&E, SCE, and SDG&E customers. "CARE/FERA Programs," accessed April 19, 2021, at https://www.cpuc.ca.gov/lowincomerates/

equity charge would produce full parity between payback periods of CARE and non-CARE systems and address other structural barriers in access to BTM generation that low income customers face, as is described in section VI below.

VI. RIGHTING INJUSTICES: CREATING FUNDING FOR EQUITY (A. Buchholz)

To create a specific alternative designed for growth among residential customers in disadvantaged communities, as required by statute, the Natural Resources Defense Council (NRDC) has proposed an Equity Charge.[316] NRDC's Equity Charge is a useful framework that could provide meaningful benefits to customers that historically have been under-represented among NEM participants. The Commission should impose an Equity Charge on all residential NEM 1.0 and 2.0 customers beginning upon the effective date of the successor tariff, with exemptions for CARE and Family Electric Rate Assistance (FERA) NEM customers. Customers who take service on the improved successor tariff should be subject to the Equity Charge 10 years after the date of their system interconnection.

The Equity Charge should have two components: The first component should be used to ensure equity in payback periods between CARE and non-CARE customers and should be paid as an up-front subsidy to CARE households to offset their costs of installation. While CARE customers are exempted from the GBCs proposed by Cal Advocates, there is still some disparity in payback periods: CARE customers save $33-76/kw-year less than non-CARE customers so their payback periods are longer.[317] The funds for this up-front subsidy should be collected from NEM 1.0 and 2.0 customers or distribution funds. A modest fee of $0.14 - $0.34/kw per month on NEM 1.0 and 2.0 customers would collect the funds necessary to pay this up-front subsidy for CARE customers (see table 3-20).

[316] NRDC NEM successor tariff proposal, Appendix A.

[317] Cal Advocates internal modeling.

Table 3-20
Calculations for equity charge collections to fund up-front payment for equalizing payback periods between CARE and non-CARE customers.

	PG&E	SCE	SDG&E
Annual per-kW difference in savings between CARE and non-CARE customers[318]	$76.01	$33.62	$35.72
Up-front payment to equalize payback periods, per-kW[319]	$278.24	$303.46	$371.33
Estimated Annual Increase in CARE-customer-owned systems in 2019[320]	6253	1635	1046
Average system size, CARE customer-owned systems[321]	5.77 kW	6.78 kW	4.48 kW
Total cost, assuming 2019 CARE customer adoption rates and installation sizes[322]	$10 million	$3.4 million	$1.7 million
Equity Charge to collect funds from NEM 1.0 and 2.0 Customers, per kw-month[323]	$0.34	$0.18	$0.14

Should the Commission choose note to implement an equity charge, distribution charges could be an alternative method for cost recovery of these incentives because they also apply to NEM 1.0 customers and customers who receive generation services from a third-party

[318] According to Cal Advocates internal modeling.

[319] According to Cal Advocates internal modeling.

[320] The 2019 increase in CARE/NEM customers according to Cal Advocates Data Requests PGE-003, SCE-003, and SDGE-003 was 12,507, 5450, and 2,227, respectively. To exclude third-party owned systems, this table used third-party ownership estimates from Cal Advocates Data Requests PGE-010, SCE-010, and SDGE-010. In 2019, third-party ownership's represented 50%, 70%, and 53% of CARE customer adoption in each IOU territory, respectively.

[321] According to Cal Advocates Data Requests PGE-010, SCE-010, and SDGE-010.

[322] From Cal Advocates Data Requests PGE-003, SCE-003, SDGE-003, PGE-010, SCE-010, and SDGE-010.

[323] Total kW of rooftop PV for non-CARE NEM customers in August 2020 from Cal Advocates Data Requests PGE-003, SCE-003, SDGE-003. PGE: 2.44 million kW. SCE: 1.56 million kW. SDGE: 0.99 million kW.

provider.[324] Distribution charges are driven by "capital additions and ongoing infrastructure modernization and improvements to the distribution system"[325] An alternative method of collections would be to collect these funds from Public Purpose Program charges, but NEM 1.0 customers are currently exempt from these fees.[326] Failure to include NEM 1.0 customers in paying for this program would not redress the inequities in the current NEM tariff.

The second component of the Equity Charge should be used to increase access to the benefits of renewable energy in disadvantaged communities by addressing the barriers to adoption.[327] This component should be initially calibrated to collect, over the next decade, roughly the same amount that CARE customers have paid for NEM subsidies over the last decade.[328] This calibration would result in a collection of at least $200 million per year.[329] This could be achieved with a modest monthly equity fee of $3.15/kW of installed capacity on all NEM 1.0 and 2.0 customers.[330]

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[324] *Community Choice Aggregation En Banc Background Paper*, February 1, 20217, p. 2. See: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/CCABackgroundPaperv2.pdf.

[325] *California Electric and Gas Utility Report: AB 67 Report to the Governor and Legislator,* April 2020, p. 18. See: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf.

[326] *Decision Adopting Successor to the Net Energy Metering Tariff* (D.16-01-044), R.14-07-002 (January 28, 2016), p. 112.

[327] See Pub. Util. Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

[328] The average PG&E, SCE and SDG&E non-NEM CARE customer paid $106, $67, and $128 more on their annual bills in 2019, respectively, due to NEM according to p. 28 of "Designing Electricity Rates for an Equitable Energy Transition." This means that the three million CARE customers without rooftop solar pay approximately $384 million per year to NEM customers, who tend to be far wealthier than the average customer (NEM 2.0 Lookback Study, p. 33). This does not include payments by FERA-eligible customers, so the true amount paid by lower income customers is likely higher.

[329] CARE customers have paid $1.9 billion for NEM tariffs. This assumes that the CARE customer NEM cost was zero in 2010, the cost in 2020 was $384 million, and that the increase in this cost was linear while the number of CARE customers stayed the same (approximately 3.1 million). To collect this amount over the next ten years would require ~$192 million per year. This has been rounded up to account for the fact that there was a cost burden to CARE customers before 2010 and for the fact that this value does not include FERA customers.

[330] According to responses from a data request to the IOUs, there were 4,994,615 kW of non-CARE NEM rooftop solar as of September 2020. A $3.15/kW monthly charge on these installations would generate

In summary, Cal Advocates' recommended Equity Charge is \$3.15/kW plus \$0.14-\$0.34 for a total \$3.29 - \$3.49/kW charge per month.

A. Allocation of Funds from the Equity Charge

The Commission should use the collected funds to equalize payback periods between CARE and non-CARE customers, and to increase access to renewable BTM generation in disadvantaged communities, as is required by statute.[331] While the component of the equity charge to correct for disparities in payback periods will provide marginally better access to solar, residents of DACs face unique barriers that will not be overcome without more targeted alternatives.

Senate Bill 350 commissioned a study to identify these barriers. The study identified the following challenges ("SB 350 Barriers"):[332]

A) Low home ownership rates

B) Complex needs, ownership, and financial arrangements for low-income multifamily housing

C) Insufficient access to capital

D) Building age

E) Remote or underserved communities

The National Renewable Energy Laboratory (NREL) has identified increased up-front incentives as a means to address the issue of insufficient access to capital.[333] Establishing an Equity Charge would provide funding for these upfront incentives to lower income customers.

Prior to imposing the Equity Charge, the Commission should identify the mechanism for targeting these collected funds to directly provide the benefit of increasing solar adoption by lower income customers. Table 3-21 compares the effectiveness of a variety of existing and possible Commission programs at addressing the identified SB 350 barriers. These include the

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\$189 million in funds for the equity fee. Response to Cal Advocated Data Request #DR-03, received November 16, 2020.

[331] See Pub. Util. Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

[332] SB 350 Barriers Study, p. 2.

[333] "The impact of policies and business models on income equity in rooftop solar adoption." O'Shaughnessy et al., 2020. Published in *Nature Energy*.

Community Solar Green Tariff, the Disadvantaged Communities Green Tariff (DAC-GT), the Disadvantaged Communities - Single-family Solar Home (DAC-SASH), the Self-Generation Incentive Program (SGIP) equity budget, and Solar on Multifamily Affordable Housing (SOMAH).

Table 3-21
Clean energy program options for increasing DAC access to distributed renewable energy.

Barrier	DAC-SASH[334]	SGIP Equity Fund[335]	CSGT/DAC-GT	SOMAH
Low home ownership rates	N	Y	Y	Y
Complex needs, ownership, and financial arrangements for low-income multifamily housing	N	Y	Y	Y
Insufficient access to capital	Y	Y	Y	Y
Building age	N	Y	Y	Y
Remote or underserved communities	Y	Y	Y	Y
Total Barriers Addressed (out of 5)	**2**	**5**	**5**	**5**

Table 3-21 demonstrates that there are several existing programs which may increase adoption of distributed renewables in DACs: DAC-GT, Community Solar Green Tariff program, the SGIP Equity Budget, and SOMAH.

As explained below, the programs that are most likely to successfully increase successor tariff adoption in DACs based on the criteria above are DAC-GT and the SGIP Equity Fund.

1. DAC-GT builds mid-size solar arrays in DACs and allows nearby DAC residents to sign up for a portion of the array's generation capacity for a 20% discount on their electrical

[334] DAC-SASH provides no-cost solar to low-income homeowners in DACs.

[335] SGIP provides incentives for BTM storage and other distributed energy systems.

bills. Costs for energy from these arrays are capped,[336] and all benefits from these projects go to CARE customers in DACs.[337]

The IOUs have demonstrated the ability to quickly sign customers on for DAC-GT discounts: PG&E, for example, was ordered[338] to auto-enroll customers into their DAC-GT program using existing qualifying solar capacity until new DAC-GT facilities come online. PG&E automatically enrolled 10,255 customers by the end of 2020.[339] Customers with the highest need can be enrolled automatically.

CARE ratepayer arrearages increased by $324 million between February and December 2020, in large part due to the COVID-19 pandemic.[340] These residents and other CARE and FERA customers can be served by qualifying solar capacity until new facilities come online, quickly bringing the benefits of new distributed renewables to DACs while meeting immediate needs with interim capacity.

2. <u>The SGIP Equity Fund</u> provides incentives for BTM battery storage for qualifying customers. These funds can cover up to 85% of the cost of a residential storage system. There are several eligibility criteria, some of which allow participation by low-income ratepayers outside of DACs:[341] the SGIP equity fund can be accessed by renters in low-income housing.[342] Combined with rooftop solar, storage can be used to maximize the value of BTM generation for low-income customers.

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[336] Resolution E-4999, p. 66: "PG&E, SCE, and SDG&E shall include a cost containment mechanism for the DAC-GT program in their RFO solicitation documents that is 200% of the maximum executed contract price in the previous Renewable Auction Mechanism's as-available peaking category or the previous Green Tariff, whichever is higher."

[337] See: https://www.cpuc.ca.gov/SolarInDACs/.

[338] D.20-07-008, p. 1.

[339] Quarterly Disadvantaged Communities Green Tariff and Semi-Annual Solar Green Tariff Programs Report of PG&E for Period October-December 2020, p. 1.

[340] Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic, Rulemaking 21-02-014, p. 10.

[341] D.19-09-027 qualifies all California Indian Country as DACs for the purposes of the SGIP equity budget. Appendix A, p. A1.

[342] D.19-09-027, p. 17.

The SGIP Equity Budget is currently waitlisted in PG&E and The Center for Sustainable Energy's programs. However, SCE and SoCalGas have available incentives to their customers.[343]

The other program options also could provide some benefits, but also have limitations:

3. SOMAH provides funding for solar on multifamily affordable housing, and also addresses the SB 350 Barriers. SOMAH currently receives up to $100 million per year.[344] After an initial rush of applications the program has spare funding and no waitlists in any of the IOU service territories.[345] It does not need additional funding, because funding is not a limiting factor at this time.

4. The Community Solar Green Tariff program, under which a utility partners with a local nonprofit or governmental organization to sign up CARE and non-CARE DAC residents for a 20% bill discount and subscription to the output of a local mid-size solar array, addresses each of the SB 350 barriers. However, program implementation has been delayed to the point that it is difficult to assess its effectiveness. No projects are online.

5. DAC-SASH could be used to provide up-front incentives to low-income residents of DACs. DAC-SASH, which provides residential solar to CARE homeowners in DACs, currently provides an incentive of $3 per watt and receives $10 million per year in funding.[346] According to the program administrator, the average installation is 3.7 kW and costs $5.14/W, for a total average cost of $19,000 per installation.[347] The program does not increase access for renters, which is a significant drawback.

VII. PAYBACK PERIODS (B. Gutierrez and N. Chau)

Cal Advocates estimates payback periods resulting from Cal Advocates' successor tariff for non-CARE successor tariff customers of approximately 7.8 to 12.2 years, depending on the IOU and the percentage of a customer's total annual generation that they export to the grid

[343] See: https://www.selfgenca.com/home/program_metrics/. Accessed March 1, 2021.

[344] See: https://calsomah.org/about.

[345] See: https://calsomah.org/waitlist. Accessed March 1, 2021.

[346] D.18-06-027 p. A-5.

[347] July 2020 DAC-SASH Semi-Annual Progress report, p. 12.

(annual exports ratio).[348] Payback periods represent the time it takes for a customer to recoup the total installation costs of their PV system through their cumulative total annual bill savings. Cal Advocates calculates its payback periods on a per kW basis owing to the difficulty of predicting PV system sizes and the percentage of customers' annual generation that is exported to the grid (annual exports percentage) under an improved successor tariff (net billing structure plus GBC). These factors would alter the customer economics of distributed PV and favor system design that minimizes the annual exports percentage and maximize the total amount of generation that is consumed on-site (annual consumption percentage).[349]

Cal Advocates calculates annual bill savings per kW using its cost burden models by modeling all successor tariff customers as taking service on the residential default TOU rate, since this would produce the largest annual bill savings under Cal Advocates' successor tariff proposal.[350,351]

In addition, Cal Advocates provides a range of payback periods to account for the range of annual export ratios that may occur under the successor tariff, because annual compensation, and payback periods, under a net billing structure are highly sensitive to customers' annual exports ratios. This sensitivity is attributed to the fact that net exports are compensated at their avoided costs value, which is significantly lower than full retail rate compensation for generation that is consumed on-site. Table 3-22 below demonstrates the difference between residential customers' average annual compensation for exports ($/kWh) and for on-site consumption ($/kWh) under Cal Advocates' proposed successor tariff in 2022:

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[348] Cal Advocates provides a range of payback periods estimates to reflect that there will be a range in customers' annual exports ratio, which has a large effect on customers' annual bill savings – and payback periods - under the successor tariff because exports are compensated at avoided costs while on-site consumption is compensated the full retail rate.

[349] The annual consumption percentage equals 1 minus the annual exports percentage.

[350] The default TOU rate is E-TOU-C for PG&E, TOU-D-4-9 for SCE, and TOU-DR-1 for SDG&E. Successor tariff customers could choose to take service on an electrification rate, but it would result in lower annual bill savings and longer payback periods.

[351] Calculation of total annual bill savings is an essential part of the model's cost burden calculations. The models match the individual rate components (i.e., distribution, generation, etc.) of each TOU rate schedule to an annual BTM PV generation profile. Weights are aggregated by season and by TOU period in order to allow comparison to the TOU retail rates. For exports, the model applies Cal Advocates' ECR by TOU period to all PV exports by TOU. The model also includes the GBC as a monthly $ per kW charge on all PV capacity (the NBCs in the GBC are modeled using class-average annual consumption ratios and converted to a $ per kW basis).

Table 3-22
Comparison of Average Annual Compensation ($/kWh) of PV On-Site Consumption and Net Exports under Cal Advocates' Proposed Successor Tariff (2022)

Compensation	PG&E ($/kWh)	SCE ($/kWh)	SDG&E ($/kWh)
On-Site Consumption	$0.23649	$0.19299	$0.23019
Net Exports	$0.05690	$0.05961	$0.05476

Average compensation for net exports ($0.05476 to $0.05961/kWh) is close to the total benefits (avoided costs) that PV generation provides to the system, as Cal Advocates demonstrated in Section V.A. regarding its proposed ECR.[352] Compensation for on-site consumption takes into account the reduction to average customer compensation from the GBC.[353] Even accounting for the GBC, customer compensation for on-site consumption would be many multiples of the value that PV provides to the system – from 3.2 times[354] as high as avoided costs value for SCE customers to 4.2 times higher[355] for SDG&E customers – as represented by the average exports compensation rates ($.19299- $0.23019/kWh). In addition, compensation for on-site consumption will increase year-over-year at the same pace as retail rates (roughly 4% per year over the past 5 years), whereas compensation for exports will increase at the same rate as avoided costs from the Avoided Costs Calculator. Thus, if a customer wants to maximize the value of their PV system's compensation on a dollar per kWh basis they would seek to minimize the percentage of total annual generation that is exported to the grid and maximize the percentage that is consumed on-site, bringing their average annual compensation of their generation ($/kWh) closer to the on-site consumption compensation rates.

Under NEM 1.0 and 2.0, customers have a financial incentive to oversize their systems relative to what they can consume on-site to increase their annual exports and "net out" their

[352] PG&E average exports compensation is $.01247/kWh higher than PV generation's avoided costs value ($.0468/kWh) and SDG&E exports compensation is $.01503 higher than avoided costs ($.06166), but generally the values in the Net Exports row of Table 3-22 are within a reasonable range of the avoided costs of PV. See Table 3-2 for a detailed comparison of Cal Advocates' proposed export compensation rates to average avoided costs of PV.

[353] Average compensation for on-site consumption is calculated as total annual customer compensation (bill savings) of generation that is consume on-site *net of the sum of monthly GBCs* divided by total annual kWh production that is consumed on-site.

[354] 0.19299/0.05733

[355] 0.23019/0.04936.

total annual consumption.[356] Net billing substantially eliminates this incentive because of the appropriate price differential between compensation of on-site consumption and exports. The sizing and design of customers' systems are complex decision-making processes that take many factors into account, but it is very likely that customers will design their systems to significantly reduce their annual net exports percentages under the successor tariff relative to the current NEM tariffs.[357]

To account for reductions to PV system annual export ratios under the successor tariff and the wide range in customers' annual exports ratios, Cal Advocates calculates a range of annual bill savings and payback periods using the current average residential NEM 2.0 net export ratios as the *upper bound* of annual exports and using the NEM 2.0 average minus one standard deviation as the *lower bound* of annual exports.[358] These values for the three IOUs are provided below:

Table 3-23
Statistics of Residential NEM 2.0 Annual Net Export Ratios by IOU[359]

	Mean - 1 S.D. **(Lower Bound)**	Mean **(Upper Bound)**	Mean +1 S.D.	**Percentage of Customers who Fall Within +/-1 S.D. of Mean**	**Adjusted SDG&E Upper Bound**
PGE	**32.5%**	**51.5%**	70.4%	69%	
SCE	**25.0%**	**46.5%**	67.9%	62.1%	
SDGE	**26.2%**	60.3%	94.5%	97.5%	**51.5%**

As Table 3-23 demonstrates, there is a wide range in customers' annual net exports ratios. The distribution of net exports ratios is generally normally distributed for SCE and PG&E with large standard deviations, such that 69% of PG&E customers' annual exports fall within 32.5%

[356]Netting out means bringing their annual "net" consumption to zero. Netting of usage is an accounting feature under NEM, where the customer gets to roll back their meter at full retail rates based on their exports levels (kWh). However, their exports do not "net" their consumption in any physical sense.

[357] It is not clear what effect would be on average system size. Data from SDG&E relating NEM 1.0 and 2.0 system size to annual net exports reveals that both *smaller* and *larger systems* than average have significant *lower* annual exports ratios (percentages) than average sized systems and would likely benefit relative to the average size under the successor tariff. Customers may also install storage or electrification technologies, which could increase their system size. See Attachment 3-C.

[358] The amount of generation that is consumed on site equals 1 minus the annual net export percentage. So, a lower net export percentage means a higher annual on-site consumption percentage.

[359] Cal Advocates-SCE DR 07 Q03-05, Cal Advocates-SDGE DR 08 Q02-06.

and 70.4% while 62.1% of SCE customers' annual export ratios fall between 25.0% and 67.9%. SDG&E customers have the highest *average* annual net export ratio (60.3%) and the highest standard deviation (34.2% compared to 18.9% for PG&E and 21.4% for SCE) of the three IOUs.[360]

Rather than using a point estimate of the annual exports ratio, which would not represent the wide variability in customers' exports and in their average and total compensation per kW, Cal Advocates provides a range of payback periods estimates using the NEM 2.0 mean minus one standard deviation as the *lower bound* of the exports estimates (which yields the highest compensation and shortest payback periods) and the mean as the *upper bound* (which yields the lowest compensation and longest payback periods). Cal Advocates adjusts the upper bound of SDG&E to PG&E's NEM 2.0 mean (51.5%) to reflect the high likelihood that SDG&E customers' annual net export percentages would decline considerably under Cal Advocates' proposal, because the differential between on-site consumption and net exports compensation is the greatest for SDG&E ($4.7/kWh or 4.7 times difference) among the IOUs.[361]

Cal Advocates inputs the net exports ratios above into its cost burden models to calculate a range of typical payback periods under its successor tariff proposal. E3 provided simple payback period estimates using a single aggregate customer load profile reflecting medium-sized single-family customers in inland climate zones of each IOU from the NEM 2.0 Lookback Study.[362] However, E3 scaled the annual usage of the typical (aggregate) customer load profile to 7,500 kWh for all three IOUs to facilitate ease of comparison across the IOUs and it assumed the customers' PV systems were sized to meet 100% of their annual usage, based on historical

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[360] Although there are various factors that could contribute to the observed values, it is likely that one main factor is that SDG&E has the highest retail rates of the three IOUs and thus it is more lucrative for SDG&E customers to size their systems to produce higher levels of net exports under the NEM 2.0 tariff. In addition, SCE has the lowest residential rates of the three IOUs and it exhibits the lowest average net export percentage (46.5%).

[361] Derived from Table 3-22. The difference from NEM 2.0 average export compensation (retail rate less non-bypassable charges) of $0.2702/kWh is even larger. SDG&E customers currently have the greatest incentive to oversize their systems because SDG&E has the highest retail rates among the three IOUs, but this would not be the case under the successor tariff. SDG&E exports compensation would be the lowest among the three IOUs under Cal Advocates' proposal. Cal Advocates SDG&E cost burden model.

