Proceeding No.:	R.20-08-020
Exhibit No.:	Joint-01
Witnesses:	A. Bernhardt
	C. Kerrigan
	B. Kopec
	R. Madsen
	M. McCutchan
	E. Molnar
	G. Morien
	C. Peterman
	P. Thomas
	R. Thomas
	A. Pierce
	S. Tierney
	S. Wray
	M. Wright

R.20-08-020 Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Metering

Joint Opening Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles

Before the

Public Utilities Commission of the State of California

Rosemead, California
June 18, 2021

Joint-01: Joint Opening Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles

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I.

BACKGROUND AND INTRODUCTION

A. Overview of our position and introduction to the filing

For the past 25 years, California's net-energy metering (NEM) program has subsidized customers who install distributed energy resources (DERs), particularly solar generating facilities, on their premises. The subsidies are, in effect, transfer payments to customers who install rooftop solar generation and the subsidies are generally referred to as the "cost shift." Customers who do not have rooftop solar generation pay for these subsidies. The NEM program was designed to stimulate a nascent market and, by any measure, has succeeded at that goal. The current design is unnecessary to develop what is now a mature, not start-up, market. In 2013, the legislature directed the Commission to reform the existing NEM program going forward, but today the cost shift exceeds $3.4 billion annually. The Commission must also engage in serious and urgent reform because the current program design is unsustainable, and the program now undermines – rather than serves – the state's decarbonization goals by making electrification more expensive.

A reformed tariff should provide a sustainable structure for the future. It should ensure that customers have choices, that those choosing to install on-premises distributed generation[1] equipment are responsible for their appropriate share of the costs of the electricity service they receive, that they are fairly compensated for their exports of energy, that incentives focus on those who most need them (*i.e.*, income-qualified customers), and that both rate design and programs pivot the market toward increased adoption of paired solar and storage systems going forward.

1. The current NEM structure is not sustainable

The current NEM program (often referred to as NEM 1.0 and NEM 2.0) compensates participating customers for exports of energy at or near the host utility's retail rate. This compensation

[1] As used in this testimony, the term "distributed generation" ("DG") refers to generation technologies sited on the customer-side-of-the-meter, primarily designed to offset customer load, that produce renewable energy as defined in paragraph (1) of subdivision (a) of Section 25741 of the Public Resources Code and in the California Energy Commission's (CEC's) Renewables Portfolio Standard (RPS) Eligibility Guidebook and the Overall Program Guidebook. This includes storage that is charged by such a renewable generation technology.

rate is too high — much higher than what the utilities pay for power from other sources. The retail rate includes many costs the utility incurs to serve these customers' loads and that are not avoided when NEM customers generate power from their rooftop solar panels. NEM customers do not provide the other services associated with these extra costs and thus the retail rate significantly exceeds the value of the generated energy.

In addition, because NEM customers intermittently serve their own load they avoid paying their share of costs even though they use the grid every hour of every day. NEM customers continue to use the grid not only because their systems generate and supply energy intermittently, but also to export excess power they generate and to receive electricity when there is no power being generated on their roofs.[2]

The costs avoided by NEM customers include costs to maintain and improve or modernize the grid, and public purpose programs such as energy efficiency and income-qualified discounts. When NEM customers avoid these costs, they must be absorbed by everyone else. Thus, those costs are shifted to non-participating customers. This approach to subsidizing distributed renewable generation was defensible when there was a small amount of NEM generation on the grid, but given the popularity and success of the NEM program, the amount shifted is now more than $3.4 billion annually (An increase of approximately $245 a year for average San Diego Gas & Electric Non-CARE residential customers, where rooftop solar penetration is the highest) and will be closer to $10.7 billion per year (~$555 per year per average residential Non-CARE customer in SDG&E's service area) by 2030.[3]

Moreover, the impact of the subsidies built into the current NEM program is particularly troubling: NEM customers are predominantly higher income, while the nonparticipating customers

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[2] Some advance a false equivalence by attempting to analogize NEM customers serving their own load and customers who install energy efficiency appliances. Unlike customers who reduce load by installing a new energy efficient fixture, NEM customers do not permanently reduce their load. Instead, NEM solar customers intermittently reduce load depending on the performance of the solar panels. Also, depending on the performance of the solar panels, NEM customers export energy, requiring grid service that energy efficiency measures do not.