[362] E3 and Verdant, LLC, "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020: A Comparative Analysis," May 28 2021, p. 10.

sizing under the NEM 2.0 tariff.[363] While E3 only modeled simple payback periods – that is, basing the payback period calculations only on the customer's compensation in the first year and assuming compensation is constant for all years after that – the analysis provided payback period estimates in 2023 and 2030 to reflect some changes in customer's compensation under the various party proposal over time. The results of E3's simple payback periods analysis of Cal Advocates' proposal using rates in 2023 and in 2030 are provided below:

Table 3-24
Results of E3's Simple Payback Period Analysis for Residential Non-CARE Customers for Cal Advocates' Successor Tariff Proposal (2023 and 2030)[364]

	PG&E	SCE	SDG&E
Payback Period – 2023 (years)	12.5	16.5	9.1
Payback Period – 2030 (years)	8.7	10.7	5.8

E3's payback results for CARE and Non-CARE customers contain several abnormalities, such as yielding a payback period for SCE non-CARE customers (16.5) that is 81% longer than for SDG&E customers (9.1 years) despite the fact that Cal Advocates' successor tariff proposals for SCE and SDG&E were very similar.[365] In addition, E3's assumption that customers will size their PV systems to meet 100% of annual usage is highly unrealistic under a net billing structure with accurate pricing of exports, as described above. E3's analysis assumes there should be a continuation of historical system sizing under NEM, even though the successor tariff should better reflect cost and benefits of customers' systems and achieve equity for all customers – meaning it should employ an entirely different rate structure than NEM 2.0 that will incent different customer behavior and system design than the NEM tariffs. E3's analysis is also overly simplistic because neither the 2023 analysis nor the 2030 analysis accounts for the increase in

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[363] E3 and Verdant, LLC, "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020: A Comparative Analysis," May 28 2021, p. 11. A simple payback period divides total system costs by annual bill savings in year 1 to derive the number of years to pay off the system's costs, but it does not accurately take into account that customers' bill savings will change from year to year with changes in retail rates.

[364] E3 and Verdant, LLC, "Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020: A Comparative Analysis," May 28 2021, pp. 19

[365] The difference is not justified by the differences in SCE's and SDG&E's retail rates, which do not vary by 81%.

customers' compensation as retail rates continue to increase. Cal Advocates will work with E3 to identify and correct any errors in its calculations regarding Cal Advocates' proposal and will present any corrections to the results as part of rebuttal testimony.

Cal Advocates' payback periods estimates below are more realistic than E3's in that they reflect the wide variability in customers' exports, different system sizing and design under the successor tariff that will increase customer's on-site consumption of their generation, and the year-over-year increases in customers' annual compensation that will occur as retail rates continue to rise. Cal Advocates uses total PV system installation costs based on the median 2018 installation price of PV systems in California of $3,800 per kW from Lawrence Berkeley National Laboratory's "Tracking the Sun" report.[366] Cal Advocates also applies the 26% federal solar investment tax credit. However, in its 2020 Annual Technology Baseline report the NREL calculates "Moderate" case total PV system installation costs of $2,644 per kW (total capital expenditures) and $19.83/kW-yr. of operating expenditures.[367] These are the PV installation costs used by E3 in its discussion of successor tariff payback periods and in its calculations of the average SDG&E NEM 2.0 payback period in the Whitepaper.[368] Cal Advocates' estimated payback periods use the $3,800 per kW system costs from LNBL and its estimated payback periods are therefore conservative, but Cal Advocates also provides a range of payback periods using PV system costs from NREL's 2020 Annual Technology Baseline for comparative purposes below.

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[366] https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf see slide 21.

[367] These are the total capital expenditures (CapEx) and operating expenditures (OpEx) of installing a residential PV system. These figures do not include the effect of the federal investment tax credit (ITC), so the ITC should be deducted from the system's installation costs to account for the effect of the ITC on system payback periods. 4/5/2021 e-mail correspondence with E3.

[368] The Whitepaper, p. 25.

Table 3-25
Range of Payback Periods for Residential Non-CARE Customers under Cal Advocates' Successor Tariff Proposal[369] [370]

	PG&E		SCE		SDG&E	
	Lower Estimate	Upper Estimate	Lower Estimate	Upper Estimate	Lower Estimate	Upper Estimate
Payback Period with no Grid Equity Charge (Years)	**8.8**	**12.2**	**8.8**	**11.4**	**7.8**	**11.7**
Payback Period with Grid Equity Charge (Years)	**10.0**	**14.6**	**9.8**	**13.2**	**8.6**	**13.8**

The first row shows the payback periods of non-CARE customers under Cal Advocates' proposal for ECR set at TOU-based avoided costs and including the GBC but not including a grid equity charge. The second row shows the payback periods with the inclusion of a grid equity charge.[371] Under Cal Advocates' proposal, the grid equity charge would be applied to customer bills after they have been interconnected for 10 years, so the impact on payback periods would be small. However, the second row of Table 3-25 shows the resulting payback periods *if the grid equity charge was applied to customers' bills beginning in the first year following interconnection* to show the resulting effect on the systems' payback periods.

Cal Advocates' proposal (row 1) would produce payback periods ranging from 7.8 to 12.2 years depending on how much of a customer's annual generation they self-consume, while implementing a grid equity charge in the first year following interconnection would produce payback periods ranging from 8.6 to 14.6 years. Either proposal would yield shorter payback

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[369] Assumes a PV system installed in 2022, 4% annual rate escalation and straight-line escalation of ECR between 2022 and 2030 using the 2022 and 2030 avoided costs resulting from the 2021 ACC. Uses residential "Base case" installation costs of $3.80/Watt plus a 26% reduction due to the investment tax credit (ITC). Lawrence Berkeley National Laboratory's 2019 Tracking the Sun report as cited by Verdant in the Net Energy Metering 2.0 Lookback Study, p. 72.

[370] The upper payback period estimates uses the upper bound annual export percentages while the lower bound estimates use the lower bound export percentages.

[371] The grid equity charge is a system capacity fee that is applied to non-CARE/non-FERA customers and the total grid equity charge is $3.49 per kW for PG&E, $3.33 per kW for SCE, and $3.29 per kW for SDG&E. See Section VI above for further details on the grid equity charge.

periods than shown in Table 3-25 above for customers who size their systems to mostly serve their on-site consumption (lower estimates).

Finally, the range of payback periods using NREL's PV system installation costs are presented below:

Table 3-26
Range of Payback Periods using NREL's 2020 Annual Technology Baseline PV Installation Costs under Cal Advocates' Proposal

	PG&E		SCE		SDG&E	
	Lower Estimate	Upper Estimate	Lower Estimate	Upper Estimate	Lower Estimate	Upper Estimate
Payback Period with no Grid Equity Charge (Years)	**6.6**	**9.2**	**6.7**	**8.8**	**5.9**	**8.8**
Payback Period with Grid Equity Charge (Years)	**7.6**	**11.1**	**7.5**	**10.3**	**6.5**	**10.4**

The payback periods are shorter using NREL's PV installation costs estimates and would range from 5.9 to 9.2 years with no grid equity charge or 6.5 to 11.1 years if the grid equity charge is implemented in the first year following interconnection. Table 3-26 demonstrates that Cal Advocates' proposal would also produce reasonable payback periods using other, well-established estimates of total PV system installation costs.

VIII. CONCLUSION

The successor tariff should be based on net billing with all net exports compensated at avoided costs to bring customer compensation more in alignment with the value their generation provides to the electrical system. Customers should have a choice of rates among a menu of TOU rate options to allow customers to choose the tariff that best fits their types of technology, consumption profile, and ability to respond to TOU rates. The export compensation rates should be set at PV-weighted avoided costs during mid-day TOU periods and at simple average avoided costs during the evening TOU periods to bring total exports compensation in alignment with PV generation's benefits (avoided costs) while promoting technologies that can provide high capacity and avoided-GHG emissions value during the system peak.

The successor tariff should include a GBC to ensure the rates fairly and equitably recover customers' distribution, transmission, and NBC cost responsibility. Finally, the successor tariff should also include a grid equity charge to address the obstacle to adoption among low income customers of high up-front installation costs and promote more equitable access to solar PV among low income customers.

Taken together, Cal Advocates' successor tariff proposal would bring total costs of the successor tariff into better alignment with total benefits and promote equity in spreading the responsibility for paying system marginal and fixed costs among all ratepayers. It would send clear, cost of service-based price signals that will incent customers to adopt storage technologies if they wish to further reduce their distribution bills, and it would maximize the value of customer-sited generation by promoting technologies that can provide high system capacity and GHG value during system peak hours. Cal Advocates' proposal is consistent with the Commission's residential rate design principles and the guiding principles in this proceeding and should be adopted.

LIST OF ATTACHMENTS FOR Chapter 3

#	Attachment	Description
1	3-A	Excerpt of PG&E's rebuttal testimony in the 2020 General Rate Case Phase 2 (A.19-11-019) showing the number of residential customers that are served by various final line transformer (FLT) types
2	3-B	Excerpt of PG&E's rebuttal testimony in the 2020 General Rate Case Phase 2 (A.19-11-019) showing the number of customers that are served by various circuit types
3	3-C	Graph of annual exports ratio (percentage) vs. system size (kW) derived from Cal Advocates-SDGE DR 08 Q02-06 demonstrating that NEM 1.0 and 2.0 annual export percentages (%) decrease with smaller *and* larger PV system sizes*
4	3-D	SDG&E response to Cal Advocates DR 13 describing functionality of its advanced metering infrastructure (AMI)
5	3-E	Excerpt from PG&E Cost of Service Testimony in the 2020 General Rate Case Phase 2 showing the residential class' total "Primary" and "Secondary and New Business" marginal distribution capacity costs

CHAPTER 3

ATTACHMENT 3-A. Excerpt of PG&E's rebuttal testimony in the 2020 GRC Phase 2 (A.19-11-019) showing the number of residential customers that are served by various final line transformer (FLT) types (p. 7-Atch-A-2)

TABLE 7A-1
2017 PG&E FINAL LINE TRANSFORMERS CUSTOMER CHARACTERISTICS

	FLT Type	FLT Count	Total Customer Counts in PG&E Territory												NEM Penetration	2017 Total FLT Demand
			Residential			Agricultural			Commercial			Large Comm. & Industrial				
			Non-NEM	NEM	Total	Non-NEM	NEM	Total	Non-NEM	NEM	Total	Non-NEM	NEM	Total	(%)	(kW)
1	R	547,453	3,266,247	269,532	3,535,779	-	-	-	-	-	-	-	-	-	8%	12,595,480
2	A	58,522	-	-	-	60,713	1,033	61,746	-	-	-	-	-	-	1.7%	3,485,461
3	C	120,795	-	-	-	-	-	-	303,136	5,561	308,697	-	-	-	1.8%	8,906,916
4	L	755	-	-	-	-	-	-	-	-	-	681	78	759	10%	1,658,290
5	RA	13,179	18,577	1,717	20,294	13,989	311	14,300	-	-	-	-	-	-	5.9%	323,071
6	RC	88,481	1,080,056	37,845	1,117,901	-	-	-	180,866	1,941	182,807	-	-	-	3.1%	3,331,082
7	RL	1	12	-	12	-	-	-	-	-	-	1	-	1	0%	1,379
8	AC	1,545	-	-	-	1,619	32	1,651	1,836	46	1,882	-	-	-	2.2%	88,863
9	AL	1	-	-	-	1	-	1	-	-	-	-	1	1	50%	1,529
10	CL	111	-	-	-	-	-	-	301	2	303	107	5	112	1.7%	218,378
11	RAC	1,305	2,339	178	2,517	1,401	28	1,429	1,446	32	1,478	-	-	-	4.4%	39,108
12	RAL	0	-	-	-	-	-	-	-	-	-	-	-	-	0%	0
13	ACL	0	-	-	-	-	-	-	-	-	-	-	-	-	0%	0
14	CRL	4	311	-	311	-	-	-	24	-	24	4	-	4	0%	8,159
15	RACL	0	-	-	-	-	-	-	-	-	-	-	-	-	0%	0
	TOTAL	**832,152**	**4,367,542**	**309,272**	**4,676,814**	**77,723**	**1,404**	**79,127**	**487,609**	**7,582**	**495,191**	**793**	**84**	**877**		**30,657,716**

Customer Class Definitions

R: Residential, A: Agricultural, C: Commercial, and L: Large Commercial and Industrial.

FLT Type Definition

An FLT can have one or more customer classes.

An FLT type is designated based on the customer classes served by that FLT. First letter of each customer class name is combined to designate an FLT Type.

For example, an FLT serving residential, agricultural, commercial and large commercial and industrial customer classes are desginated type "RACL".

ATTACHMENT 3-B. Excerpt of PG&E's rebuttal testimony in the 2020 GRC Phase 2 (A.19-11-019) showing the number of residential customers that are served by various circuit types (p. 7-Atch-A-12)

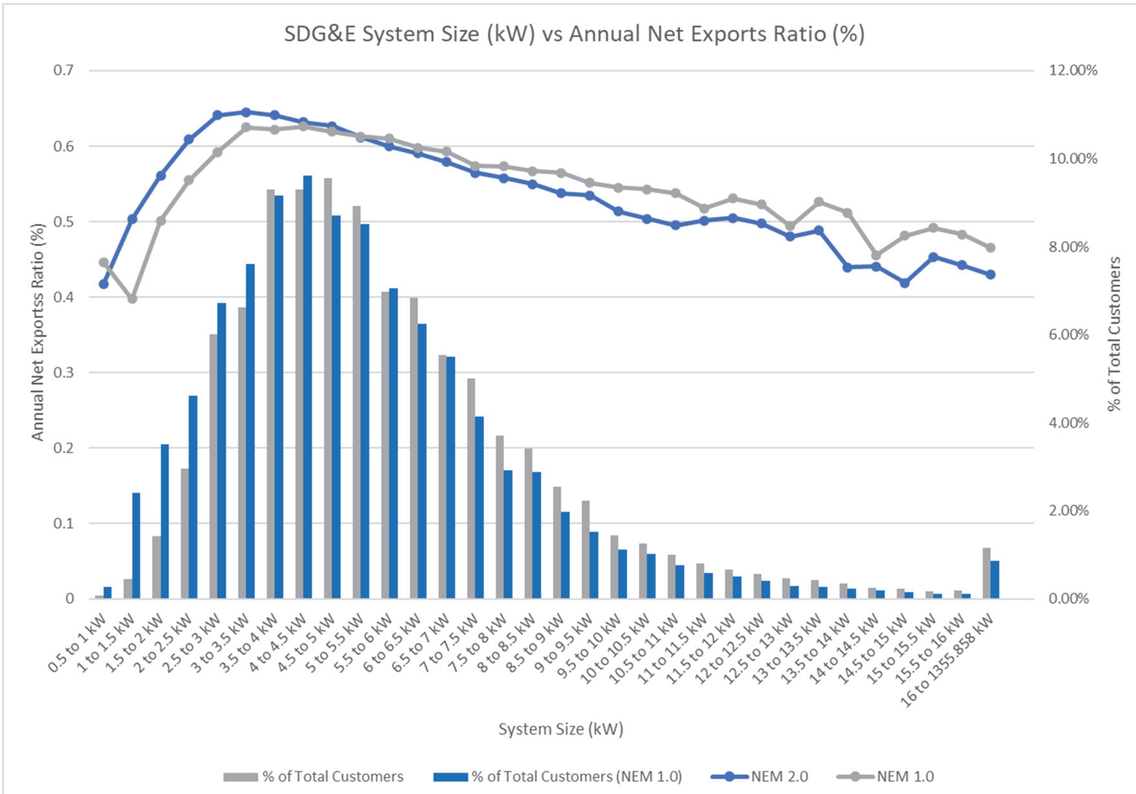
TABLE 7A-2
2017 PG&E DISTRIBUTION LEVEL CUSTOMER CHARACTERISTICS

	Circuit Type	Circuit Count	Total Customer Counts in PG&E Territory											
			Residential			Agricultural			Commercial			Large Comm. & Industrial		
			Non-NEM	NEM	Total	Non-NEM	NEM	Total	Non-NEM	NEM	Total	Non-NEM	NEM	Total
1	R	23	193	22	215	-	-	-	-	-	-	-	-	-
2	A	7	-	-	-	11	-	11	-	-	-	-	-	-
3	C	53	-	-	-	-	-	-	2,597	44	2,641	-	-	-
4	L	19	-	-	-	-	-	-		-	-	23	-	23
5	RA	4	7	1	8	15	2	17	-	-	-	-	-	-
6	RC	1,214	2,022,266	108,940	2,131,206	-	-	-	196,473	2,557	199,030	-	-	-
7	RL	-	-	-	-	-	-	-	-	-	-	-	-	-
8	AC	5	-	-	-	80	1	81	115	2	117	-	-	-
9	AL	1	-	-	-	1	-	1	-	-	-	-	1	1
10	CL	66	-	-	-	-	-	-	3,052	45	3,097	95	11	106
11	RAC	1,147	1,532,653	147,063	1,679,716	62,764	1,191	63,955	176,454	3,319	179,773	-	-	-
12	RAL	-	-	-	-	-	-	-	-	-	-	-	-	-
13	ACL	6	-	-	-	13	-	13	531	6	537	8	-	8
14	CRL	312	461,438	18,353	479,791	-	-	-	57,611	689	58,300	360	31	391
15	RACL	281	350,646	34,868	385,514	14,817	210	15,027	49,900	918	50,818	296	41	337
	TOTAL	**3,138**	**4,367,203**	**309,247**	**4,676,450**	**77,701**	**1,404**	**79,105**	**486,733**	**7,580**	**494,313**	**782**	**84**	**866**

Customer Class Definitions
R: Residential, A: Agricultural, C: Commercial, and L: Large Commercial and Industrial.

Circuit Type Definition
A circuit can have one or more customer classes.
A circuit type is designated based on the customer classes served by that circuit. First letter of each customer class name is combined to designate an FLT Type.
For example, a circuit serving residential, agricultural, commercial and large commercial and industrial customer classes are desginated type "RACL".

ATTACHMENT 3-C. Graph of Average Annual Exports Ratio (Percentage) vs. NEM 1.0 and NEM 2.0 Residential System Size (kW) demonstrating that annual export percentages decrease with smaller *and* larger PV system sizes[372]



* Based on full population level data of residential NEM 1.0 and 2.0 customers.

[372] Derived from Cal Advocates-SDGE DR 08 Q02-06.

ATTACHMENT 3-D. SDG&E response to Cal Advocates DR 13 Q2 explaining the functioning of Channel 1 and Channel 2 in its advanced metering infrastructure.

PUBLIC ADVOCATES OFFICE DATA REQUEST
CALPA-SDGE-DR-13
NET ENERGY METERING REFORM OIR – R.20-08-020
SDG&E RESPONSE
DATE RECEIVED: MARCH 29, 2021
DATE RESPONDED: APRIL 13, 2021

1. Cal Advocates' understanding is that, regardless of the meter interval reading, SDG&E's advanced metering infrastructure (AMI) is capable of reading electricity flow in both directions1 and that these flows are tracked in two separate channels by SDG&E's meters. Channel 1 of SDG&E's meters tracks metered consumption, or customer gross consumption net of any on-site generation that occurs simultaneously with on-site consumption. Channel 2 of SDGE's meters track net exports, or any instance in which on-site generation exceeds onsite consumption and electricity (kWh) is exported to the grid.
    a. Is Cal Advocates' understanding of how electricity flows are tracked in channels 1 and 2 of SDG&E's meters correct?
    b. If SDG&E's residential meters are not capable of instantaneous meter reading but rather the smallest interval reading is 5 minutes (for example), would this mean that Channel 1 inherently nets exports against consumption within 5-minute intervals? Or does channel 1 still measure customer gross consumption net of on-site generation that occurs simultaneously with that consumption? Please explain your answer in detail.
    c. Please further describe the AMI meters' capabilities.

SDG&E Response:

a. Yes, Cal Advocates' understanding of how electricity flows are tracked in channels 1 and 2 of SDG&E's meters is correct. Channel 1 records all metered consumption from the grid. Channel 2 records exports to the grid. Any self-generation that occurs simultaneously with on-site consumption would not be registered on the meter, as it occurs behind the meter.

b. Meter reads of channel 1 and 2 are not inherently netted. Channel 1 and 2 reads are recorded separately, regardless of what time interval the meter reads (e.g. every 15 minutes or 5 minutes). Netting is a billing construct that occurs in SDG&E's customer information and billing system after the interval data has been received from the meter.

c. Although SDG&E's AMI meters are capable of reading every 5 minutes, SDG&E currently has very limited application of 5-minute meter reads and does not use them for retail rate sites. For NEM customers, SDG&E's Customer Information System (CIS) is set up to receive, net out, and bill 15-minute interval data. For non-NEM residential customers, the CIS is set up for hourly meter reads, which is the standard meter read interval for those customers. To receive, net, and bill 5-minute interval data, the CIS billing system would require substantial buildout, along with significant changes to SDG&E's Smart Meter Network.

ATTACHMENT 3-E. Excerpt from PG&E's Cost of Service Testimony (Exhibit PGE-02) in the 2020 General Rate Case Phase 2 (A.19-11-019) showing the residential class' total "Primary" and "Secondary and New Business" marginal distribution capacity costs

TABLE 8-5
DISTRIBUTION COST OF SERVICE COMPARISON BETWEEN RESIDENTIAL NON-NEM AND NEM CUSTOMERS, 2017 RECORDED

Line No.			Non-NEM			NEM		
			Cost	Benefit	Net	Cost	Benefit	Net
1	Primary DMCR	Delivered	$445,800,799	-$344	$445,800,456	$51,950,625	$0	$51,950,625
		Received				$0	-$4,532,018	-$4,532,018
		Net	$445,800,799	-$344	$445,800,456	$51,950,625	-$4,532,018	$47,418,607
2	Secondary and New Business Primary DMCR	Delivered	$446,138,278	-$23,288	$446,114,989	$54,653,129	-$135,235	$54,517,893
		Received				$3,660,320	-$267,711	$3,392,608
		Net	$446,138,278	-$23,288	$446,114,989	$58,313,449	-$402,947	$57,910,502
3	Total DMCR	Delivered	$891,939,077	-$23,632	$891,915,445	$106,603,754	-$135,235	$106,468,519
		Received				$3,660,320	-$4,799,730	-$1,139,410
		Net	$891,939,077	-$23,632	$891,915,445	$110,264,074	-$4,934,965	$105,329,109
4	kWh	Delivered			27,853,656,478			2,599,496,305
		Received						1,411,388,928
		Net			27,853,656,478			1,188,107,378
5	Total DMCR Per kWh	Delivered	$0.03202	$0.00000	$0.03202	$0.04101	-$0.00005	$0.04096
		Received				$0.00259	-$0.00340	-$0.00081
		Net	$0.03202	$0.00000	$0.03202	$0.09281	-$0.00415	$0.08865

Note Please refer to Table 8-4A, column shaded light green, for calculation steps.

CHAPTER 4 SUCCESSOR TARIFF STORAGE TRANSITION PROPOSALS

(Witnesses: Alec Ward, Ben Gutierrez)

This Chapter details the final policy proposal for a successor tariff: incenting existing NEM customers to switch to the successor tariff using a storage rebate. This innovative proposal would greatly decrease the large NEM program cost burden while incenting paired storage, which responds to grid needs better than standalone rooftop solar. The proposal would also provide existing NEM customers a generous subsidy in exchange for their transition. Cal Advocates also proposes one-time cash payments for existing NEM customers to switch to the successor tariffs without investing in storage. To ensure the incentives are in all ratepayers' interests, the storage and one-time cash payment incentives should only be offered for a five-year period, after which all remaining NEM 1.0 and 2.0 customers should be automatically transitioned to the successor tariff.

I. INTEGRATING ENERGY STORAGE: INCENTING NEM 1.0 AND 2.0 CUSTOMERS TO TRANSITION TO SUCCESSOR TARIFF (A. Ward)

Chapter 2 of this Proposal discusses how NEM predominately encourages standalone rooftop solar, which does not maximize grid benefits.[373] Only 6% of NEM systems interconnected in 2019 were paired with energy storage.[374]

The successor tariff should be designed to encourage paired storage systems. Without paired storage, increased renewable energy from solar can ultimately have minimal or negative value as the generation added does not align with system needs.[375] The Whitepaper explains the benefits of paired storage as the "value that battery storage can provide by shifting solar generation from the lower-value midday hours to the higher-value evening hours."[376] The most recent report on SGIP also demonstrates paired storage can maximize the benefits of BTM generation by allowing generated energy to be used at times when it is more valuable to the grid,

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[373] "More than 90% of all megawatts (MW) of customer-sited solar capacity interconnected to the grid in the three large investor-owned (IOU) territories (PG&E, SCE, and SDG&E) in California are on NEM tariffs." See: https://www.cpuc.ca.gov/NEM/.

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

[375] See the growing annual rates of energy curtailment by CAISO: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[376] Whitepaper p. 11.

to meet peak grid demand, and reduce GHG emissions.[377] If storage is dispatched to maximize grid benefits, it also has the potential to increase resiliency, support reliability during periods of system and local peak demand, and improve customer bill savings.[378] As evidenced by low adoption rates, energy storage is also a more nascent industry compared to standalone rooftop solar, and this policy proposal can aid its growth.

Statutory mandates also require that the Commission establish transition periods, allowing NEM customers to remain on their current NEM tariff for a period of time to set "a reasonable expected payback period based on the year the customer initially took service under the tariff."[379] D.14-03-041 established a 20-year transition period, beginning when the system was interconnected for NEM 1.0 customers.[380] The NEM 2.0 Decision established a 20-year transition period for NEM 2.0 customers.[381] Chapter 2 of this Testimony demonstrates that because the current NEM tariff is based on the full retail electricity rate, the current payback period is an unreasonably short three to eight years, and that the overcompensation to NEM 1.0 and 2.0 customers is creating an unsustainable cost burden.[382] In addition, more than 70% of NEM systems have been installed since 2015, meaning the majority of systems still have 15 years of overcompensation from NEM, further driving the cost burden well into the future.[383]

To create the reasonable payback periods required by statute, the Commission should incent existing residential NEM customers to switch over to the successor tariff by offering rebates on paired storage systems or a transition bonus. The storage rebates would generously compensate customers to switch to the new tariff with BTM systems that enhance grid benefits

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[377] ITRON, 2018 SGIP Advanced Energy Storage Impact Evaluation (January 29, 2020), p. 1-10. See https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf.

[378] 2018 SGIP Advanced Energy Storage Impact Evaluation, p. 4-14.

[379] Public Utilities Code § 2827.1(b)(6).

[380] *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, D.14-03-041 (March 27, 2014), p. 2.

[381] D.16-01-044, p. 100.

[382] A NEM 2.0 system can on average pay for itself in only three years for SDG&E customers, five years for PG&E customers, and eight years for SCE customers. Cal Advocates data requests IOUs: PGE-4, SDGE-5, SCE-6. See, Exhibit 4-A of this Testimony.

[383] Lookback Study, p. 24.

compared to stand-alone rooftop solar. If an existing NEM customer is unable to install storage, or would prefer to not install storage, then customers should also be offered a one-time cash payment (transition bonus) of lesser value to switch to the successor tariff. The transition bonus should be a lower dollar amount to induce paired storage due to its grid and GHG benefits. Existing NEM customers should be given the option of choosing whichever incentive fits their needs better (but should be prohibited from receiving both).

All existing residential NEM customers who do not take an incentive to switch to the successor tariff should be required to take service on the successor tariff at the end of five years. Currently, residential customers taking service on NEM 1.0 and 2.0 either have already paid off their systems with their utility bill savings, or they will within three to eight years.[384] Requiring existing customers to transition to the successor tariff after five years is reasonable because the majority of these systems would have paid for themselves at that time. In fact, all existing NEM customers, except SCE NEM 2.0 customers with systems installed after 2018 (10% of current NEM residential customers), will have already reached their system payback within this 5-year program window.[385] Additionally, the successor tariff would continue to provide meaningful bill savings to customers with onsite generation.

The Commission should reduce storage rebate and transition bonus offerings in a stepwise fashion over a 5-year period to incentivize current NEM customers to switch to the successor tariff sooner rather than later. NEM 1.0 customers should receive a 10% reduction in storage rebate or transition bonus level relative to NEM 2.0 customers, as they have received more years of payback for their BTM system. Any NEM 1.0 customer who interconnected their system before 2010 for PG&E, 2011 for SCE, and 2008 for SDG&E should be ineligible for the storage rebates or transition bonuses, as the remaining amount of cost burden they will create is less than the cost of the proposed incentives.[386]

For the first two years of this transition period, the Commission should require the utilities to offer NEM 2.0 customers a $3,200 rebate for the price of purchasing a paired storage

[384] A NEM 2.0 system can on average pay for itself in only three years for SDG&E customers, five years for PG&E customers, and eight years for SCE customers. Cal Advocates data requests IOUs: PGE-4, SDGE-5, SCE-6. See Exhibit 4-A of this Testimony.

[385] See: https://www.californiadgstats.ca.gov/charts/. Accessed June 7, 2021.

[386] See Table 4-11 in section II below.

system.[387,388] This rebate amount is commensurate with the average incentives SGIP provided general market residential customers to encourage storage interconnected in 2020.[389] The rebate is also similar to, but greater than the Sacramento Municipal Utility District (SMUD's) proposed rebate program offering customers $500-$2,500 if customers adopt paired storage.[390] The Commission should establish a $2,880 rebate for NEM 1.0 customers, which is 10% less than the rebate for NEM 2.0 customers.

The Commission should also require the utilities to offer NEM 2.0 customers a $1,500 transition bonus in the form of a one-time cash payment for the first two years. This bonus amount is almost half the storage rebate level. For NEM 1.0 customers, the transition bonus should be $1,350, which is 10% less than the bonus for NEM 2.0 customers.

Maintaining the initial incentive levels for two years would avoid creating an unmanageable rush of customers to receive the incentives within the first year of this program. For the third and fourth year, the Commission should drop both incentive levels by 10% each year. To avoid paying large incentives to customers about to automatically transition to the successor tariff, storage rebate levels should be capped at $1,000 and transition bonuses $500 during the final, fifth program year for NEM 2.0 customers, and capped at $900 and $450, respectively, for NEM 1.0 customers. To ensure CARE and FERA customers are equitably compensated for their transition to the new successor tariff, these customers should receive the full initial value of the storage rebate or transition bonus if they switch at any point over the 5-year window.

After the 5-year period, all remaining NEM 1.0 and 2.0 customers should be automatically transitioned to the successor tariff to align NEM compensation with state climate

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[387] "Solar batteries range from $5,000 to $7,000+." See: https://www.energysage.com/solar/solar-energy-storage/what-do-solar-batteries-cost/.

[388] The cost of storage is projected to drop significantly in coming years. IRENA, Electricity Storage and Renewables: Costs and Markets to 2030, p. 18. See: https://www.irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets.

[389] In 2020, the average incentive for residential general market customers to purchase and install storage through SGIP was $3,172.80. See "Real-Time Public Report," accessed March 5, 2021: https://www.selfgenca.com/home/resources/.

[390] SMUD, "SMUD 2021-2022 Rate Proposal overview, including proposed rate increases and new Solar and Storage Rate and programs," May 18, 2021, slide 36. See: https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2021/May/2021-05-18-Finance-and-Audit-Exhibit-to-Agenda-Item-1---Jennifer-Davidson-and-Eric-Poff.ashx.

and equity goals and applicable statutes. Customers automatically transitioned to the successor tariff after five years would not receive either the storage rebate or the transition bonus, as roughly 90% of these customers would have already achieved payback for their systems and would continue to save on their monthly bills due to the benefit provided to them through the updated NEM structure.

A. Transition Incentive Program

To implement the storage rebate and transition bonus, the Commission should require IOUs to create a new Transition Incentive Program.

1. Funding source

Within 60 days of the final decision on the successor tariff, the IOUs should file a Tier 1 Advice Letter creating balancing accounts[391] to track all costs associated with the Transition Incentive Program.

The Commission should require the utilities to begin accepting Transition Incentive Program applications three months after the Commission decides the successor tariff begins.

2. Application process

The Commission should adopt a process similar to SGIP's residential application process, including creating a two-step system, for applicants for this proposed program.[392] During the first application step, customers should submit their project application through a Reservation Request to the IOUs.[393] During the second step, customers should receive an Incentive Claim Form, where they request payment of the incentive after the project is complete.[394] The IOUs should stop accepting applications five years after the program begins.

Because the Transition to Storage Program would stop taking applicants after five years, and all existing NEM 1.0 and 2.0 customers would be automatically transferred thereafter to the

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[391] Balancing accounts track "the difference between actual expenditures associated with the balancing account and authorized for recovery by the CPUC, and the revenues collected within customer rates to cover those specific expenses; and to make sure ratepayers do not pay more than they should." See: https://www.cpuc.ca.gov/General.aspx?id=6442457516.

[392] *Self-Generation Incentive Program Handbook* (SGIP Handbook), January 26, 2021, p 16.

[393] SGIP Handbook, p 20.

[394] SGIP Handbook, p 20.

successor tariff, the final year of the program should be capped at $36 million.[395] This cap prevents paying the high costs of a late rush of applicants that are about to be transitioned to the successor tariff anyway. The IOUs should accept applications on a first-come-first-serve basis, but they should prioritize customers that qualify for SGIP's equity budget or equity resiliency budget. This prioritization would ensure that customers who are lower income, medically vulnerable, and at-risk for wildfire are at the front of the line.[396]

The Commission should use lessons learned from the "SGIP Process Streamlining Technical Working Group." On April 30, 2021, this group issued a report on ways to streamline the SGIP application process.[397]

3. Cost allocation

The Transition Incentive Program would save customers 16.1 billion to $24.5 billion by reducing the NEM cost burden.[398],[399] If all customers accept the full-value incentive within the first two program years, the total amount of money the Commission would have to collect for both Transition Incentive Program incentives ranges from $1.3 billion (if all customers accept the transition bonus) to $2.8 billion (if all customers accept the storage rebate) over the five-year incentive window.[400]

The highest possible cost of the total Transition Incentive Program incentives, if all customers accept the more expensive storage rebate at full value within the first two years of the program, is $2.8 billion. Cost recovery for the Transition Incentive Program should be capped at 1/5th of the balance in the Transition Incentive Program Balancing Account. Permitting cost

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395 This cap was calculated to permit at least 1/5th of the number of customers to reach the $560 million annual cost recovery cap, to receive a $1,000 storage rebate in the final, fifth year of the Transition Incentive Program.

396 See: https://www.cpuc.ca.gov/sgipinfo/.

397 "Self-Generation Incentive Program Process Streamlining Report," R.20.05.012 (April 30, 2021).

398 Cal Advocates cost burden workpapers are available to parties upon request.

399 The Transition Incentive Program cost burden savings is further detailed later in this Chapter.

400 Cal Advocates cost burden workpapers are available to parties upon request.

recovery to be spread over multiple years prevents a spike in the cost burden and customers' bills.

The sooner existing NEM customers transition to the proposed successor tariff, the greater the benefit to customers without rooftop solar because it would reduce their overall cost burden. The Transition Incentive Program's higher incentives for earlier adoption, and the possibility of missing out on incentives if the program funding cap is surpassed in the final year of the program, should both incent customers to take the incentives earlier.

Funding for the incentives should be collected through IOUs' distribution charges. Distribution charges are driven by "capital additions and ongoing infrastructure modernization and improvements to the distribution system"[401] Distribution charges are the best method for cost recovery of these incentives because they also apply to unbundles customers. Unbundled customers, i.e., customers that receive their electricity generation services from a third-party provider, pay distribution charges to the IOUs.[402] Utilizing the distribution charge's ability to reach all customers is justified as all customers would benefit from the decreased NEM cost burden, as well as the grid and environmental benefits provided by the program's paired storage.

In 2019, the distribution revenue requirement across the IOUs was $12.23 billion.[403] The Transition Incentive Program would lower distribution charges, even during years of cost recovery. Afterwards, it would drastically decrease the cost burden caused by NEM, lowering its impact on the distribution rate. With cost recovery for the Transition Incentive Program capped at 1/5th of the costs recovered per year, the highest possible year of program costs, if all

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[401] *California Electric and Gas Utility Report: AB 67 Report to the Governor and Legislator,* April 2020, p. 18. See: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf.

[402] *Community Choice Aggregation En Banc Background Paper*, February 1, 20217, p. 2. See: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/CCABackgroundPaperv2.pdf.

[403] SDG&E' 2021 distribution revenue requirement was $1,733,469,000. *Supplemental: Consolidated Filing to Implement February 1, 2021, Electric*, Advice Letter 3669-E (February 1, 2021), p. 19.

SCE's revenue requirement was $5,348,167,000. *Implementation of Southern California Edison Company's Consolidated Revenue Requirement and Rate Change on February 1, 2021*, Advice Letter 4377-E (December 22, 2020), p. 4.

PG&E's revenue requirement was $5,153,003,469. *Advice Letter 6004-E-Bplementation of PG&E Annual Electric True-Up,* Advice Letter 6004-E-B (December 28, 2020), pp. 25-27.

customers accept the storage rebate during the first program year, would be roughly $560 million. The beneficial impacts of Cal Advocates' proposal on the cost burden would be significant. If all existing NEM customers move immediately to Cal Advocates' proposed successor tariff, the cost burden would be reduced by $1.14 billion in 2022.[404] The net result of the reduction in cost burden and program costs in 2022 would be a decrease of the distribution charges of 4.7%.

For a comparison in program size, the NEM cost burden in 2021 will cost ratepayers $3.37 billion.[405] Ratepayers paid $1.23 billion in 2019 to fund CARE incentives.[406] The Transition Incentive Program would save ratepayers $16.3 to $24.5 billion in total over 20 years.[407]

4. Program requirements

If an existing NEM customer accepts the storage rebate, they should follow certain rules already supplied by SGIP to ensure their storage system maximizes grid benefits.[408] These rules would not be applicable to customers that do not take the storage rebate, including customers who take the transition bonus.

To ensure customers taking the storage rebate install systems that benefit the grid and environment, and that they use their storage system for more than just back-up emergency purposes, the Transition Incentive Program should follow SGIP's GHG signal[409] and discharge

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[404] Cal Advocates cost burden workpapers are available to parties upon request.

[405] Cal Advocates cost burden workpapers are available to parties upon request.

[406] SDG&E expenditures for the CARE rate discount in 2019 totaled $104,986,999. *Annual Report Activity of San Diego Gas & Electric Company (U 902 M) on Low Income Assistance Programs for 2019,* A.14-11-007 (May 1, 2020), p. 65.

SCE expenditures for the CARE rate discount in 2019 totaled $487,221,423. *Southern California Edison Company's (U338-e) 2020 Annual Report for 2019 Low Income Programs*, A.14-11-007 (May 1, 2020), p. iv.

PG&E expenditures for the CARE rate discount in 2019 totaled $638,701,809. *Annual Report of Pacific Gas and Electric Company (U 39 M) on the Results of Its Energy Savings Assistance and California Alternate Rates for Energy Programs*, A.14-11-007 (May 1, 2020), p. 48.

[407] Cal Advocates cost burden workpapers are available to parties upon request.

[408] See D. 21-02-007, p. 46: "(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."

[409] The GHG signal "provides energy storage developers with information they need to charge the storage system during low-GHG emission periods and to discharge during high-GHG emission periods to reduce GHGs and remain in compliance with the statute." SGIP Handbook, p. 47.

standards.[410] To reduce GHG emission and peak grid demand, customers that receive a storage rebate should also be required to enroll on a TOU rate with a summer peak to off-peak price differential of 1.69 or more.[411] To prevent system oversizing, the Transition Incentive Program should also adopt SGIP's system sizing limitations.[412]

The Transition Incentive Program is distinct from SGIP. The Transition Incentive Program serves the targeted purpose of incenting existing residential NEM customers to transition to the successor NEM tariff, and to maximize the grid benefits of their current NEM BTM generation system. The targeted customers are different, as the Transition Incentive Program would only be available for existing NEM customers to pair their NEM BTM generation with paired storage. SGIP has no such limitations. The Transition Inventive Program also offers a transition bonus option, without the need to purchase a paired storage system. The Transition Incentive Program's funding source, distribution charges, is also different. SGIP is funded through the Public Purpose Program charge.[413] SGIP's current budget is capped by SB 700 (Weiner, 2018).[414]

Transitioning existing NEM customers to the successor tariff within five years, while offering them storage or transition incentives to transition sooner, would reduce the cost burden by $16.3 billion to $24.5 billion from a total of $41.1 billion over all remaining years of their

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[410] "Residential systems are required to discharge a minimum of 52 full discharges per year." SGIP Handbook, p. 50.

[411] "All new residential IOU and non-IOU customers are required to enroll in a time-varying rate with a peak period starting at 4 pm or later and with a summer peak to off-peak price differential of 1.69 or more, if such rate is available." SGIP Handbook, p. 51.

[412] "Energy storage projects that are not receiving equity budget resiliency incentives or receiving the resiliency adder, whether paired or stand-alone, may be sized up to the Host Customer's previous 12-month annual peak demand (kW)." SGIP Handbook, pp. 49-50.

[413] D.20-01-021, p. 81.

[414] The Commission "may authorize the annual collection of not more than double the amount authorized for the self-generation incentive program in the 2008 calendar year." Weiner, Stats. 2018, Ch. 839.

current 20-year transition period status.[415] Limiting NEM tariff reform to new participants in the successor tariff would only reduce the costs burden by $1.75 billion annually.[416]

II. THE NET PRESENT VALUE ANALYSIS TO MEASURE THE REDUCTION IN COST BURDEN OF CAL ADVOCATES' PROPOSAL (B. Gutierrez)

This section will present the calculations of the total reduction to the NPV of the NEM 1.0 and 2.0 cost burdens under Cal Advocates' proposal to transition NEM 1.0 and 2.0 customers to the successor tariff, as described in Section I above.

A. Though Cal Advocates' successor tariff proposal will significantly reduce the magnitude of new cost burdens created, it does not address the cost burdens already created under NEM 1.0 and NEM 2.0.

Under current Commission policy, NEM 1.0 and 2.0 customers are allowed to continue to take service on their NEM 1.0 or 2.0 tariff for 20 years from the date of their interconnection (20-year transition period).[417] As a result, general ratepayers will continue to experience an ongoing cost burden from the NEM 1.0 tariff until 2037 and from the NEM 2.0 tariff until 2042. The current total NEM 1.0 and 2.0 annual cost burden is unreasonable ($3.37 billion per year[418]) and creates an annual recurring burden in residential retail rates. Cal Advocates' successor NEM Tariff proposal would reduce the total net present value (NPV) of the NEM 1.0 and 2.0 cost burden by $16.3 billion to $24.5 billion, or a 39.6% to 59.8% reduction, over all NEM 1.0 and 2.0 customers' remaining years of their transition periods. Without reforms, the current NEM 1.0 and 2.0 tariffs will produce over $41.1 billion in total cost burden to ratepayers over the next 20 years.

Cal Advocates uses a total NPV calculation to find that, with no reforms, the NEM 1.0 and 2.0 tariffs will create $41.1 billion in additional cost burden to ratepayers of the three largest IOUs over the next twenty years. The NPV analysis calculates the present value of a future stream of annual cost burdens per kW under the NEM 1.0 or 2.0 tariff over all remaining years of

[415] Cal Advocates cost burden workpapers are available to parties upon request.

[416] Cal Advocates cost burden workpapers are available to parties upon request.

[417] D.14-03-041, p. 2. D.16-01-044, pp. 4, 100.

[418] 2021 total cost burdens from Cal Advocates' PG&E, SCE, and SDG&E cost burden models, Summary tab.

the customers' transition periods. Cal Advocates used its cost burden models as the starting point for calculating the annual cost burdens per kW in 2022 (see Table 4-1 below).[419]

Table 4-1
Comparison of Residential NEM 1.0, 2.0 Cost Burdens per kW-yr. in 2022

	PG&E	SCE	SDG&E
NEM 1.0	$342.61	$315.36	$462.27
NEM 2.0	$327.27	$318.28	$383.29

The average annual cost burden per kW for NEM 1.0 customers is $342.61 per kW-yr. for PG&E, $315.36 per kW-yr. for SCE, and $462.27 per kW-yr. for SDG&E. Based on the residential average NEM 1.0 system size (4.99 kW), the *typical* SDG&E residential NEM 1.0 customer creates $2,307 in cost burden *per year* to other ratepayers.[420] The NEM 2.0 cost burdens per kW-yr. are slightly less than NEM 1.0 due to the treatment of NBCs and the requirement that customers take service on TOU rates,[421] but the NEM 2.0 tariff still creates inordinately large and unsustainable cost burdens on a per kW basis as illustrated in Table 4-1. A typical SDG&E residential NEM 2.0 customer creates $2,146 in cost burden per year to other customers.[422] Cal Advocates' cost burden model calculates the average cost burden per kW-yr. of each year from 2022-2030 using the allocation of NEM 1.0 and 2.0 interconnected PV kW among rate schedules in 2020, accounting for the annual roll-off of NEM 1.0 and 2.0 customers as their transition periods expire, and assuming average annual escalation of electric rates of 4% per year and an annual PV system degradation rate of 2% per year.[423] Cal Advocates performed a linear extrapolation of the annual cost burden per kW beyond 2030 (from 2031 to 2041).[424]

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[419] The cost burden for NEM 1.0 and 2.0 is the difference between total customer bill savings and total avoided costs, and it is calculated in the same way as for the successor tariff.