[3] For PG&E, the average annual bill impact on Non-CARE non-participants is $170 today and $505 in 2030. For SCE, the average annual bill impact on Non-CARE non-participants is $115 today and $385 in 2030.

absorbing the cost of the NEM subsidy are disproportionately lower-income customers.[4] Not only are the subsidies provided to more advantaged customers, but the subsidies are also significantly larger than those provided to our income-qualified customers to assist them with their electricity bills. As explained further in Chapter 3, the current NEM cost shift is now over 2.4 times the amount of the annual electric California Alternate Rates for Energy (CARE) subsidy provided to income-qualified customers. In SDG&E's service territory, the NEM cost shift is now nearly 5 times the amount of the annual electric CARE subsidy provided to customers. Even worse, while the NEM cost shift is multiples above the CARE subsidy, the number of customers in need of assistance through the CARE program is significantly higher than the number of NEM customers. This extreme misalignment is another example that compensation to rooftop solar customers is in desperate need of reform.

In inequitably distributing costs and benefits, the NEM program also undermines California's decarbonization goals. California anticipates transitioning non-electric energy consumption to electric energy consumption (e.g., gasoline or diesel vehicles to electric vehicles, gas heating and cooling to electric heating and cooling). By raising electricity rates, the current NEM program makes this transition more expensive for non-NEM customers and, in some cases, may dissuade them from making the necessary transition.

NEM also creates grid operation issues and stifles innovation. NEM fails to provide appropriate incentives for pairing storage with rooftop solar or for utility or aggregator control, thus making reliable grid operations more challenging and more expensive. In fact, because the NEM program is so lucrative for NEM customers, there is no incentive for more innovative uses of behind-the-meter technologies, such as participating in the wholesale market. In other words, why develop a mechanism to bid into the CAISO market when you can receive full retail compensation for simply delivering as-available generation?

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[4] California Public Utility Commission's report, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues pursuant to P.U. Code Section 913.1," February 2021, page 28. *See also* Chapter 3, below.

Finally, the NEM program runs fundamentally counter to the Commission's ratemaking principles:[5] that rates must be affordable, based on marginal-cost and cost-incurrence principles, generally avoid cross-subsidies, and encourage reduction in peak demand and economically efficient decision-making.

2. The current NEM structure is no longer needed

Since the NEM program began in 1995, the cost to manufacture and purchase solar panels and energy storage has significantly declined and will continue to decline, even without the NEM subsidy. Solar has continued to grow in other parts of the country where reform has occurred. There is no reason the same should not be true in a place like California, where solar is particularly appealing because of the weather and the environmental consciousness of the public. The solar industry's maturity is also evidenced by its innovative service offerings, the ability to adapt to changing conditions, and an outlook for growth in the California market.

Also, the NEM program is now no longer the only California subsidy for solar. California now has numerous policies and programs that support the solar market and drive customer-sited solar adoption, including a new regulation that mandates that new residential construction of buildings three stories and under in California must be built with a behind-the-meter (BTM) solar system.[6]

The state is also able to realize its important and ambitious climate goals—which we support—through a variety of endeavors and resources, including the building of large, utility-scale renewable resources and utility-scale energy storage facilities. The costs of these facilities are equitably absorbed by all customers and are significantly less expensive overall and per customer than the NEM subsidy. Sound policy will allow an optimized portfolio of distributed solar and distributed storage, as well as large scale resources, to contribute to California's policy goals.

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[5] R.12-06-013, at 27-28.

[6] As of January 1, 2020, California's Building Energy Efficiency Standards, Title 24, Part 6, of the California Code of Regulations governing California Building Standards, requires that all new residential buildings three stories and under that are built in the state to have solar panels.

3. Testimony Organization

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (collectively "we", "our", or the "Joint Utilities") have jointly developed a Reform Tariff proposal that will eliminate the NEM cost shift (except on a transitional basis for lower-income customers) and create incentives for solar-paired storage. We urge the Commission to approve it. Our testimony provides the bases for that recommendation.

This Chapter 1 of our testimony describes California's success in the deployment of rooftop solar, the role of NEM and other policies in delivering those outcomes in our state, problems with the current NEM design, our proposal to address them, and the criteria the Commission should use in considering NEM proposals in this proceeding.

Chapter 2, sponsored by Dr. Susan Tierney of Analysis Group, provides context for the issues the Commission is considering here. The chapter describes NEM policy adoption in other states, including ones that have reformed their tariffs; trends in the costs of solar and residential storage; consumers' motivations and preferences for utility service; the outlook for the solar and storage markets in and out of California; and key policy design principles the Commission should consider in assessing the proposals for NEM reform.

Chapter 3 details the cost shift arising from the current NEM program and describes the results of the Commission's cost-effectiveness tests.

Chapter 4 describes our core and income-qualified proposals for the new distributed generation successor tariff (Reform Tariff or DG-ST), proposals for virtual NEM (VNEM), and the "Value of Distributed Energy" (VODE) Tariff. The chapter also presents other elements of the proposed non-residential successor tariff.