[420] Average NEM 1.0 system size derived from Cal Advocates-SDGE DR 03.

[421] The NEM 2.0 Decision defined four non-bypassable charges that customers are not allowed to net their exports against.

[422] $383.29 * 5.60 kW (average NEM 2.0 system size). Derived from Cal Advocates-SDGE DR 03.

[423] The system degradation rate reflects all factors that reduce PV performance over time, including module degradation, module failures, inverter failures, soiling, maintenance, and increased shading from vegetation. Itron performed a regression analysis and found the average system degradation rate, or decrease to PV system's capacity factors, was 2% per year in the California Solar Initiative (CSI). Itron and Verdant Associates, LLC, "CSI Final Impact Evaluation," January 28, 2021, pp. 76-78.

[424] For an example, see Attachment 4-B.

Cal Advocates discounted the annual cost burdens to their present value (in 2021 dollars) using a discount factor equal to the 10-year average inflation rate (from 2010 to 2020) of the U.S. Bureau of Labor Statistic's Consumer Price Index for Urban Consumers, or 1.7%.[425] The inflation rate is the most accurate choice of the discount factor (time value of money) for the NPV calculations, reflecting that most ratepayers have very limited or non-existent ability to "grow" their money and real costs should be measured relative to general inflation of consumer goods prices. The cost burden does not affect the utility's ability to collect its full revenue requirement,[426] but rather it is an ongoing payment from general ratepayers to NEM customers that prevents ratepayers from putting that money to beneficial uses and, possibly, earning interest on it. The discount rate of future cost burdens should reflect the time value of money of ratepayers.[427]

The inflation rate is the most accurate choice of the discount rate because most ratepayers are residential customers and most Americans today have no or very little ability to earn interest on money due to rising costs of living, debt, and investment risk aversion. A 2019 GoBankingRates survey of more than 1,000 adults found that 47% were had zero dollars invested in instruments that could make meaningful financial returns not taking advantage of any investment choices.[428] Of those who did invest, the most common form of "investment" was a deposit account, such as a checking or savings account, which typically have very low interest rates of around 0.1%.[429] Just 10% of survey respondents said they were investing in stocks

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[425] U.S. Bureau of Labor Statistics, Consumer Price Index News Release, 1/21/2021, accessed 4/5/2021 at https://www.bls.gov/news.release/archives/cpi_01132021.htm.

[426] The utilities have revenue decoupling, meaning they have the right to collect their Commission-approved revenue requirement regardless of annual variations in sales. Thus, if the utilities under-collect their expected revenues due to loss in sales and compensation under the NEM tariff, they simply make up for it by recovering the costs (revenues) from other ratepayers.

[427] The time value of money represents the opportunity for money to grow in value (earn interest) over time if put to productive use today, which means that a dollar in a future year is worth less than a dollar today.

[428] Investments choices included stocks (not including retirement accounts), bonds (not including retirement accounts), mutual funds (not including retirement accounts), exchange-traded funds (not including retirement accounts), cryptocurrency, real estate, individual retirement accounts, 401(k)s, or deposit accounts such as savings and checking accounts. Cameron Huddleston, "More than 47% of Americans Aren't Investing their Money," July 22 2019 https://www.yahoo.com/now/more-40-americans-aren-t-090000530.html

[429] *Ibid.*

outside of retirement accounts. In addition, nearly 70% of Americans would have difficulty meeting their financial obligations if their paycheck was delayed more than a week.[430] This situation of many Americans who are living paycheck to paycheck and have little to no investments-based interesting earning ability is caused by a variety of factors, including but not limited to the rising of cost living (e.g., the costs of housing, food, and medical expenses), unemployment, and high levels of debt.

The tenuous financial circumstances for most Californians means that a 6% increase in the cost burden from one year to the next is not a "cost savings" to most ratepayers, as would be the case if the discount rate was the utility's cost of capital (e.g. 7.68% for SCE[431]), but rather it is a substantial cost increase.[432] Therefore, the discount rate should reflect that most ratepayers, and especially those most vulnerable to and affected by the cost burden, have little ability to invest and the interest rates on their types of investments are low, so the change in real costs for them is most accurately measured against general inflation in prices of consumer goods.

Finally, Cal Advocates calculated the NPV of the total NEM 1.0 and 2.0 cost burdens by summing the future discounted stream of annual cost burdens per kW over all remaining years of customers' transition periods and multiplying the total interconnected capacity (kW) with the corresponding number of remaining years of the transition period. An example of the calculations for PG&E is provided below:

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[430] American Payroll Assocation, "Number of Americans Living from Paycheck to Paycheck On Decline Despite Pandemic," https://www.prnewswire.com/news-releases/number-of-americans-living-paycheck-to-paycheck-on-decline-despite-pandemic-301134207.html. Megan Leonhardt, " 63% of Americans have been living from paycheck to paycheck since COVID hit," https://www.cnbc.com/2020/12/11/majority-of-americans-are-living-paycheck-to-paycheck-since-covid-hit.html.

[431] 2021 Avoided Costs Calculator (ACC) Electric Model, "IRP_Inputs" tab.

[432] Any instance in which the annual growth in value is less than the discount rate, e.g., 6% average growth per year compared to a 7% discount rate, will result in a *lower value* in present dollars (present discounted value.

Table 4-2
Calculation of Total NPV of Cost Burden of PG&E Residential NEM 1.0 and 2.0 PV Systems over all Remaining Years of Customers' Transition Periods ($2021)

	NEM 1.0		NEM 2.0	
1	2	3	4	5
Number of Years Remaining in Transition Period	Total Installed NEM 1.0 Residential Capacity (kW)	NPV of Cost Burden over All Remaining Years of Transition Period	Total Installed NEM 2.0 Residential Capacity (kW)	NPV of Cost Burden over All Remaining Years of Transition Period
1	0	$330	0	$327
2	15,583	$659	0	$653
3	10,001	$1,014	0	$1,006
4	16,020	$1,380	0	$1,371
5	25,943	$1,745	0	$1,720
6	24,843	$2,107	0	$2,065
7	38,850	$2,460	0	$2,397
8	48,929	$2,809	0	$2,726
9	57,685	$3,173	0	$3,070
10	78,332	$3,540	0	$3,415
11	138,635	$3,910	0	$3,761
12	228,608	$4,282	0	$4,107
13	351,637	$4,657	0	$4,455
14	375,519	$5,034	0	$4,803
15	1,629	$5,414	323,042	$5,153
16	10,370	$5,796	346,858	$5,503
17	0	$6,181	401,534	$5,854
18	0	$6,569	600,100	$6,206
19	0	$6,960	559,212	$6,559
20	0	$7,352	33,000	$6,912
Total Cost Burden	1,422,584	$5,950,990,269	2,263,746	$13,543,491,467

The first column shows the total number of years remaining in a NEM 1.0 or 2.0 customer's transition period as of 2022. Columns 3 and 4 show the NPV of the future stream of cost burdens of a single kW of PV over all remaining transition period years. The NPV values represent the total cost burden imputing unbundled customers as bundled – in other words, it calculates the total cost burden that occurs in both the delivery and generation rates.[433] Columns 2 and 4 show the total residential NEM 1.0 and 2.0 installed capacity that has the corresponding number of years remaining of the transition period as of 2022.[434] Finally, Cal Advocates calculated the total NPV of the NEM 1.0 and 2.0 cost burdens across all NEM 1.0 customers by multiplying columns 2 and 3 and summing the results of each row (see "Total Cost Burden" row), and it does the same for columns 4 and 5. From 2022 forward, PG&E's NEM 1.0 tariff is expected to produce $5.95 billion in cost burden to general ratepayers and the NEM 2.0 tariff is expected to produce $13.54 billion in additional cost burden. In combination, PG&E ratepayers will be responsible for paying $19.5 billion to NEM customers beyond the avoided costs value their PV generation provides to customers over the next twenty years.

Cal Advocates performed the NPV calculations for NEM 1.0 and 2.0 customers of the three IOUs, the results of which are displayed below:

Table 4-3
NPV of Total Residential NEM 1.0 and 2.0 Cost Burden over All Remaining Transition Period Years for Customers of the Three Major IOUs (in Millions)

	SCE ($2021)	**PG&E ($2021)**	**SDG&E ($2021)**	**Total ($2021)**
NEM 1.0	$4,523	$5,951	$2,709	$13,183
NEM 2.0	$8,730	$13,543	$5,604	$27,877
Total	**$13,253**	**$19,494**	**$8,313**	**$41,060**

Each row shows the NPV of the NEM 1.0 or 2.0 cost burden for customers of the respective IOU over all future years of NEM customers' transition periods. Although the NEM 2.0 cost burden is smaller on a per kW basis than the NEM 1.0 cost burden, there is significantly

433 Trying to accurately forecast load departure from bundled service over the next twenty years would have been extremely difficult. In addition, when a customer departs service from IOU and opts to take generation service from another provider, the generation portion of the cost burden does not disappear but simply is transferred to the other provider's side of the bill based on their generation rates.

434 This data was provided by the IOUs. The IOUs provided data on the total amount of residential NEM 1.0 and 2.0 capacity interconnected in each year, and Cal Advocates added 20 years to get the total transition period. Then the analysis looks forward to 2022 and calculates the total amount of capacity that *x* years remaining of the transition period

more interconnected NEM 2.0 system capacity (kW) than NEM 1.0 capacity.[435] NEM 2.0 customers have more years on average remaining in their transition periods. The total remaining cost burden that the NEM 2.0 tariffs will impose on general ratepayers ($27.9 billion) is significantly higher than the NEM 1.0 tariff's cost burden ($13.2 billion). This highlights the urgent need to update the NEM program in order to alleviate unsustainable pressures on general ratepayers' rates and help to more equitably achieve the state's climate goals. Eliminating the subsidy associated with the NEM 1.0 tariff would leave 68% of the remaining cost burden in place and would perpetuate existing structural inequities and unsustainable impacts to nonparticipants.

In combination, the NEM 1.0 and 2.0 tariffs are expected to create an additional $41.1 billion in cost burden to customers of the three major IOUs over the next two decades beyond the cost burdens that they have already created. This will occur during the same time period that the state expects residents and businesses to adopt electric vehicles (EVs) and building electrification technologies on a larger scale, which will require large up-front capital outlays by customers. Electrification technologies often have higher capital costs than their gas-fired counterpart technologies. This points to two ways in which the NEM cost burden will impede the state's decarbonization goals: by substantially increasing the price of electricity which weakens the economics of fuel switching, and by requiring $41.1 billion in payments from general ratepayers to a small group of customers (NEM customers) at the same time ratepayers are expected to make new up-front investments in electrification technologies.[436]

Finally, the NEM 1.0 and 2.0 tariffs will create an extraordinarily large cost burden for general ratepayers to bear, especially as the price of electricity for their consumption has increased faster than inflation over the past five years and is expected to continue to increase faster than inflation in the future. Many customers have already seen significant increases in electric bill costs and have been or may begin to face energy affordability challenges in the near future. Instituting a modernized successor tariff that will fairly and equitably compensate

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[435] For instance, it is forecasted by the end of 2021 there will be 2,263,746 kW of interconnected residential NEM 2.0 capacity in PG&E's service territory while there will be 1,422,584 kW of interconnected NEM 1.0 capacity. Similarly, there will be 798,360 kW of interconnected residential NEM 2.0 capacity in SDG&E's service territory and only 473,705 kW of NEM 1.0 capacity. Cal Advocates' PG&E and SDG&E cost burden models, Storage_OnSite PV tab.

[436] See chapter 2 section II.B on vehicle electrification.

customers for the value of their PV generation while reducing harms to nonparticipants is imperative.

1. Cal Advocates' NEM 1.0 and 2.0 reform proposal would reduce the total NEM 1.0 and 2.0 cost burden to general ratepayers by \$16.27 to \$24.5 billion (39.6% to 59.8%) over the next two decades.

i. Shifting NEM 1.0 and 2.0 customers onto the successor tariff would result in significant reductions to the cost burden even after accounting for BTM storage.

Cal Advocates calculated the total reduction to the NPV of the NEM 1.0 and 2.0 cost burden under its proposal by using the NPV of the NEM 1.0 and 2.0 cost burden under no reform of the tariffs (as described in section (A) above) and subtracting the NPV of the cost burden assuming all NEM 1.0 and 2.0 customers are transitioned to the successor tariff *with 100% of customers accepting the storage rebate offer and installing BTM batteries.* The NPV of the cost burden under the successor tariff is calculated in the same way as the NPV for NEM 1.0 and 2.0: by summing a stream of future annual cost burdens per kW with the addition that it includes the annual cost burden created by BTM batteries and includes up-front storage rebate costs. Although BTM storage provides greater avoided costs value than stand-alone PV,[437] BTM storage creates a cost burden because compensation of battery energy discharges at full retail rates is greater than the energy's avoided costs value to the system. For instance, a customer who takes service on SCE's TOU-D-PRIME rate and who charges their battery from on-site PV would earn average net bill savings of \$0.26194/kWh for every kWh discharged,[438] yet they would only provide \$0.1265/kWh in average avoided costs value for every 1 kWh discharged.[439]

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[437] This is because storage can discharge during the TOU peak/mid-peak period (4-9pm) when avoided capacity costs, and avoided GHG emissions, are highest. BTM storage devices lose some electricity in the process of charging and discharging (round-trip efficiencies or RTE are less than 100%), but current RTEs are high enough that even after accounting for the increased costs to the system of charging, the battery provides positive *net* avoided costs to the grid that are greater than the avoided costs value of PV-only on a per kWh basis.

[438] This accounts for the battery's round-trip efficiency (RTE) of 90%. 1/0.9 = 1.11 kWh of charging for every 1 kWh discharged. Average annual compensation for avoided Peak/Mid-Peak consumption under TOU-D-PRIME is \$0.34281/kWh minus the opportunity cost of not exporting 1 kWh of solar generation to the system. \$0.34281 - \$0.0728*1.11 = \$0.26194/kWh.

[439] This assumes the battery is operated entirely for time-of-use (TOU) arbitrage, so it charges from the

Since the customer's bill savings per kWh discharged is larger than the avoided costs value provided to the system, every kWh discharged creates $0.26194 - $0.1265 = $0.13544/kWh of cost burden.

Despite the incremental cost burden that is created by BTM storage, Cal Advocates' proposal to transition all NEM 1.0 and 2.0 customers to the successor tariff would result in a total reduction to the NPV of the NEM 1.0 and 2.0 cost burden of $16.06 billion or 39.1%. Cal Advocates modeled the cost burden of solar-plus-storage under its proposed successor tariff using the same general method that it used to model the solar-only cost burden. Cal Advocates developed a set of annual charging and discharging production weights by TOU period for a typical BTM storage device and multiplied the TOU production weights by the retail rates to calculate customer bill savings.[440,441] Cal Advocates assumed that the batteries would be operated entirely to perform TOU arbitrage: taking advantage of the largest volumetric price differentials in the TOU rates by charging entirely from on-site PV (or during the lowest price TOU period) and discharging during the highest price TOU periods.[442] Cal Advocates modeled the cost burden of the battery as an incremental module to the PV cost burden and converted the storage cost burden ($/kW) into a cost burden per kW-yr. of solar PV using the ratio of average

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PV systems and discharges during the highest price TOU period. $0.20741/kWh annual average avoided costs of peak/mid-peak discharging minus $0.0728 opportunity cost value of not exporting 1 kWh of PV generation to the grid adjusted for 90% RTE. $0.20741 – 0.0728*1.11 = $0.12654/kWh.

[440] See Attachment 4-C for an example of the storage production weights for SCE. Cal Advocates ran two scenarios – one in which the battery charges from on-site PV and the other in which the battery charges from the grid. See the following paragraph for more details.

[441] The general assumptions of the storage device's configuration for all three IOUs were an average power rating of 5 kW, average capacity of 13.5 kWh, 90% round-trip efficiency, 90% daily depth of discharge, one full cycle of charging and discharging per day, and the assumption that the battery is operated entirely for time-of-use (TOU) arbitrage. See Attachment 4-D for more details.

[442] This type of behavior maximizes total compensation (bill savings) to the customer under a TOU price structure because the customer charges either from on-site PV or during the lowest TOU price hours and discharges to offset their metered consumption during the highest price TOU hours.

NEM 1.0 and 2.0 system sizes (kW) to a 5 kW battery.[443] The results are shown below using SCE's TOU-D-PRIME rate.[444]

Table 4-5
Comparison of Average Cost Burden per kW-yr. of NEM 1.0, 2.0, and Successor Tariff under SCE's TOU-D-PRIME Rate in 2022

DER Tariff	Rate Schedule	Technology	Average Annual Cost Burden ($/kW-yr.)
NEM 1.0 – No Reform	Mixed composition of all NEM 1.0 customers	Solar PV only	$372.79[445]
NEM 2.0 – No Reform	Mixed composition of all NEM 2.0 customers	Solar PV only	$334.48
Successor Tariff	TOU-D-4-9	Solar PV only	$118.11
Successor Tariff	TOU-D-PRIME[446]	Paired storage – battery charges from grid	$136.33
Successor Tariff	TOU-D-PRIME	Paired storage – battery charges from on-site PV	$230.02

Assuming the customer charges their battery from the grid, shifting a customer from NEM 1.0 (PV-only) to the successor tariff (solar-plus-storage) would reduce the cost burden by

[443] For instance, SGD&E average NEM 1.0 and 2.0 system size is 5.37 kW, so the battery's incremental cost burden was added to the PV system's cost burden per kW using a conversion ratio of 5/5.37 = 0.93. The average battery power rating is similar to SCE's assumption of average residential battery power rating of 5.04 kW over its 2020-2030 forecast of installations residential BTM storage. Derived from Cal Advocates-SCE DR 04 Q05 in R.14-07-002.

[444] Cal Advocates SCE cost burden workpaper is available to parties upon request.

[445] All of the cost burden estimates in this table do not include any PV degradation so that the cost burden can easily be compared across NEM 1.0, 2.0, and the successor tariff. The analysis that Cal Advocates conducted did include a PV system degradation rate for all tariffs, however.

[446] TOU-D-PRIME is a residential optional TOU rate for large users and those who own batteries, EVs, or heat pumps. It features large daily TOU price differentials between the high cost TOU period and lowest cost TOU period year-round, which is optimal for maximizing bill savings from the battery.

$236.46 per kW-yr. ($372.79 - $118.11). The cost burden with the battery charging from the grid is only slightly higher than the PV-only successor tariff cost burden ($103.02/kW-yr.).[447] The customer would pay full retail rates for charging, and the TOU price differentials between On-Peak (discharging) and Off-Peak (charging) under the TOU-D-PRIME rate more closely reflect the TOU marginal costs differences than under the default TOU rate TOU-D-4-9. Thus, the customer's compensation is more closely linked to the marginal costs value provided to the system, and the increase to the cost burden caused by the battery ($18.22 per kW-yr.[448]) is small.

In contrast, a customer who charges from on-site PV converts low value mid-day PV generation ($0.05477/kWh) into higher peak avoided costs (e.g., $0.13597/kWh[449]) but they are compensated for avoided peak consumption at full retail rates (e.g., $0.34534/kWh[450] under TOU-D-4-9), so their total compensation is greater than avoided costs value. The cost burden of solar-plus-storage with the battery charging from on-site PV is $230.02 per kW-yr. or $111.91 per kW-yr. higher than for stand-alone PV ($118.11 per kW-yr.). However, there is still significant reduction to the cost burden of transitioning customers from NEM 1.0 to the successor tariff with paired storage (charging from on-site PV) of $142.77 per kW-yr. There would also be significant cost burden reductions of transitioning a customer from NEM 2.0 to the successor tariff with paired storage. It would also result in significant increases in total benefits (avoided costs) provided to the system per kW of PV from $94 per kW-yr. (PV only) to $155.26 per kW-yr (paired storage).[451] Thus, Table 4-5 above, demonstrates that regardless of the source of the battery's charging, transitioning customers from NEM 1.0 or 2.0 to the successor tariff with paired storage would result in significant reductions to the annual cost burdens born by nonparticipants.

Cal Advocates compares the NPV of the annual stream of cost burdens of customers under the NEM 1.0 and 2.0 tariffs (calculated in part A) to the NPV of the cost burden with

[447] TOU-D-PRIME has larger TOU price differentials than the default TOU rate that more closely reflect the average marginal cost differences between TOU periods.

[448] $136.33 - $118.11 per kW-yr.

[449] This is SCE's average avoided costs of 4-9pm year-round from the 2021 ACC.

[450] This is the average of SCE's 6/1/2020 TOU-D-4-9 total retail rates year-round multiplied by storage production factors assuming the battery cycles once per day and discharges entirely during the hours 4-9pm.

[451] Cal Advocate SCE cost burden model, Summary tab.

solar-plus-storage under the successor tariff. The difference is the total reduction to the cost burden under Cal Advocates' proposal. Cal Advocates performs the NPV analysis for the successor tariff separately assuming that all customers charge their batteries *entirely from on-site PV* and assuming that all customers charge their batteries *entirely from the grid.* Cal Advocates performs a population-weighted average of the results using the population percentages of residential NEM 1.0 and 2.0 customers who own their PV systems (battery charges from on-site PV)[452] and those whose PV systems are third-party owned (battery charges entirely from the grid).[453] Customers who charge their battery from on-site PV produce a higher cost burden than customers who charge from the grid (see Table 4-5, above), and customers who charge from on-site PV make up the majority of the population in the analysis (e.g. 71%, 73% and 57% of PG&E, SDG&E, and SCE NEM 2.0 customers, respectively).[454] Thus, the analysis is conservative and errs on the side of caution by placing greater weights on higher storage cost burden estimates.

Finally, even after accounting for the additional cost burden that the BTM batteries may create beyond the customers' 20-year transition periods, transitioning customers from the NEM 1.0 and 2.0 tariffs to the successor tariff with paired storage would significantly reduce the NEM 1.0 and 2.0 cost burdens with no reforms. For instance, under Cal Advocates' proposal, if a NEM 1.0 customer only has 3 years remaining in their 20-year transition period, transitioning them to the successor tariff would result in 3 years of cost savings relative to the NEM 1.0 tariff even with installation of a battery. But at the end of the 3 years, their battery would continue to operate and create an annual cost burden during the remaining 7 years of its 10-year lifespan.[455]

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[452] Customers who own their PV systems have the legal rights to make modifications to their systems and would likely integrate their new storage device with their PV generator in order to convert low value mid-day PV exports into high-value avoided On-Peak consumption (compensated at full retail rate) and thus maximize their compensation under a net billing structure.

[453] Third-party owned systems are owned by the solar developer, a bank, or other financial institution(s). Cal Advocates assumes these customers do not have the legal rights to make modifications to their PV systems, so they would install their batteries as standalone devices and charge the batteries entirely from the grid.

[454] See Attachment 4-E.

[455] A 2017 study of grid-connected Lithium-ion battery by researchers at the National Renewable Energy Laboratory found that with active temperature management and by limiting the average daily depth of discharge, a battery lifespan of 7-10 years could be achieved. A 2020 study in Spain of different types of Li-ion batteries and modeling the behavior of residential solar-plus-storage customers in response to TOU

Therefore, Cal Advocates includes the cost burden of the batteries over their entire lifespan[456] to capture all risks of increased cost burdens to ratepayers under Cal Advocates' proposal. The batteries' available capacity is assumed to degrade at 3% per year[457] and the batteries are assumed to reach their end of life at 10 years.[458] Even after accounting for the cost burdens over the batteries' entire lifespans, Cal Advocates' proposal would result in a total reduction to the NPV of the NEM 1.0 and 2.0 cost burdens of at least $16.27 billion or 39.6%, as is shown in Table 4-9 below.

After including the entire lifetime cost burdens of the batteries in its calculations of the total cost burden of paired storage, Cal Advocates subtracts the NPV of the cost burden under the successor tariff with paired storage from the NPV of the cost burden under the NEM 1.0 and 2.0 tariffs to derive the total reduction to the NEM 1.0 and 2.0 cost burdens under Cal Advocates' proposal. The results are presented for the three IOUs below:

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rates found that battery lifespans of approximately 10-12 years could be achieved depending on depth of discharge and other factors. Both studies defined the batteries' end of life (EOL) as when their capacity reaches 70% of initial nameplate capacity. Kandler Smith, Aaron Saxon, Matthew Keyser, Blake Lundstrom, Ziwei Cao, Albert Roc, "Life Prediction Model for Grid-Connected Li-ion Battery Energy Storage System," presented at the 2017 American Control Conference, Seattle, Washington, August 2017, Conference Paper NREL/CP-5400-67102. Hector Beltran, Pablo Ayuso and Emilio Perez, "Lifetime Expectancy of Li-Ion Batteries used for Residential Solar Storage," *Energies*: 2020, *13,* 568; doi:10.3390/en13030568.

[456] In the example above, it would be the 3 years remaining of their transition plus inclusion of a stream of an additional 7 years of annual cost burdens of the battery. Or for NEM 1.0 and 2.0 interconnected kW that has 4 years of transition period remaining, Cal Advocates added a stream of 6 additional years of annual cost burdens, etc.

[457] The 3% linear annual degradation rate was a simplifying assumption chosen so that the battery's capacity would reach 70% of its initial capacity after 10 years, consistent with the definition of end of life as 70% of the battery's initial capacity defined in Kandler Smith et al. and Hector Beltran et al. See the footnote directly above for more details.

[458] After 10 years the battery is modeled to experience rapid capacity fade until its available capacity reaches 0% of nameplate capacity at 15 years. Considering that Cal Advocates modeled a high 80% daily depth of discharge (DOD) – which is a conservating assumption that increases the annual cost burden from the battery – a 10-year lifespan is conservative, and the batteries' lifespans might be much shorter. Kandler Smith et al. found a 10-year Li-ion battery lifespan was possible but only if the daily DOD was kept to 55% or below. Similarly, Beltran et al. found battery lifespans of 10 or more years were possible but only if the battery was sized very large compared to PV system size, resulting in lower daily DOD. Kandler Smith, Aaron Saxon, Matthew Keyser, Blake Lundstrom, Ziwei Cao, Albert Roc, "Life Prediction Model for Grid-Connected Li-ion Battery Energy Storage System," presented at the 2017 American Control Conference, Seattle, Washington, August 2017, Conference Paper NREL/CP-5400-67102. Hector Beltran, Pablo Ayuso and Emilio Perez, "Lifetime Expectancy of Li-Ion Batteries used for Residential Solar Storage," *Energies*: 2020, *13,* 568; doi:10.3390/en13030568.

Table 4-9
Total Reduction to the NPV of the NEM 1.0 and 2.0 Cost Burdens Resulting from Cal Advocates' NEM 1.0 and 2.0 Transition Proposal

IOU/NEM Program	(1) NPV of Total Cost Burden: Business as Usual ($MM 2021)	(2) NPV of Total Cost Burden: Successor Tariff w/ Paired Storage ($MM 2021)	(3) Total Rebate Costs ($MM 2021)	(4) Total NPV of Successor Tariff w/ Storage + Rebates ($MM 2021)	(5) Change in NPV of Cost Burden from BAU ($MM 2021)	(6) Change in NPV of Cost Burden from BAU (%)
PG&E NEM 1.0	$5,951	$3,895	$858	$4,753	-$1,198	-20.1%
PG&E NEM 2.0	$13,543	$7,628	$698	$8,326	-$5,217	-38.5%
PG&E Total	**$19,494**	**$11,523**	**$1,556**	**$13,079**	**-$6,415**	**-32.9%**
SCE NEM 1.0	$4,523	$2,415	$301	$2,716	-$1,807	-40.0%
SCE NEM 2.0	$8,730	$4,603	$433	$5,036	-$3,694	-42.3%
SCE Total	**$13,253**	**$7,017**	**$734**	**$7,752**	**-$5,501**	**-41.5%**
SDG&E NEM 1.0	$2,709	$1,057	$255	$1,311	-$1,397	-51.6%
SDG&E NEM 2.0	$5,604	$2,326	$319	$2,644	-$2,960	-52.8%
SDG&E Total	**$8,313**	**$3,382**	**$573**	**$3,956**	**-$4,357**	**-52.4%**
TOTAL	**$41,060**	**$21,923**	**$2,864**	**$24,787**	**-$16,274**	**-39.6%**

Column 1 shows the NPV of the NEM 1.0 and 2.0 tariffs assuming there are no reforms to the tariffs. Column 2 displays the NPV under Cal Advocates' proposal assuming that 100% of customers install BTM storage. Cal Advocates models 100% of NEM 1.0 and 2.0 customers as taking service on PG&E's EV-2 rate, SCE's TOU-D-4-9 rate, and SDG&E's TOU-DR-1 rate, because the EV2 and TOU-D-4-9 are compatible with the requirement that customers take service on an SGIP-eligible rate in order to receive the storage rebate.[459] [460] Cal Advocates also

[459] SDG&E does not have a residential rate that is especially designed for storage at this time, and it plans to file a residential electrification-friendly rate application later this year. So, Cal Advocates simply used the default TOU rate for its analysis.

[460] Cal Advocates conservatively modeled all PG&E customers on EV2, because it is an EV and storage

modeled all customers as taking service on the proposed PG&E E-ELEC storage rate and on SCE's already adopted TOU-D-PRIME rate, both of which resulted in larger reductions to the cost burden than what is shown in Table 4-9 (e.g. $7.1 billion reduction to total SCE cost burden (-51.4%) under TOU-D-PRIME compared to $5.3 billion total reduction under TOU-D-4-9). So, to the extent that customers choose storage-specific rates with strong year-round TOU price differentials in order to maximize the annual bill savings from their storage system, the total reductions to the cost burden would be greater than what is shown in Table 4-9 above.[461]

Column 3 shows the total rebate costs assuming that 100% of customers accept the rebate offer in year 1—this shows the highest possible total rebate costs. Column 4 shows the total NPV of cost burden under the successor tariff with paired storage plus rebate costs. Finally, Columns 5 and 6 show the total change to the NPV of the NEM 1.0 and 2.0 cost burdens under Cal Advocates' proposal. Cal Advocates' proposal would reduce the NEM 1.0 and 2.0 cost burdens by $6.4 billion (-32.9%) for PG&E customers, by $5.5 billion (-41.5%) for SCE customers, and by $4.4 billion (-52.4%) for SDG&E customers.

The reduction to SDG&E's cost burden is highest because SDG&E has the highest residential retail rates of the three IOUs, resulting in the largest achievable NEM 1.0 and 2.0 cost burden reductions. However, Cal Advocates' proposal would result in significant reductions to the PG&E and SCE cost burdens and Cal Advocates' proposal would still save ratepayers billions in costs over the following decades while also increasing the total benefits (avoided costs) provided to the system. Cal Advocates' proposal would reduce the total future cost burden of the NEM 1.0 and 2.0 tariffs to customers of all three IOUs by $16.27 billion.

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rate. EV2 is a residential optional TOU rate that is open to all customers who own EVs and is available to storage-only customers up to a participation cap of 30,000 storage-only customers. Although it is not actually possible that all NEM 1.0 and 2.0 customers could take service on EV2 due to the storage-only participation cap, Cal Advocates conservatively modeled all customers as taking service on EV2 in order to model the *minimum* reductions to the cost burden. EV2 has steep Peak to Off-Peak price differentials ($0.3125/kWh in summer and $0.2854/kWh in winter) that provide ample opportunity for customers who have storage to experience large annual bill savings and create large cost burdens. Parties have proposed an E-ELEC rate open to all residential customers who have storage as part of a settlement in PG&E's 2020 General Rate Case Phase 2 (A.19-11-019), but the settlement has not yet been adopted by the Commission.

[461] Choosing such a rate would reduce the annual bill savings from their PV systems, however, so a customer's choice of a TOU rate will depend on the relative sizing of their PV and storage systems, how much of their PV generation they consume on-site, and other factors.

These are Cal Advocates' most conservative estimates of the reductions to the NEM 1.0 and 2.0 cost burdens under its proposal assuming that 100% of customers adopt storage, but total cost burden reductions could be significantly greater if customers choose the transition bonus instead of the rebate offer.

NEM customers would continue to receive significant financial benefits under the successor tariff. The average annual bill savings per kW of a new successor tariff customer *who has only PV (no BTM storage)* is $207.63 per kW-yr. (PG&E), $208.42 per kW-yr. (SCE), and $164 per kW-yr. (SDG&E).[462] This means that the average NEM customer who only has on-site PV would experience annual bill savings of $1,131 per year for PG&E, $1,119 per year for SCE, and $873 per year for SDG&E.[463] If the customer installs BTM storage and operates it to perform TOU arbitrage, annual bill savings would be significantly higher at $378 per kW-yr. of PV for PG&E, $451 per kW-yr. for SCE, and $430 per kW-yr. for SDG&E.[464] Average annual bill savings of a customer with paired storage would be $2,061 for PG&E, $2,424 for SCE, and $2,282 for SDG&E.[465] Thus, customers would continue to receive significant financial benefits under the successor tariff and there is ample opportunity for them to increase their financial benefits if they install BTM storage.

The Commission should require NEM 1.0 and 2.0 customers to transition to the successor NEM tariff with the offer of a declining storage rebate over a period of five years as outlined in sections I and II of this Testimony, because the successor tariff will produce more reasonable, cost-based, and equitable compensation of NEM customers' generation and even if every NEM

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[462] This assumes the customer takes service on the default TOU rate schedule or E-TOU-C for PG&E, TOU-D-4-9 for SCE, and TOU-DR-1 for SDG&E. Cal Advocates workpapers 1. PGE_Cost_Burden_Model, 2. SCE_Cost_Burden_Model, 3. SDGE_Cost_Burden_Model, Summary tab (PV-only annual bill savings per kW-yr.).

[463] Estimates are derived by multiplying annual savings per kW-yr. by average NEM 1.0 and 2.0 system sizes of 5.45 kW for PG&E, 5.37 kW for SCE and 5.31 kW for SDG&E. Cal Advocates workpapers 1. PGE_Cost_Burden_Model, 2. SCE_Cost_Burden_Model, 3. SDGE_Cost_Burden_Model, Summary tab (see PV-only residential annual bill savings per customer).

[464] This assumes the customer takes service EV-2 (PG&E), TOU-D-4-9 (SCE), and TOU-DR-1 (SDG&E). It also assumes the customer charges entirely from on-site PV. If they charge from the grid, bill savings would be less but would still be significantly higher than if the customer only had solar PV. Cal Advocates workpapers 1. PGE_Cost_Burden_Model, 2. SCE_Cost_Burden_Model, 3. SDGE_Cost_Burden_Model, Summary tab (Paired Storage annual bill savings per kW-yr.).

[465] Derived by multiplying annual savings per kW-yr by average PV system size. Cal Advocates workpapers 1. PGE_Cost_Burden_Model, 2. SCE_Cost_Burden_Model, 3. SDGE_Cost_Burden_Model, Summary tab (Paired Storage annual bill savings per customer).

1.0 and 2.0 customer accepts the storage rebate there would be significant decreases to the total cost burden.

The upper bound of the total reduction to the cost burden that Cal Advocates' proposal could achieve is presented in the following section.

ii. If All Existing NEM Customers Accept the Transition Bonus, the Reduction to the Total NEM 1.0 and 2.0 Cost Burdens Would be Greater at $24.5 Billion (-59.8%).

Cal Advocates proposes to offer customers the option of receiving a one-time cash payment – or a transition bonus – of $1,350 for NEM 1.0 customers and $1,500 for NEM 2.0 customers in lieu of the storage rebate. The reduction to the total NPV of the NEM 1.0 and 2.0 cost burdens would increase significantly if all NEM 1.0 and 2.0 customers accept the transition bonus, because there would be no additional cost burden from BTM storage and the transition bonus payments are smaller than the rebate payments. Customers may accept the transition bonus rather than the storage rebate for various reasons. Some customers may not wish to make the initial cash outlay to install a battery, or they may decide a battery is simply not a good fit for their needs. Cal Advocates models the reduction to the total NPV of the NEM 1.0 and 2.0 cost burdens using the same method as in part a) above, but assuming that 100% of customers accept the transition bonus and 0% of customers install BTM storage.[466] The results are provided below:

[466] The analysis assumes that 100% customers take service on the default TOU rates – that is, PG&E's E-TOU-C rate, SCE's TOU-D-4-9 rate, and SDG&E's TOU-DR-1 rate. The default TOU rates produce the highest annual bill savings for a PV-only customer and the largest cost burdens. To the extent that customers choose a rate that has stronger TOU price differentials than the default TOU rates - such as SCE's TOU-D-PRIME rate which is more beneficial to customers who own EVs - the reduction to the cost burden will be greater than what is shown in Table 4-10. Therefore the analysis in Table 4-10 is somewhat conservative, and cost burden reductions could be somewhat greater.

Table 4-10
Total Reduction in the NPV of the NEM 1.0 and 2.0 Cost Burdens of Cal Advocates' NEM 1.0 and 2.0 Reform Proposal assuming 100% of Customers Accept the Transition Bonus.

	(1) Total NPV of Cost Burden - Business as Usual ($MM 2021)	(2) Total NPV of Cost Burden - Successor Tariff ($MM 2021)	(3) Total Transition Bonus Costs ($MM 2021)	(4) Total NPV of Successor Tariff + Transition Bonus ($MM 2021)	(5) Change in Total NPV of Cost Burden from BAU ($MM 2021)	(6) Change in Total NPV of Cost Burden from BAU (%)
PG&E NEM 1.0	$5,951	$2,117	$858	$2,975	-$2,976	-50.0%
PG&E NEM 2.0	$13,543	$4,915	$698	$5,613	-$7,931	-58.6%
PG&E Total	**$19,494**	**$7,032**	**$1,556**	**$8,588**	**-$10,906**	**-55.9%**
SCE NEM 1.0	$4,523	$1,570	$301	$1,871	-$2,652	-58.6%
SCE NEM 2.0	$8,730	$3,227	$433	$3,660	-$5,070	-58.1%
SCE Total	**$13,253**	**$4,797**	**$734**	**$5,531**	**-$7,722**	**-58.3%**
SDGE NEM 1.0	$2,709	$544	$255	$799	-$1,910	-70.5%
SDGE NEM 2.0	$5,604	$1,285	$319	$1,604	-$4,000	-71.4%
SDGE Total	$8,313	$1,829	$573	$2,403	-$5,910	-71.1%
TOTAL	$41,060	$13,658	$2,864	$16,522	-$24,538	-59.8%

Under Cal Advocates' proposal, assuming all customers accept the transition bonus, the total reduction to the PG&E cost burden would be $10.9 billion (-55.9%), the reduction to the SCE cost burden would be $7.7 billion (-58.3%). the reduction to the SDG&E cost burden would be $5.9 billion (-71.1%), and Cal Advocates transition bonus proposal would save general ratepayers of the three major IOUs $24.5 billion (2021 dollars) over the next 20 years.

2. Customer Rebate Eligibility Analysis

Cal Advocates performed an analysis of the storage rebate eligibility cutoff year and recommends that customers who first took service on the NEM 1.0 tariff prior to

2013 for PG&E, 2011 for SCE, and 2008 for SDG&E should be excluded from the rebate offer to mitigate the risk to ratepayers of having to pay for incentives that would result in increases, not decreases, to the overall cost burdens. No eligibility cutoffs are necessary for NEM 2.0 customers, because the analysis indicates that total cost savings to ratepayers would exceed the costs of the storage device and the rebate for a typical NEM 2.0 customer regardless of the year they began service on the NEM 2.0 tariff.[467]

The customer eligibility cutoff analysis uses the same calculations as the NPV analysis presented above, except that the NPV calculations are performed at the level of an individual customer rather than on a per kW basis. The analysis uses the following formula to assess whether the rebate offer and the customer's installation of BTM storage would reduce or increase the total cost burden from the perspective of general ratepayers:

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[467] The analysis looks at the average size and other characteristics of a NEM 1.0 or NEM 2.0 system installed in each year, so it looks at a typical customer. However, there is wide variation in system sizes and annual export percentages, so there may be still become NEM 2.0 customers for whom the storage rebate offer it is not cost effective to ratepayers (does not result in reductions in the cost burden), but Cal Advocates' analysis indicates that regardless of the year they began service on the tariff a typical NEM 2.0 customer's acceptance of the rebate offer would result in positive cost savings to ratepayers.

Equation 4-1. Assessing the Net Change in the Cost Burden per Customer of Cal Advocates' Storage Rebate Offer

$$\boldsymbol{Change\ in\ Cost\ Burden = PVSize * NPV \sum_{i=1}^{t}(CostNEM - CostSuccessor) - Rebate\ Cost}$$

Where:

Change in cost burden is net change in NPV of the total cost burden per customer. Reductions in cost burden are measured as *positive* values, so if change in cost burden > 0 the rebate offer is cost effective from the perspective of ratepayers (cost savings > rebate and storage costs);

PVSize is PV system size (kW_{AC});

NPV measures the total net present value of the annual cost burden per kW over all remaining years of the transition period, from year (***i***) = 1 to the final transition period year (***t***). If ***t*** is less than 10 years, the NPV calculation also includes the cost burden of the battery over the remainder of its lifespan (10 years);

CostNEM is the annual cost burden per kW under the NEM 1.0 or 2.0 tariff in year ***i***;

CostSuccessor is the annual cost burden per kW of PV under the successor tariff with paired storage[468];

Rebate cost is the upfront storage rebate cost. It is set at the highest value (year 1) or $2,880 for NEM 1.0 customers and $3,200 for NEM 2.0 customers.

Reductions in the cost burden are measured as *positive* values (***Change in cost burden*** > 0). The equation yields a positive value, meaning the rebate offer is cost effective from the perspective of general ratepayers, if the total NPV cost savings of switching a customer from NEM 1.0 or NEM 2.0 to the successor tariff with paired storage (first term on right side of equation) is greater than the size of the rebate (second term).

Cal Advocates conducted the NPV analysis for the eligibility cutoff dates using the same assumptions as in its NPV analysis outlined in section A above.[469] The analysis compares the cost burden of a typical residential NEM 1.0 or 2.0 customer under the NEM 1.0 or NEM 2.0 tariff and under the successor tariff with paired storage over all remaining years of their

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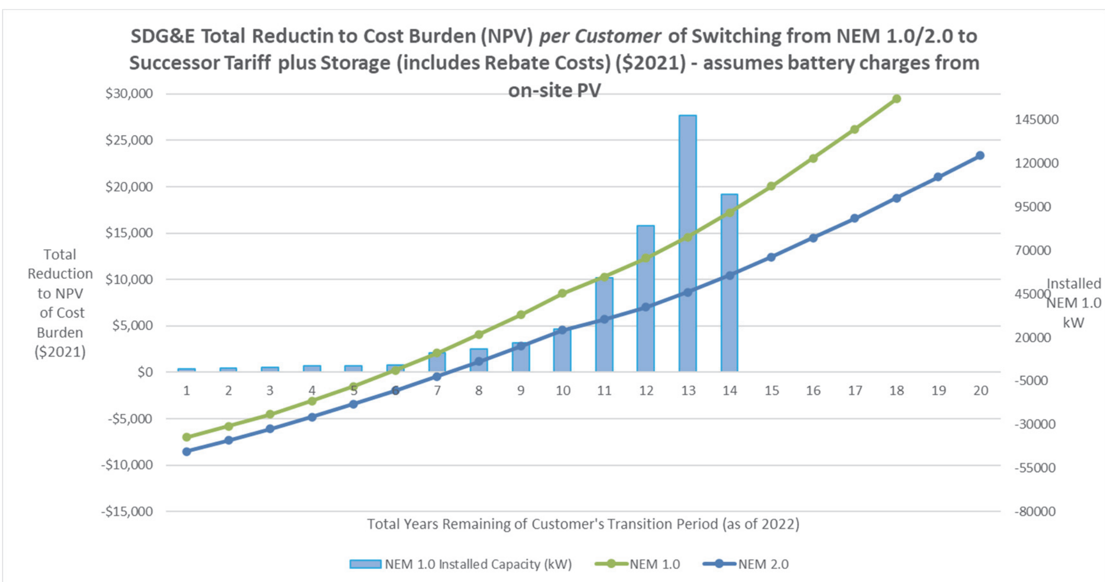
[468] The battery's cost burden is calculated using a population-weighted of customer-owned PV systems (battery charges entirely from on-site PV) and third-party ownership systems (battery charges entirely from the grid). The cost burden of the PV system is the same for customer-owned and third-party ownership systems.

[469] The assumptions include a 4 % annual escalation of electric rates, 2% annual PV degradation factor over time, 3% annual degradation in battery's available capacity, and a discount rate of 1.7%.

transition period. The analysis also takes into account the change in PV system sizes over time (***PVSize*** in Formula 4-1 above) using the IOUs' average residential NEM 1.0 and NEM 2.0 system sizes adjusted according to the slope (average annual increase) of newly interconnected NEM 1.0 and NEM 2.0 PV system sizes using annual interconnection data from the DGStats interconnection dataset.[470] This approach is appropriate because customers who interconnected their systems in earlier years tended to have smaller PV systems. The storage rebate offer is less cost effective for customers who interconnected in earlier years because they have fewer transition period years remaining over which the annual cost burden can be reduced and because their PV system sizes are smaller relative to the constant rebate level. The results of the analysis are displayed below for SDG&E:

Figure 4-1
Total Reduction to NPV of SDG&E NEM 1.0 and 2.0 Cost Burden under Cal Advocates' Storage Rebate Offer on a per Customer Basis ($2021)



The x-axis shows the customer's total number of years remaining in their transition periods while the left y-axis shows the total reduction to the NPV of the cost burden on a per

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[470] The slope is calculated over 2001-2020 for NEM 1.0 and over 2016-2020 for NEM 2.0 from the DGStats interconnection dataset. Any years with sample sizes of less than 100 were excluded from the analysis. The slopes are 0.162, 0.118, and 0.175 for PG&E, SCE, and SDG&E residential NEM 2.0 customers, respectively, and 0.105, 0.110, and 0.096 for PG&E, SCE, and SDGE NEM 2.0 customers. Cal Advocates' PG&E, SCE, and SDG&E Cost Burden workpapers, Storage_Grid Charging tab.

customer basis over all remaining years of the transition period.[471] For instance, a hypothetical NEM 1.0 customer with 15 years remaining of their transition period would produce $20,000 in cost burden reduction if they switched to the successor tariff, accepted the storage rebate, and installed BTM storge. Since the NEM 1.0 cost burden is larger on a per kW basis than the NEM 2.0 cost burden, total reductions to the cost burden under NEM 1.0 (green line) are higher than for NEM 2.0 (blue line) regardless of the number of years remaining.

The eligibility cutoff point is determined by the break-even points, or the two points at which the NEM 1.0 and 2.0 NPV cost burden reduction curves cross the x-axis. Cal Advocates defines the break-even point for storage rebate offer eligibility as the first year in which the green or blue lines have a positive value (so 6 years for NEM 1.0 (green) and 8 years for NEM 2.0 (blue), meaning that the *total reduction* to the cost burden exceeds total *increase in costs* of the BTM storage device and rebate costs. This translates to customers who interconnected their PV systems and firs took service on the NEM tariff in 2008 for NEM 1.0 and 2010 for NEM 2.0.[472] Any customer who began service on the tariff prior to 2008 for NEM 1.0 or prior to 2010 for NEM 2.0 should not be eligible for the storage rebate offer, because the increased costs of the storage device and the rebate would outweigh the benefits to ratepayers. Finally, the light blue bars show the total interconnected NEM 1.0 capacity. Any bars that are to the left of the break-even are not cost-effective (costs of the rebate offer would exceed reductions to the cost burden). Only 14,506 kW or 3.0% of total interconnected NEM 1.0 capacity is below the break-even point, indicating that Cal Advocates' rebate offer proposal is highly cost effective from the perspective of reducing the total cost burden to ratepayers. The corresponding bars of interconnected kW are not shown for NEM 2.0, but 100% of NEM 2.0 customers exceed the break-even point and would yield cost savings to ratepayers.[473] Although the percentage of interconnected NEM 1.0 capacity that does not exceed the break-even point is small, ratepayers

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[471] Thus, each point on the x-axis represents a different "vintage" of NEM 1.0 or 2.0 systems depending on the year the customer first took service on the NEM tariff.

[472] The analysis is performed using 2022 as the base year, so a break-even point of 6 years (NEM 1.0) means the customer first took service on the NEM tariff in 2022 + 6 – 20 = 2008.

[473] 100% of NEM 2.0 systems fall between 14 and 19 transition period years remaining in 2022 assuming the Successor Tarif is implemented at the beginning of 2022 and there are no additional (new) NEM 2.0 customers in 2022.

Cal Advocates SDGE cost burden workpaper, Storage_On-Site PV tab.

should not be responsible for giving further payments to these customers, because it is not cost effective and these customers have likely already recouped the initial costs of their systems plus interest. These customers should be presented the offer of the transition bonus and transferred to the successor tariff, under which they would still continue to earn considerable value for their system every year.[474]

Finally, Cal Advocates presents the resulting storage rebate cutoff eligibility dates for all three IOUs below.

Table 4-11
Comparison of Storage Rebate Eligibility Cutoff Dates for the Three IOUs

	PG&E Break-Even Point (Years)	PG&E Cutoff Year	SCE Break-Even Point (Years)	SCE Cutoff Year	SDG&E Break-Even Point (Years)	SDG&E Cutoff Year
NEM 1.0	8	2010	9	2011	6	2008
NEM 2.0	9	2011	14	2016	8	2010

The cutoff year represents the first year (or vintage year based on when the customer first took service on the NEM tariff) that customers should be eligible for the rebate offer. In other words, any SDG&E NEM 1.0 customer who interconnected their system in 2013 or later, any PG&E NEM 1.0 customer who interconnected in 2011 or later, and any SDG&E customer who interconnected in 2008 or later should be eligible to receive the rebate offer. This approach will maximize cost savings of the program to ratepayers and prevent ratepayers from having to incur rebate costs for customers whose adoption of storage would result in an increase in the cost burden to ratepayers. The eligibility cutoff years for NEM 2.0 are all in the same or prior year that the utility first implemented the NEM 2.0 tariff, so all NEM 2.0 customers should be eligible

[474] Average annual compensation (bill savings) for a PV-only system under Cal Advocates' successor tariff is $202.08 per kW-yr. for PG&E, $193.54 per kW per year in 2022, $205.34 per kW-yr. for SCE, and $180.26 per kW-yr. for SDG&E. Based on average NEM 1.0 and 2.0 system sizes of 5.45 kW for PG&E, 5.37 kW for SCE, and 5.3 kW for SDG&E, the *average* PG&E NEM 1.0 or 2.0 customer would earn $1,054 in bill savings per year, the average SCE customer would earn $1,102 in savings per year, and the average SDG&E customer would earn $982 in bill savings per year in 2022 under Cal Advocates' successor tariff proposal. A portion of their annual savings would continue to increase at the full retail rate, although exports compensation would be entirely disassociated from retail rates and instead linked to avoided costs value. Cal Advocates' PG&E, SCE, and SDG&E cost burden models, Summary tab. System sizes derived from DR Cal Advocates-PGE 03, Cal Advocates-SCE 03, and Cal Advocates-SDGE 03.

for the rebate offer. The Commission should adopt Cal Advocates' proposed eligibility cutoff dates to minimize the risk to ratepayers of paying for incentives that would result in increases to the cost burden and to maximize program's total cost burden reductions to ratepayers.

III. CONCLUSION

The Commission should adopt Cal Advocates' proposed transition of NEM 1.0 and NEM 2.0 customers to the successor tariff, which will bring customers' compensation more in alignment with the total value their generation provides to the system and to ratepayers. Cal Advocates' proposal would save ratepayers $16.3 to $24.5 billion in costs over the next two decades depending on NEM 1.0 and 2.0 customers' choice of the storage rebate offer or the transition bonus. Cal Advocates' proposal is effective at reducing the cost burden and producing a reasonable outcome that is equitable to all ratepayers while maintaining significant compensation for NEM 1.0 and NEM 2.0 customers' systems regardless of whether customers accept the rebate or the transition bonus. The Commission should adopt Cal Advocates' proposed storage rebate cutoff eligibility dates to minimize the risk of ratepayers funding some customers' purchases of battery storage systems that would lead to *increases* in the cost burden rather than decreases. Such customers should be excluded from the storage rebate offer to maximize the program's cost burden reductions to ratepayers.

LIST OF ATTACHMENTS FOR CHAPTER 4

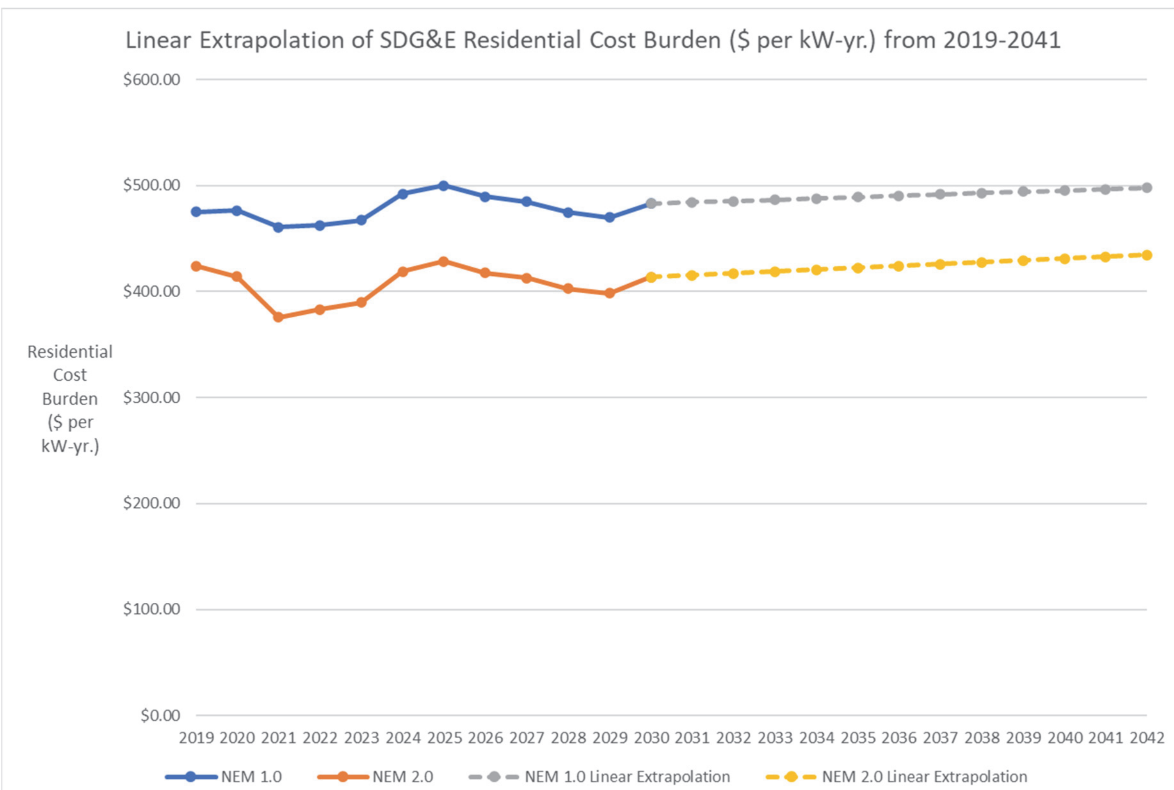
#	Attachment	Description
1	4-A	Cal Advocates' Date Request Regarding NEM Payback Periods
2	4-B	Cal Advocates' Forecast of SDG&E NEM 1.0 and 2.0 Annual Residential Cost Burden from 2019-2042
3	4-C	Cal Advocates' SCE residential BTM storage annual charging and discharging production weights by TOU period.
4	4-D	Cal Advocates' modeling assumptions of residential BTM battery specifications and operating behavior
5	4-E	Cal Advocates' Population Weights (%) for Combining NPV Cost Burden of Battery Grid-Charging and On-Site PV Charging under the Successor Tariff with Paired Storage

ATTACHMENT 4-A. Cal Advocates' Date Request Regarding NEM Payback Periods

See below for a summary of Cal Advocates Data Requests PGE-4, SCE-6, and SDGE-5 regarding the average payback period for NEM 2.0 customers.

Install Year	SDG&E Payback Period for NEM 2.0 Customers (years)	PG&E Payback Period for NEM 2.0 Customers (years)	SCE Payback Period for NEM 2.0 Customers (years)
2016	4.3		
2017	4.0	5	
2018	3.1	5	8
2019	3.1	5	8

ATTACHMENT 4-B. Cal Advocates' Forecast of SDG&E Residential NEM 1.0 and NEM 2.0 Annual Cost Burden ($ per kW-yr.) from 2019-2042



ATTACHMENT 4-C. Cal Advocates' SCE residential BTM storage annual charging and discharging production weights by TOU period.

SCE - Storage Production Weights		
	Battery Charge	**Battery Discharge**
Summer On peak	0%	23%
Summer Mid-Peak	0%	10%
Summer Off	-33%	0%
Winter Mid peak	0%	51%
Winter Off-Peak	-1%	16%
Winter Super Off	-65%	0%

ATTACHMENT 4-D. Cal Advocates' Modeling Assumptions of Residential BTM Battery Specifications and Operating Behavior

Input	Value
Power Rating - Constant (kW):	5[475]
Power Rating - Max (kW):	7
Total Storage Capacity (kWh)	13.5
Total Usable Capacity (kWh):	12.15
Daily Depth of Discharge (%):	80%
Round Trip Efficiency (%):	90%
Operating Behavior	TOU arbitrage

[475] The average power rating is similar to SCE's assumption of average residential battery power rating of 5.04 kW over its 2020-2030 forecast of growth in residential BTM storage. Derived from Cal Advocates-SCE DR 04 Q05 in R.14-07-002.

ATTACHMENT 4-E. Cal Advocates' Population Weights (%) for Combining NPV Cost Burden Results of Batteries that Charge from the Grid (Third Party-Owned PV) and Batteries that Charge from On-Site PV (Customer-Owned PV) under the Successor Tariff[476]

	% Of Total NEM 1.0/2.0 Residential Customers	
	Customer-Owned PV System	Third Party Owned PV System
PG&E – NEM 1.0[477]	71%	29%
PG&E – NEM 2.0	71%	29%
SCE – NEM 1.0	49%	51%
SCE – NEM 2.0	57%	43%
SDG&E – NEM 1.0	69%	31%
SDG&E – NEM 2.0	73%	27%

[476] Population weights are derived from data requests Cal Advocates-AW-PGE-2020-04, Cal Advocates-AW-SCE-2020-06, and Cal Advocates-AW-SDGE-2020-05.

[477] PG&E did not provide its customer-owned and third-party ownership population counts broken out by NEM 1.0 and 2.0. Therefore, Cal Advocates used the same aggregate customer-owne PV and third-party ownership PV weights for NEM 1.0 and 2.0.

CHAPTER 5 CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF MEETS THE COMMISSION'S GOALS

(Witnesses: Sophie Babka, Alec Ward, Ben Gutierrez, Nathan Chau, Adam Buchholz, Kristin Rounds)

Cal Advocates' proposed successor tariff would meaningfully decrease the cost burden and address the current NEM design's cost-effectiveness deficiencies. Cal Advocates' proposed successor tariff would also create fair treatment between residential and non-residential DER customers. It would also ensure overall sustainable growth for DERs, including a healthy solar industry, and better align California's DER incentives with other states experiencing similar DER growth.

I. CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF WOULD BETTER PROTECT CUSTOMERS (S. Babka)

Guiding principle (c) for this proceeding provides that "[a] successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services."[478] Cal Advocates appreciates this guiding principle and is filing its support of the Commission's efforts to offer NEM customer protections in R.14-07-002 on the *Assigned Commissioner's Ruling Proposing Recovery for NEM Solar Consumers*.[479] As stated by the Commission, solar fraud[480] is one of the many barriers to increasing the inclusion of low-income, elderly, and non-English speaking consumers who attempt to participate in NEM. Cal Advocates supports the *Proposed Decision on Solar Consumer Assistance (SCA) Fund for Net Energy Metering Customers* and the creation of a SCA fund to compensate customers who are harmed as a result of inadequate solar installations and are unable to receive assistance through Contractors State License Board (CSLB) processes.[481]

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[478] D.21-02-007, OP 1 guiding principle (c), p. 45.

[479] See generally Comments of the Public Advocates Office on the Assigned Commissioner's Ruling Proposing Recovery Fund for NEM Solar Consumers, filed October 1, 2020.

[480] Assigned Commissioner's Ruling Proposing Recovery Fund for Net Energy Metering Solar Consumers (Ruling), served September 3, 2020, pp 3-6. Examples of solar fraud include, but are not limited to, lead generators and sale agents misleading consumers into entering harmful transactions, misrepresentation in violation of Business and Professions Codes (BPC) § 7161 or a willful and fraudulent act in violation of BPC § 7116, workmanship in violation of BPC § 7109, and payment schedules in violation of BPC § 7159.

[481] Proposed Decision of Commissioner Guzman Aceves on Solar Consumer Assistance Fund for Net Energy Metering Customers, filed May 19, 2021, p. 31.

Furthermore, and as detailed in the next section, Cal Advocates' proposed successor tariff would protect all utility customers from unreasonably high rates driven by the large NEM cost burden.

II. CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF WOULD REDUCE THE COST BURDEN (B. Gutierrez and N. Chau)

Chapter 3 of this Proposal demonstrates that it would substantially lower the cost burden on nonparticipating customers by creating a successor tariff that is aligned with state equity and climate goals. In summary, this Proposal would lower the total annual cost burden of the successor tariff by $1.81 billion per year in 2021 dollars by 2030 compared to a continuation of the current NEM 2.0 rate structure (business as usual). In addition, this Proposal would reduce the total NPV of the cost burden of all NEM 1.0 and 2.0 customers by $16.3 billion to $24.5 billion in 2021 dollars over all remaining years of their transition period status, creating significant savings for ratepayers and helping to alleviate the unsustainable upward pressure on electric rates.

Reforming NEM through the combined changes in this Proposal would save nonparticipating customer between $158 and $237 each year by 2030.

With all of these reforms, participating residential customers would still receive generous payback periods on their investments of 7.8-12.4 years.

III. CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF WOULD ENHANCE PROGRAM COST-EFFECTIVENESS (S. Babka)

Cal Advocates' proposed successor tariff would enhance program cost-effectiveness, while other parties' proposals would now. The tables below show E3's RIM scores for Cal Advocates' proposed successor tariff compared to NEM 2.0 and CALSSA's proposed successor tariff.[482]

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[482] For this section Cal Advocates compares RIM scores and first year cost burden data using E3's Cost Effectiveness Study in order to ensure that comparisons are conducted using standardized assumptions across party proposals. At the time that this testimony was submitted, Cal Advocates has not had a chance to conduct a thorough review of the underlining assumption in E3's model and thus may need to submit errata testimony upon completion of a review.

Figure 5-1: E3's 2023 and 2030 Successor Tariff RIM Results for Residential Solar PV Non-CARE Customers

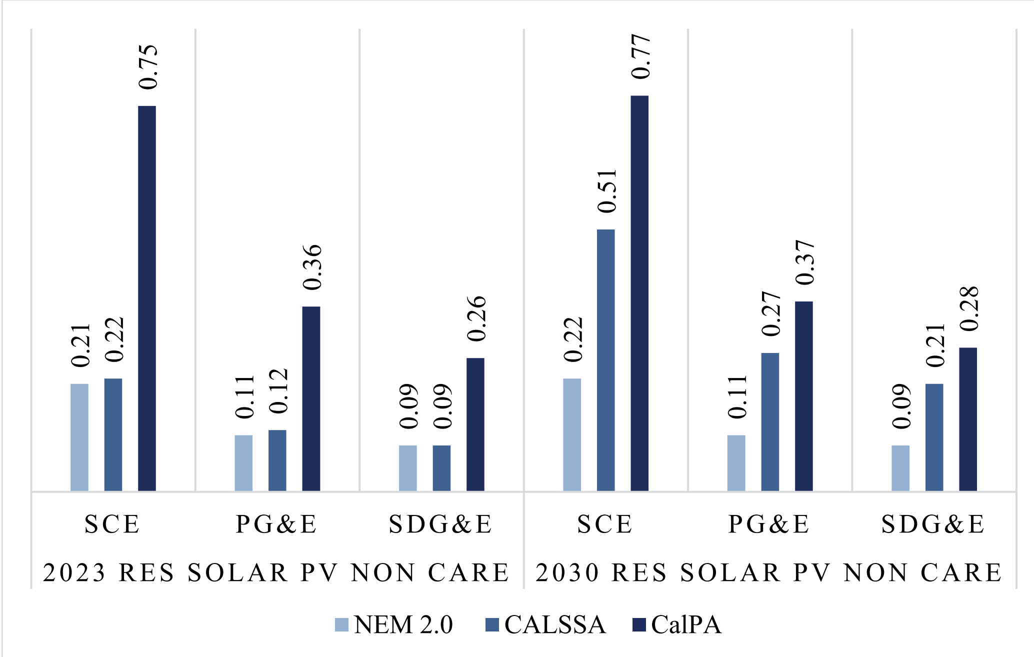

Figure 5-1 illustrates NEM 2.0 and CALSSA's low RIM score, while Cal Advocates' proposal meaningfully raises the RIM score.

Cal Advocates' proposed successor tariff results in a score less than one because it balances lowering the cost burden with the other statutory requirements, such as encouraging DERs to "grow sustainably"[483] and providing a "reasonable expected payback period."[484] E3 notes that all party proposal's result in a payback period longer than the NEM 2.0 payback period, and the dilemma of shortening payback periods results in a larger cost burden:

> Across the board, the proposals that have a shorter payback period also have a larger cost shift. This reflects the fundamental tension that exists between the solar adopter and the nonparticipant. Absent non-rate funds, utility cost recovery is essentially a 'zero sum game' and a tariff that

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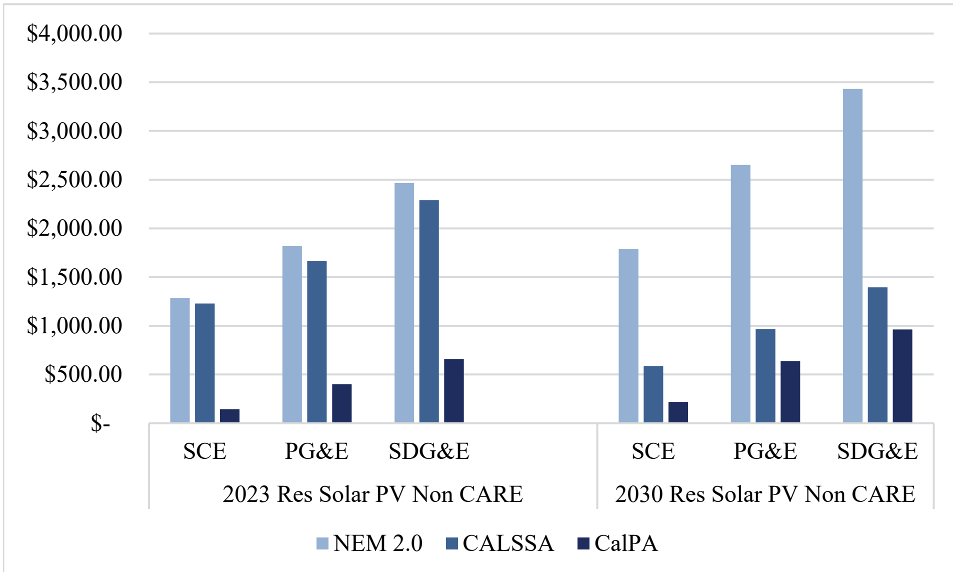
[483] Public Utilities Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

[484] Public Utilities Code § 2827.1(b)(6): "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."

> provides a shorter payback period for a solar adopter will result in a larger cost shift to the nonparticipant.[485]

Below in Figure 5-2, are the first-year cost burdens of the Cal Advocates Proposal compared to NEM 2.0 and CALSSA.

Figure 5-2: E3's 2023 and 2030 Successor Tariff First-Year Cost Shift Results for Residential Non-CARE Customers



Across all scenarios, the Cal Advocates proposal results in a more significant increase in RIM values, and thus, a larger decrease in first year cost burden compared to NEM 2.0 and CALSSA.[486] In order to align the successor tariff with guiding principle (b) ensuring program equity by reducing the cost burden, the successor tariff will ultimately need to have a longer payback period than NEM 2.0.[487] Cal Advocates' proposed successor tariff results in a significant decrease in the cost burden with a reasonable increase to the payback period. Cal Advocate's proposal works to incentivize solar paired with storage through a shortened payback period compared to stand alone storage.[488]

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[485] Cost-effectiveness Study, p. 2.

[486] Inclusive of CARE customer not graphed for ease of viewing.

[487] This is under the assumption that there is no funding from external non-ratepayer sources.

[488] Cost Effectiveness Study, pp. 34-35. Cal Advocates proposal results in a payback period of 12.5,16.5,

The Commission is required to review and consider the RIM test when it evaluates and selects successor tariff options.[489] The TRC test does not capture alterations in NEM tariff design, nor does it address equity concerns. In accordance with statute, the Commission must base the successor tariff on the costs and benefits of the renewable electrical generation facility.[490] Furthermore, the Commission's guiding principles for this proceeding set forth that a successor tariff should ensure equity among customers.[491] A proposal with a low RIM score does not inevitably leads to the cost burden falling on nonparticipants and thus does not take into account the equity of the successor tariff, as NEM systems are historically installed by white upper class homeowners.[492]

The TRC test, by design, cannot account for equity as it does not account for any costs passed on to customers who do not participate in NEM (nonparticipants). The TRC is designed to capture both the participant's (a customer with a NEM system installed) and the utility's costs of administering a program.[493] Instead of differentiating between "non-participants" and "participants," the TRC combines the two into a broader category of "ratepayers." Because of this generalization, any benefits to participants that come at the expense of nonparticipants is netted out of the test.[494] The TRC does not capture any impact that the NEM program has

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and 9.1 years for PG&E, SCE and SDG&E respectively for 2023 Non-CARE Residential Solar and a shortened payback period of 10.2,10.5, and 6.8 respectively for 2023 Non-CARE Residential Solar paired storage.

[489] D.19-05-019, Ordering Paragraph 2: "Beginning on July 1, 2019, all Commission activities, including filings and submissions, requiring cost-effectiveness analysis of distributed energy resources, except where expressly prohibited by statute or Commission decision shall also review and consider the results of the Program Administrator Cost test and the Ratepayer Impact Measure test. Determinations shall include a discussion of the other tests."

[490] Public Utilities Code 2827.1 (b) (3).

[491] D.21-02-007, OP 1 guiding principle (b), p. 45: "A successor to the net energy metering tariff should ensure equity among customers."

[492] Severin Borenstein, Rooftop Solar Inequity, Energy Institute at Haas, available at: https://energyathaas.wordpress.com/2021/06/01/rooftop-solar-inequity/.

[493] California Standard Practice Manual Economic Analysis of Demand Side Programs and Projects, (CA Standard Practice Manual) October 2001, p. 18.

[494] CA Standard Practice Manual, p. 21. "Since this test treats incentives paid to participants and revenue shifts as transfer payments *(from all ratepayers to participants through increased revenue requirements),* the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results" (emphasis added).

specifically on nonparticipants, such as the cost burden associated with NEM.[495] The TRC is a summation of the participant cost test[496] and the RIM test, thus revenue/bill changes to customers caused by the program is canceled out by incentives provided to the program.[497]

The RIM test should be used to capture the consequences of the successor tariff on nonparticipants to ensure it is equitably designed.[498] The RIM test is the only test to capture the cost burden for nonparticipants caused by NEM and therefore test for compliance with the guiding principle of equity.[499] To adequately evaluate the trade-offs inherent in customer-sited generation, the Commission must evaluate the successor tariff with the RIM test, with the inclusion of onsite energy consumption, to ensure that "wealthier than average" participants do not benefit from onsite consumption at the cost of nonparticipants.[500] Programs with RIM test

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[495] CA Standard Practice Manual, p. 18.

[496] CA Standard Practice Manual, p. 8. The Participant Test (commonly referred to as the Participant Cost Test) measures the benefits and costs to a customer due to participation in a program. The benefits are the reduction in utility bill, incentives received, and tax credits. The costs are the out-of-pocket expenses incurred to participate in program, such as the costs of the PV system, loan, PPA etc... Cost of rooftop solar has declined and is expected to continue to decline, which will show improvements in the PCT.

[497] The benefits used to calculate the TRC are the avoided supply costs and reduction in transmission, distribution, generation, and capacity costs. The costs in the TRC test are the expenses to procure a resource (e.g., the market cost of solar panels). The costs used to calculate the TRC are paid by both the IOU and the participants, including the increase in supply costs for the periods in which load is increased (all equipment costs, installation, operation and maintenance, cost of removal [less salvage value], and administration costs, no matter who pays for them, are included in this test). Thus, the TRC value is not impacted by changes in rate design or the tariff value. Any variations in TRC value among parties' proposals for their successor tariff design is solely caused by the lack of uniformity in assumptions in the calculation going into the model that each party has chosen to use. CA Standard Practice Manual, p. 18.

[498] The RIM test looks at participants' bill savings and at the impact on nonparticipants relative to what costs would have occurred without the program. The California Standard Practice Manual states that the benefits calculated in the RIM test are the savings from the avoided supply costs (including the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased). The costs calculated in RIM test are the utility/program administrator program costs, the incentives paid to the participant, and "decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." These costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The costs in the RIM test capture the decreased revenue of the IOU due to decreased load caused by bill savings (energy savings) by the program participants. CA Standard Practice Manual, p. 13.

[499] CA Standard Practice Manual, p. 14.

[500] Borenstein, S. Can Net Metering Reform Fix the Rooftop Solar Cost burden? See: https://energyathaas.wordpress.com/2021/01/25/can-net-metering-reform-fix-the-rooftop-solar-cost-shift/.

scores closer to 1.0 show that the programs result in minimal cost burdens to nonparticipants. The lower the RIM test score, the higher the cost burden associated with the program.[501] The NEM 2.0 Tariff has a RIM test score of 0.09, 0.11, 0.21 for SDG&E, PG&E and SCE respectively, indicating that NEM 2.0 creates a large cost burden for nonparticipants.[502] Decreasing the cost burden, and thus increasing the RIM test score to a value closer to 1, is necessary to ensure the successor program is equitable to ratepayers unable to participate in the successor tariff.

IV. CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF WOULD ENSURE SUSTAINABLE GROWTH

A. The Solar Industry Has a High Saturation and Costs Have, and Will Continue to Decline (S. Babka)

The current high NEM export rates were created when the rooftop solar industry was nascent and California policymakers wanted to subsidize solar adoption to transform the industry. Today, California leads the nation with the highest percentage of the state's electricity generated from solar at 22.69%.[503] When there were few customers with solar, the costs to nonparticipants were negligible. With the successful transformation of the industry, the Commission should update NEM to ensure the achievement of California's equity and environmental goals. The decline of costs associated with solar due to innovation and efficiency allows for the new NEM export rate to decrease without causing undue financial hardship to the solar industry.

Since the NEM tariff's original design, the cost of solar has decreased drastically and is expected to continue to decline, which will continue to promote installation rates and solar industry revenues. From 2009 to 2019, the cost of solar has decreased by more than 60% (from $8/W to $3/W).[504] This impressive reduction in costs can be heavily attributed to the declining

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[501] Lookback Study, p. 8. "RIM benefit-cost ratio less than 1.0 indicates the NEM 2.0 program will result in an increase in rates for all customers and an increase in bills for non-participating customers."

[502] Cost Effectiveness Study, p. 34 Results for Residential Solar, 2023 Non-CARE.

[503] SEIA, "California Solar", https://www.seia.org/state-solar-policy/california-solar. This number is not specified to be exclusive of solely rooftop solar, and NREL Q4 2019/Q1 2020 Solar Industry Update, slide 22 https://www.nrel.gov/docs/fy20osti/77010.pdf. In 2019 California had the highest penetration at almost 20% of generation.

[504] Energy Sage, "How Have the Solar Equipment Costs Declined Over Time?" See: https://news.energysage.com/how-have-solar-equipment-costs-declined-over-time/.

cost of the solar panels and inverters. The cost of solar panels decreased from $10/W in 1980 to $2/W in 2010, an 80% decrease over 30 years. An additional 50% decrease from 2015 to 2019 contributed to the current price of $0.35/W.[505] More recently, adjusting for inflation, residential photo-voltaic system costs have decreased by $0.06/W from Q1 2019 to Q1 2020.[506] The costs of solar are expected to decrease gradually into the future.[507]

Meanwhile, decreasing technology costs coupled with "value-stacking" policies, under which a NEM participant can receive compensation for providing grid benefits, allow the solar industry to maintain lucrative economics despite the lowering or fluctuation of NEM export compensation rates.[508] In addition to these new opportunities, the Federal Investment Tax Credit was recently extended,[509] increasing the value-proposition of solar installation by further shortening the potential pay-back period. Because costs of solar have decreased significantly since the commencement of the NEM program, the benefits of the successor tariff should reflect these changes.

As the US works towards cleaning its grid, the Department of Energy and Biden administration has set a goal to cut the cost of solar energy by 60% over the next decade to promote grid decarbonization by 2035 and has further committed $128 million in funding

[505] Energy Sage, "How Have the Solar Equipment Costs Declined Over Time?" See: https://news.energysage.com/how-have-solar-equipment-costs-declined-over-time/.

[506] NREL US Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, p. v. See: https://www.nrel.gov/docs/fy21osti/77324.pdf.

[507] Tracking the Sun: Pricing and Design Trends for Distributed PV Systems in the US – 2019 Edition, pp. 18-19. https://emp.lbl.gov/publications/tracking-sun-pricing-and-design. The installed price of solar declined sharply from 2009-2014 due to module price decrease, with a gradual decline in cost continuing. The decline in price has been dampened by higher customer acquisition costs as early adopters are converted, and by a greater emphasis on profitability by large installation firms.

[508] For example, the recent adoption of the Partnership Pilot in decision (D.)21-02-006 of the Integrated Distributed Energy Resources Proceeding allows for BTM generation resources under the NEM Tariff to be considered "fully incremental for the purposes of all DIDF procurement mechanisms… if the distributed energy resources provider makes a material enhancement to provide the utility-solicited deferral services." This decision allows NEM customers who fit the specified technology criteria to be compensated for providing grid services on an individual basis, providing direct valuation for a BTM generation system's contribution to deferring grid upgrades. SEIA/Wood Mackenzie Power and Renewables. *US Solar Market Insight 2020 Q4*. Accessed February 22, 2021. Available at https://www.seia.org/solar-industry-research-data.

[509] See: https://www.energysage.com/solar/cost-benefit/solar-investment-tax-credit/.

towards research aimed at a solar material cost decrease.[510] As the US moves in the direction of further renewable energy adoptions, the solar industry is expected to see long-term growth.[511]

The installed solar capacity in the US grew 43% in 2020 from 2019 levels for a record breaking capacity of 19.2 GWdc[512] installed.[513] Further demand for residential solar in California experienced a surge following the mandated power shutoffs due to the October 2019 wildfires, and Wood Makenzie expects events such as the fires to continue to drive customer interest in residential solar and solar plus storage.[514] In 2020, solar also accounted for 43% of all new electricity generating capacity added in the US, with residential deployment up 11% from 2019 levels, reaching a record level of 3.1 GW deployed.[515] Wood Mackenzie projects a cumulative 324GWdc of solar capacity additions over the next decade, further showing the solar industry will continue to grow in the US as reform continues state by state. Taking into account the uncertainties that California's reform of NEM will have on the industry, Wood Makenzie expects 10% national residential growth of solar in 2023.[516] As further efforts are made to

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[510] "US Pledges to Slash Solar Energy Costs by 60% in a Decade." March 25, 2021. See: https://www.usnews.com/news/top-news/articles/2021-03-25/us-pledges-to-slash-solar-energy-costs-by-60-in-a-decade#:~:text=(Reuters)%20%2D%20The%20Biden%20administration,cost%20target%20by%20five%20years.

"DOE Announces Goal to Cut Solar Costs by More than Half by 2030." See: https://www.energy.gov/articles/doe-announces-goal-cut-solar-costs-more-half-2030.

[511] The New York Times "*How Sustainable Is the Rally in Renewable Energy Stocks?"* See: *https://www.nytimes.com/2021/01/14/business/energy-environment/how-sustainable-is-the-rally-in-renewable-energy-stocks.html.*

Axios, Solar shares' spikes signal new energy landscape in D.C. See: https://www.axios.com/energy-landscape-dc-solar-8cea384b-99dd-4b97-9fe2-b150262a6f21.html

[512] GWdc refers to direct current.

[513] SEIA, Solar Market Insight Report 2020 Year in Review**:** The quarterly SEIA/Wood Mackenzie Power & Renewables U.S. Solar Market Insight™ report shows the major trends in the U.S. solar industry. Learn more about the *U.S. Solar Market Insight Report***.** Released March 16, 2021. https://www.seia.org/research-resources/solar-market-insight-report-2020-year-review, accessed March 21, 2021.

[514] Wood Makenzie US Solar Market Insight Executive Summary, p. 11.

[515] SEIA, Solar Market Insight Report 2020 Year in Review**:** The quarterly SEIA/Wood Mackenzie Power & Renewables U.S. Solar Market Insight™ report shows the major trends in the U.S. solar industry. Learn more about the *U.S. Solar Market Insight Report***.** Released March 16, 2021. https://www.seia.org/research-resources/solar-market-insight-report-2020-year-review, accessed March 21, 2021.

[516] Wood Makenzie US Solar Market Insight Executive Summary, p. 11.

decrease the costs of solar, incentives for solar should also decrease to keep electric rates affordable and on track to ensure electrification is accessible and affordable for all.

B. The California Solar Mandate Guarantees Growth for the California Solar Industry (A. Buchholz)

Title 24, section 6 of the California Energy Code, also known as the California Solar Mandate, requires solar panels on all newly constructed residential buildings up to three stories,[517] guaranteeing a steady customer stream for the solar industry. This mandate could drive 74,000[518] to 100,000[519] solar installations, and 444 to 600 MW[520] of residential rooftop capacity each year. Prior to this mandate going into effect, approximately 143,000 homes installed rooftop solar in 2019,[521] so the mandate could drive up to 70% growth[522] in the number of solar rooftops in California. With this mandate, the solar industry in California will see significant guaranteed sales over the coming years, ensuring sustainable growth in solar penetration regardless of how the Commission chooses to reform the NEM tariff. The successor tariff can be reformed to reflect this inevitability.

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[517] California Energy Code, Title 24 Part 6.

[518] E3's report to the California Energy Commission estimated 74,000 units per year, but only includes single-family homes, thus underestimating the total number of qualifying units. Measure Proposal Rooftop Solar PV Systems from the California Energy Commission's Title 24, Part 6, Building Energy Efficiency Standards Rulemaking, p. 48.

[519] The Federal Reserve Bank of St Louis indicates that 109,800 units were approved for construction in 2019 in California. It does not allow users to identify how many units are in buildings with four or more stories, thus providing an upper bound of around 100,000 qualifying units. 2019 was chosen as the reference year because the COVID-19 Pandemic may make 2020 non-representative of the norm. "New Private Housing Units Authorized by Building Permits for California." Federal Reserve Bank of St. Louis. See: https://fred.stlouisfed.org/series/CABPPRIVSA#0.

[520] DGStats indicates that the average solar installation in 2019 was approximately 6 kW. 74,000 * 6kW = 444 MW. 100,000 * 6kW = 600 MW. https://www.californiadgstats.ca.gov/

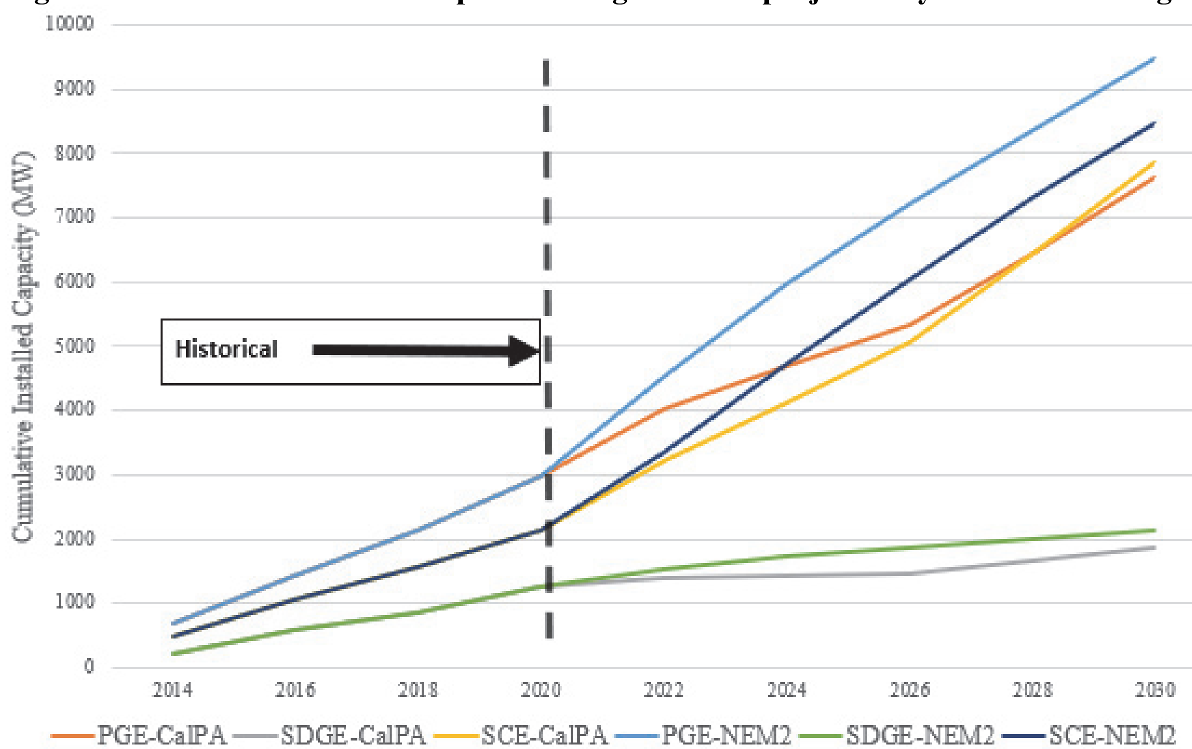
[521] Distributed Generation Stats. https://www.californiadgstats.ca.gov/. 2019 was chosen as the comparison year because 2020 may not be a valid comparison due to economic disruption by the COVID-19 pandemic.

[522] If most of the 143,000 installations in 2019 were not on newly constructed homes, the 100,000 annual installations will increase the number of annual BTM residential solar installations by 70%.

C. Models Show Continued Healthy Adoption of BTM Generation After Program Reform (A. Buchholz)

Modeling using the National Renewable Energy Lab's Distributed Generation Market Demand (dGEN) tool indicates that the solar industry would see continued growth under the Cal Advocates proposal. The dGEN tool is a "geospatially rich, bottom-up, market-penetration model that simulates the potential adoption of DERs for residential, commercial, and industrial entities in the continental United States."[523] Results from dGEN indicate that more than 5.6 GW of residential renewable capacity could be installed by 2030 under this proposed tariff (see figure 5-3).[524] This is in addition to installations driven by the California Solar Mandate. The dGEN tool results show that the solar industry would continue to see growth under the successor NEM tariff, indicating that the Commission can implement Cal Advocates' proposals and achieve the State's goals.

Figure 5-3. Residential NEM adoption through 2030 as projected by dGEN modelling.



[523] The Distributed Generation Market Demand Model (dGen) Documentation, p. 5. https://www.nrel.gov/docs/fy16osti/65231.pdf

[524] Note that this simulation used the same GBC values as those submitted for evaluation in E3's *Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking R.20-08-020*. Cal Advocates' GBCs as proposed in this document are slightly higher, but should not dramatically impact the results. Annual export compensation rates used the 2021 avoided cost calculator.

D. NEM Program Reform in Other States has Maintained Sustainable Solar Industries (S. Babka)

California's rooftop solar policy is lagging behind other states that have successfully implemented equity reform to NEM policies. Despite a multitude of states transitioning away from programs that compensate solar at full retail rates in 2020, solar represented the highest share of new capacity additions to the US electricity generation, more than any other resource.[525] For example, the Arizona Corporation Commission eliminated its retail rate (NEM) compensation structure for new rooftop solar customers in a December 2016 decision.[526] For new solar customers, the Arizona Commission replaced net metering with a Value of Solar tariff. The Value of Solar for each Arizona utility is decided through individual rate cases,[527] and can be set using a Five-Year Avoided Cost methodology, a Resource Comparison Proxy methodology or a combination of the two.[528] New solar customers of Arizona Public Service, for example, receive a 10-year flat rate for solar exports valued below the retail rate.[529]

According to data shown in Table 3 from the Solar Energy Industries Association (SEIA), residential solar (dark blue) installations did not decrease in response to the elimination of NEM and have continued at installation rates similar to the installations before the 2016 reform:

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[525] Solar Market Insight Report 2020 Year in Review, https://www.seia.org/research-resources/solar-market-insight-report-2020-year-review

DSIRE Net Metering June 2020 https://www.dsireusa.org/resources/detailed-summary-maps/

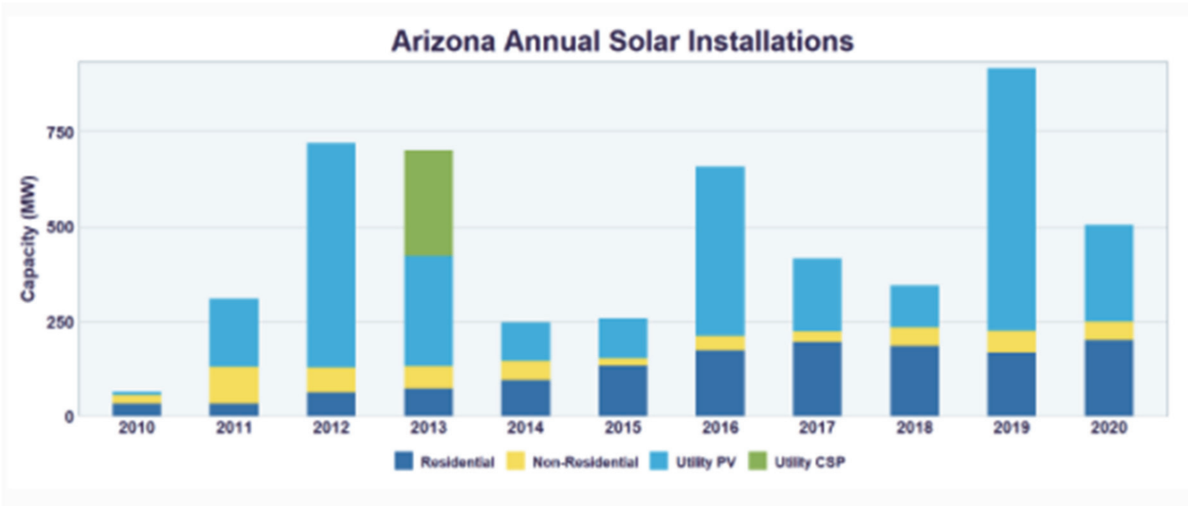
[526] Arizona Corporation Commission, Decision No. 75859, Docket E-00000J-14-0023, *In the matter of the Commission's Investigation of Value and Cost of Distributed Generation* (Arizona Decision 75859). https://docket.images.azcc.gov/0000176114.pdf, accessed September 26, 2019.

[527] Arizona Decision 75859, p. 176.

[528] Arizona Decision 75859, p. 177.

[529] See Sunrun, "Understanding Arizona's New Solar Export Rate Plan." https://www.sunrun.com/solar-by-state/az/understanding-arizonas-new-solar-export-rate-plan, accessed October 14, 2019.

Figure 3: Arizona Installation Capacity[530]



Arizona is not alone in reducing the cost of solar export compensation. In May 2021, the Kentucky Public Service Commission issued an order approving a new export compensation rate for NEM customers based on avoided costs (including the costs of generation, distribution and transmission capacity, energy, and ancillary service costs and avoided environmental costs), resulting in a compensation rate of $0.09746/kWh.[531]. Since other states have successfully modernized their NEM policies, this additional evidence suggests that the Commission can institute NEM policy reforms identified in this document and achieve required statutory and state goals.

NEM reform is even occurring in California. On May 18, 2021, SMUD proposed a successor to its solar and storage rate and programs.[532] SMUD's proposal works to promote grid reliability through the creation of a "Virtual Power Plant Partnership Incentive" program, in which customers receive varying increases in incentive levels from SMUD for paired storage

[530] SEIA, "Arizona Solar." https://www.seia.org/state-solar-policy/arizona-solar, accessed May 21, 2021.

[531] News Release PSC Issues Order on Net Metering Tariff in Kentucky Power Rate Case, pp. 1-2. https://psc.ky.gov/agencies/psc/press/052021/0514_r01.pdf

[532] SMUD, "SMUD 2021-2022 Rate Proposal overview, including proposed rate increases and new Solar and Storage Rate and programs," May 18, 2021. See: https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2021/May/2021-05-18-Finance-and-Audit-Exhibit-to-Agenda-Item-1---Jennifer-Davidson-and-Eric-Poff.ashx.

systems that participate in different grid reliability export compensation programs.[533] The proposed compensation for SMUD customers' NEM exports are set at $0.074/kWh and determined by the avoided cost of generating the power from a powerplant and included the avoided cost of carbon, natural gas, capacity (transmission, distribution, & generation), and land use.[534]

V. CAL ADVOCATES' PROPOSED SUCCESSOR TARIFF ALIGNS WITH STATE AND COMMISSION GOALS

A. The Assumed Amount of Rooftop Solar Included in the Integrated Resource Plan Models Is Not Required for Meeting Climate Goals (A. Buchholz)

Some parties in their March 15, 2020 policy proposals pointed to rooftop solar deployment levels in IRP models as indication that California requires a specific amount of rooftop solar for to reach its RPS targets. This argument rests on those deployment numbers being an output, rather than an input, of the IRP models. The numbers these parties used in their arguments to are based on projections of adoption rates,[535] and the projected amount of rooftop solar is not actually required to meet California's renewable targets.

Indeed, the 2017-2018 Proposed Reference System Plan found that high amounts of BTM PV may *increase* overall system costs.[536] While later Reference System Plans do not include this sensitivity analysis, it is worth noting that rooftop solar is not guaranteed to reduce total costs.

IRP models do not require a specific amount of distributed solar to reach targets, so the Commission can reform NEM without endangering California's renewable goals.

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[533] SMUD, "SMUD 2021-2022 Rate Proposal overview, including proposed rate increases and new Solar and Storage Rate and programs," May 18, 2021. See: https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2021/May/2021-05-18-Finance-and-Audit-Exhibit-to-Agenda-Item-1---Jennifer-Davidson-and-Eric-Poff.ashx. Slide 36.

[534] SMUD, "SMUD 2021-2022 Rate Proposal overview, including proposed rate increases and new Solar and Storage Rate and programs," May 18, 2021. See: https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2021/May/2021-05-18-Finance-and-Audit-Exhibit-to-Agenda-Item-1---Jennifer-Davidson-and-Eric-Poff.ashx. Slide 39.

[535] See 2019-2020 Integrated Resource Planning Inputs and Assumptions, p. 11.

[536] 2017-2018 Proposed Reference System Plan, p. 78.

B. Cal Advocates' Proposed Successor Tariff Removes Barriers to Achieving State Electric Vehicle Goals (K. Rounds)

Cal Advocates demonstrates the cost burden impacts associated with the current NEM tariff throughout this Testimony and provides evidence as to how the tariff could negatively impact other electrification measures throughout the state. Regarding Transportation Electrification (TE) specifically, we have pointed to the negative relationship between high electricity rates and EV adoption and addressed the impact of the current NEM tariff in increasing electricity rates.[537] To reiterate the findings of the Davis Energy Economic Program at the University of California, Davis, "[e]ach $0.10/kWh increase in electricity prices" results in a "15% decrease in EV demand" (in terms of EV miles driven).[538] To stay aligned with California's transportation electrification goals, specifically those outlined in Assembly Bill 841 which mandates equity targets in TE programs,[539] it will be critical to address the regressive rate-making practices under NEM to preserve affordability in electricity rates. Cal Advocates' proposal focuses on mitigating the existing cost burden caused by NEM and transitioning to more economically efficient electricity pricing, which in turn will aide in incentivizing EV adoption by putting downward pressure on customers' electric rates.[540] Affordable electricity rates are critical for the success of statewide TE programs, and equitable NEM reform is a necessary step in this process.

C. Cal Advocates' Proposed Successor Tariff Would Help Achieve State Microgrid Goals (K. Rounds)

Cal Advocates' NEM proposal aligns with the state's microgrid commercialization goals. Senate Bill (SB) 1339 requires the CPUC, the California Energy Commission (CEC), and CAISO to facilitate "the commercialization of microgrids for distribution customers of large electrical corporations" through the development of guidelines, rules, and policies that reduce

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[537] See Chapter 2, Section I.B of this proposal for detailed analysis.

[538] *En Banc on Energy Rates and Costs*. February 24, 2021. California Public Utilities Commission. Slide 36. Available at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_PANEL%201_Updated.pdf

[539] A.B. 841, Ting, Chapter 372, Statutes of 2020. Accessible at https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_id=201920200AB841

[540] See Chapter 2, Section I.B of this proposal for detailed analysis.

barriers to deployment of microgrids without shifting costs between ratepayers.[541] Solar plus storage systems under Cal Advocates' proposed NEM tariff would fulfill this mandate, and any resiliency benefits provided by these systems will be valued through the mechanism decided upon by the Commission in R.19-09-009.[542]

D. Cal Advocates' Proposed Successor Tariff Would Help Achieve State Building Decarbonization Goals (A. Ward)

California's existing buildings account for nearly a quarter of the state's GHG emissions.[543] A substantial portion of these building emissions are driven by the burning of gas for space and water heating. Space and water heating collectively amount to nearly two thirds of a typical home's energy consumption,[544] and nearly 90% of California homes use natural gas for one or both.[545] Electrification of buildings is therefore particularly important in achieving the State's GHG emissions reductions goals. The Commission has recognized the importance of building electrification in its proceeding on building decarbonization, through which it has established pilot programs incentivizing, among other things, electric space and water heating.[546]

However, electrification of buildings relies on reasonable electricity rates to avoid placing significant burdens on customers whose electricity usage will increase as they replace their gas-powered appliances. Since 1950, 82% of home electrifications have been driven by lowering electrical rates and rising natural gas and heating oil rates across the country.[547] As

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[541] Senate Bill 1339, Stern, Chapter 566, Statutes of 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1339

[542] Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339. Filed September 12, 2019. California Public Utilities Commission. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF

[543] Final 2019 Integrated Energy Policy Report, p. 44. Adopted February 20, 2020. California Energy Commission. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

[544] Energy Use in Homes. Last updated August 4, 2020. US Energy Information Administration. Available at https://www.eia.gov/energyexplained/use-of-energy/homes.php.

[545] Fuels Used and End Uses in Homes, Residential Energy Consumption Survey. US Energy Information Administration. Available at https://www.eia.gov/consumption/residential/data/2009/xls/HC1.11%20Fuels%20Used%20and%20End%20Uses%20in%20West%20Region.xls.

[546] *See* Order Instituting Rulemaking Regarding Building Decarbonization (Rulemaking 19-01-011). Filed January 31, 2019. California Public Utilities Commission.

[547] Lucas Davis, Energy Institute at Haas, "What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices," April 2021, pp. 2-3.

discussed in Chapter 2, rising electricity rates make the value proposition of fuel switching less attractive to customers. NEM's contribution to rising rates exacerbates the already-high barriers to the widespread building electrification needed to achieve California's climate goals. Cal Advocates' proposed NEM tariff would support building electrification by moderating these rate increases and should therefore be adopted.

E. Cal Advocates' Proposed Successor Tariff Would Help Achieve State Equity Goals (A. Buchholz)

This proposal is aligned with the CPUC's environmental and social justice action plans. The second goal of this action plan is to "[invest] in clean energy resources to benefit environmental and social justice communities, especially to improve local air quality and public health."[548] This proposal, particularly the equity fee, directly addresses this important goal by encouraging adoption by low-income ratepayers and residents of disadvantaged communities.

F. The Distribution Resources Planning Process Determines the Best Location for BTM Generation on the Grid (K. Rounds)

Cal Advocates recognizes the benefits that can be provided to the distribution grid through DER installations. These benefits are rigorously quantified and specified[549] through the Distribution Resources Planning Process in R.14-08-013 and valued through the framework set forth in R.14-03-003 (IDER Proceeding). DER installations that have been vetted and selected through the Distribution Investment Deferral Process to meet distribution system needs as an alternative to utility infrastructure investments are compensated for their services to the grid under the Competitive Solicitation Framework process or the five-year DER distribution deferral Partnership Pilot tariff adopted in the Principles Decision. As such, the new NEM tariff should not seek to value the grid services that are already compensated through these processes.

Cal Advocates' utilization of the ACC in this NEM tariff proposal adequately captures the unspecified[550] benefits provided by DER installations that are not participants of the DER tariff set forth in the Integrated Distributed Energy Resources proceeding. If developers of NEM systems believe their installations can contribute to the specific grid needs identified within the Distributed Resource Planning proceeding (R.14-08-013), they may participate in the distribution

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548 Environmental and Social Justice Action Plan, Goal 2. https://www.cpuc.ca.gov/esjactionplan/

549 See more detail on unspecified versus specified distribution costs in Chapter 3 of this Testimony.

550 See more detail on unspecified versus specified distribution costs in 3 of this Testimony.

deferral process to obtain compensation for those services. Cal Advocates' proposed NEM tariff defers the determination of the optimal location for BTM generation to these proceedings and does not attempt to socialize unspecified distribution benefits across ratepayers outside of those calculated with the ACC.

CHAPTER 6 IMPLEMENTATION TIMELINE

(Witness: Alec Ward)

The Commission should reform the existing NEM tariffs as quickly as possible, in the timeline specified below. The current limitations of the existing NEM tariff threaten the timely achievement of the state's climate and equity goals and must be addressed immediately.

While California should be leading the adoption of cost-effective, equitable DER policy, it currently lags behind other states.[551]

The Commission should take the lead again by adopting a sustainable and equitable NEM tariff as quickly as possible. ALJ Hymes emailed parties on April 4, 2021, stating a proposed decision determining the major aspects for a successor tariff will be released no later than December 9, 2021, with a Commission decision at least a month afterwards.[552] Cal Advocates does not propose multiple implementation phases for the successor tariff because it would further delay NEM modernization and would be unnecessary. Instead, the IOUs should file advice letters within 3 months of a Commission decision to implement the proposed policy reforms. Through this process, the IOUs should be able to begin enrolling new customers on the successor tariff by April 8, 2022, depending on the timing of the Commission decision.

The successor should be implemented quickly, as Chapter 5 of this Testimony details the strong DER industry and ensured growth for years to come through state mandates and incentive programs. For this reason, and due to NEM's misalignment with state climate and equity goals, the Commission should not adopt a glidepath stepping down tariff compensation or fees between NEM 2.0 and the successor tariff. Any customer that signs up for NEM 2.0 in 2022 before the successor tariff is implemented should be notified that they will be automatically switched to the successor tariff once it begins accepting applicants. If the Commission chooses to adopt Cal Advocates' policy proposal incenting NEM 1.0 and 2.0 customers to transition to the successor tariff, all NEM 1.0 and 2.0 customers should be transitioned to the successor tariff no later than five years after the Transition Incentive Program begins.[553]

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[551] See Chapter 5 of this Testimony for examples of NEM reform.

[552] Email from ALJ Kelly A. Hymes to R.20-08-020 Service List, "R.20-08-020 Email Ruling Noticing April 22, 2021, Workshop and Revising Procedural Schedule," April 4, 2021.

[553] See Chapter 4 for Transition Incentive Program details.

As noted in Chapter 1 of this Testimony, while Cal Advocates' proposed successor tariff would meaningfully reduce the current NEM cost burden, approximately 50% of the successor tariff cost burden and 39 to 62% of the NEM 1.0 and 2.0 cost burdens would remain. This is because Cal Advocates' successor tariff proposal balances reducing the cost burden with the other statutory requirements, such as ensuring that DERs must "grow sustainably"[554] and the Commission must provide a "reasonable expected payback period."[555] To ensure the successor tariff remains aligned changing electricity rates, laws and policies, DER markets, or other variables, the Commission should comprehensively review the successor tariff after five years following its implementation and maintain the ability to create and transition current successor tariff customers to an updated tariff.

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[554] Public Utilities Code § 2827.1(b)(1): "Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

[555] Public Utilities Code § 2827.1(b)(6): "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."

APPENDIX A

QUALIFICATIONS OF WITNESSES

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ALEC WARD

Q.1 Please state your name and business address.

A.1 My name is Alec Ward. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electrical Pricing & Customer Programs Branch of the Public Advocates Office.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Master of Science in Environmental Science and Policy from Johns Hopkins University, and a Bachelor of Arts in History and American Government from the University of Virginia. I joined the Electrical Pricing & Customer Programs Branch in December 2019.

Q.4 What is the scope of your responsibility in this proceeding?

A.4I was responsible for preparing Chapter 1, Chapter 2.I, Chapter 2.III, Chapter 3.I, Chapter 4.I, Chapter 5.V.I, and Chapter 6 of Public Advocates Office's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
KRISTIN ROUNDS

Q.1 Please state your name and business address.

A.1 My name is Kristin Rounds. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Energy Infrastructure Branch of the Public Advocates Office.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Master of International Affairs with a specialization in Energy and Environmental Policy from the University of California San Diego, and a Bachelor of Arts in Political Science from California State University Chico. I joined the Energy Infrastructure Branch in October 2020.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I was responsible for preparing Chapter 3.III, Chapter 5.V.G, Chapter 5.V.H, and Chapter 5.V.K of Public Advocates Office's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
SOPHIE BABKA

Q.1 Please state your name and business address.

A.1 My name is Sophie Babka. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electrical Pricing & Customer Programs Branch of the Public Advocates Office.

Q.3 Briefly state your educational background and experience.

A.3 I have a Bachelor of Science in Environmental Sciences and minors in Public Policy and Energy Resources from the University of California, Berkeley. I am employed as a Public Utilities Regulatory Analyst in the Customer Branch of the Public Advocates Office. I have been working for the Public Advocates Office since November 2019, and previously worked in the Energy Division of the California Public Utilities Commission (Commission). I have worked on the following Commission proceedings, Ordering Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs (R.18-07-005), Order Instituting a Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service (R.18-07-006), Order Instituting a Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues (R.13-11-005), Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering (R.14-07-002) and Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering (R.20-08-020).

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I was responsible for preparing Chapter 2.I.C, Chapter 5.I Chapter 5.III, Chapter 5.IV.A, and Chapter 5.IV.D of Public Advocates Office's testimony. I was responsible for preparing

Q.5 Does this complete your testimony at this time?

A.5 Yes, this completes my prepared testimony.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ADAM BUCHHOLZ

Q.1 Please state your name and business address.

A.1 My name is Adam Buchholz. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electrical Pricing & Customer Programs Branch of the Public Advocates Office.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Masters of Public Policy from the University of California at Berkeley's Goldman School of Public Policy, and a Bachelor of Arts in Biology from Pomona College. I joined the Electrical Pricing & Customer Programs Branch in December 2020.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I was responsible for preparing Chapter 2.II.A-D, Chapter 3.III, Chapter 3.VI, Chapter 5.III, Chapter 5.IV.B, Chapter 5.IV.C, Chapter 5.V.A, Chapter 5.V.E of Public Advocates Office's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
NATHAN CHAU

Q.1 Please state your name and business address.

A.1 My name is Nathan Chau, and my business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I work in the Electricity Pricing and Customer Programs Branch of the Public Advocates Office as a Regulatory Analyst.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Bachelor of Science degree in Applied Economics from the University of the Pacific. My degree included coursework in finance, economics, and econometrics that I find relevant to this case. Since joining the Commission in April 2015, I have actively participated in a number of rate cases such as SDG&E's General Rate Case Phase II (A.15-04-012), PG&E's General Rate Case Phase II (A.16-06-013), the Time-of-Use Order Instituting Rulemaking (R.15-12-012), and the Residential Rate Reform proceeding (R.12-06-013). I also served testimony in Phase 2A, Phase 2B and Phase 3 of SDG&E's A.17-12-013 Rate Design Window. I acted as project lead and served testimony in PG&E's General Rate Case Phase II (A.19-11-019).

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I was responsible for preparing Chapter 2.I.A, Chapter 2.I.B, Chapter 3.IV, 3.V.B, Chapter 3.VII, and Chapter 5.II of Public Advocates Office's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, this completes my prepared testimony.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
BEN GUTIERREZ

Q.1 Please state your name and business address.

A.1 My name is Ben Gutierrez, and my business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the Public Advocates Office at the California Public Utilities Commission, and I work in the Electricity Pricing and Customer Programs Branch, Electricity Pricing section, as a Regulatory Analyst.

Q.3 Briefly state your educational background and experience.

A.3 I graduated from Harvard University, Cambridge, MA with a Bachelor of Arts in Environmental Science and Public Policy. I have been employed by the Public Advocates Office for five years. In my experience at the CPUC I have worked on marginal costs and residential rate design for customers with distributed energy resources in San Diego Gas and Electric Company's (SDG&E) 2016 General Rate Case Phase II, Pacific Gas and Electric Company's (PG&E) 2017 GRC Phase II, and Southern California Edison Company's (SCE) 2018 GRC Phase II. I have also submitted testimony on electric vehicle rate design and cost allocation in the Transportation Electrification (TE) proceeding (A.17-01-020 et al.), SDG&E's Medium- and Heavy-Duty TE application (A.18-01-012), SCE's Charge Ready 2 application (A.18-06-015), PG&E's Commercial EV Rates proceeding (A.18-11-003), SDG&E's Electric Vehicle Higher Power (EV-HP) charging rate application (A.19-07-006), and PG&E's application for a Day-Ahead Real-Time Pricing (DAHRTP) electric vehicle pilot (A.20-10-011). Prior to working for the Public Advocates Office, I worked as a Clean Energy Coordinator and Philanthropy Coordinator for two years for the Malaysian nonprofit organization Land Empowerment Animals People (LEAP). This entailed performing resource assessments and cost analyses of clean energy and fossil fuel technologies, among other duties.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I was responsible for preparing Chapter 2.I.A, Chapter 2.I.B, Chapter 3.II.A, Chapter 3.II.B, Chapter 3.IV, Chapter 3.V.A, 3.V.B, Chapter 3.VII, Chapter 4.II, and Chapter 5.II of Public Advocates Office's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

APPENDIX B

LIST OF ACRONYMS

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LIST OF ACRONYMS

Acronym	Description
AB	Assembly Bill
ACC	Avoided Cost Calculator
ALJ	Administrative Law Judge
BTM	Behind the Meter
CAISO	California Independent System Operator
CARE	California Alternative Rates for Energy
CEC	California Energy Commission
CSGT	Community Solar Green Tariff
D.	Decision
DACs	Disadvantaged Communities
DAC-GT	Disadvantaged Communities Green Tariff
DAC-SASH	Disadvantaged Communities - Single-family Solar Home
DER	Distributed Energy Resource
E3	Energy and Environmental Economics, Inc.
ECR	Exports compensation rates
EV	Electric vehicle
FERA	Family Electric Rate Assistance
GBC	Grid Benefits Charge
GHG	Greenhouse gas
GRC	General Rates Case
HE	Hour Ending
IOUs	Investor-owned utilities
IRP	Integrated Resource Planning
ITC	Investment Tax Credit
kWh	Kilowatt-hour
NBCs	Non-bypassable charges
NPV	Net Present Value
NEM	Net Energy Metering
PG&E	Pacific Gas and Electric

Acronym	Description
PV	Photovoltaic
R.	Rulemaking
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SOMAH	Solar on Multifamily Affordable Housing
TRC	Total Resource Cost test
TOU	Time of Use

APPENDIX C

PROPOSALS FROM OTHER PARTIES

APPENDIX C
PROPOSALS FROM OTHER PARTIES THAT ALIGN WITH CAL ADVOCATES' PROPOSAL

	Cal Advocates	NRDC	Coalition of California Utility Employees (CUE)	The Utility Reform Network (TURN)	California Wind Energy Association (CalWEA)
Net Billing	X	X	X	X	X
Grid Benefits Charge	X	X	X	X	X
Equity Charge	X	X			X
Storage Rebate for NEM 1.0 and 2.0 Transition	X	X			
Upfront Incentives	X	X	X	X	X