Chapter 5 presents our proposal for lower income customers including the "Savings Through Ongoing Renewable Energy" (STORE) program, which will increase access to energy storage systems for income-qualified customers.

Chapter 6 explains how we plan to implement a new tariff, concerning timing, interconnection, billing, marketing/education/outreach, and consumer protection issues.

Chapter 7, also sponsored by Dr. Susan Tierney, provides an assessment of our proposal against CPUC criteria and other policy lenses including how it aligns with and fulfills the Commission's Guiding Principles adopted in D.21-02-007.

B. <u>We have supported rooftop solar and other renewable resource development</u>

We have proudly supported California's successful efforts to advance the state's renewable and low-carbon energy goals, including through our implementation of the NEM program, which served an important market development purpose at a specific time. For instance, we have been active players in helping our customers decide to "go solar." We have developed useful and accessible guides for helping customers understand solar options and the steps involved with putting solar on their rooftops, for locating and choosing contractors, for estimating the cost of installing solar and what it might mean for their electricity bills and for directing them to resources that will help them know their rights as consumers.[7] We have established efficient and accessible processes to safely interconnect solar customer facilities.

As part of our responsibility to deliver safe and secure power to the customers on our distribution system and to supply 60% of California's retail electricity sales,[8] we have safely interconnected significant volumes of BTM renewable resources - primarily solar photovoltaic (PV) rooftop solar systems - on our customers' premises. To date, the utilities have interconnected 9,920 MW of NEM rooftop solar customer capacity across our three service territories: 5,092 MW by PG&E; 3,332 MW by

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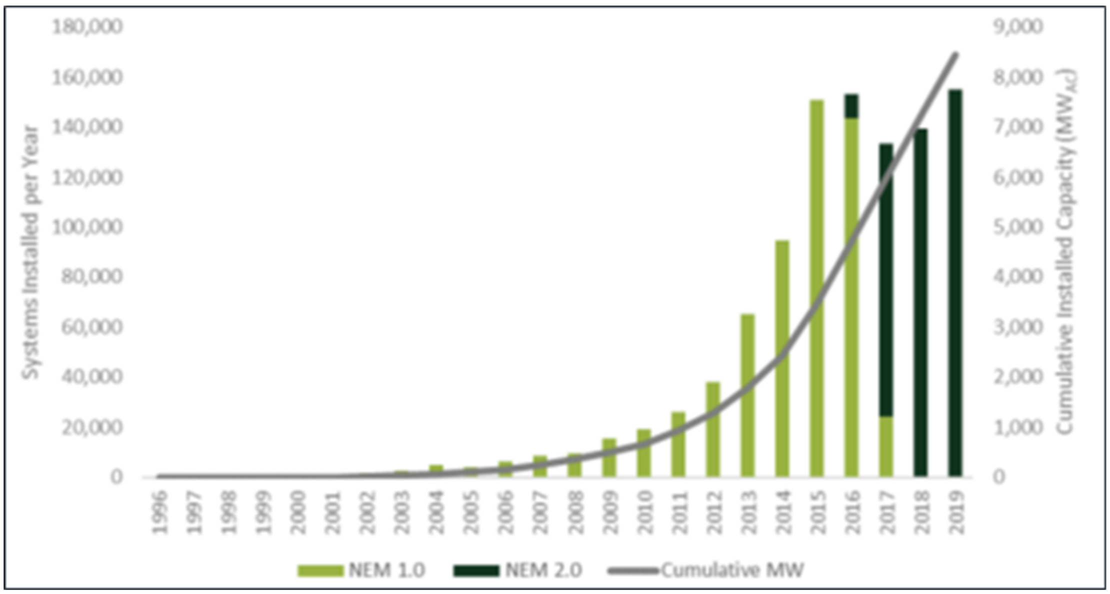
[7] *See* for example: https://www.pge.com/en_US/residential/solar-and-vehicles/options/option-overview/how-to-get-started/how-to-get-started.page?; https://www.pge.com/includes/docs/pdfs/myhome/saveenergymoney/solarenergy/CSI_Guide_To_Going_Solar.pdf; https://www.pge.com/en_US/residential/solar-and-vehicles/options/option-overview/how-to-get-started/find-a-contractor.page; https://marketplace.sce.com/solar/; https://www.sce.com/residential/generating-your-own-power/solar-power; https://www.sdge.com/residential/solar/getting-started-with-solar; https://www.sdge.com/sites/default/files/documents/step_by_step_guide_to_going_solar_2.an_.pdf?nid=19466; https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-Electricity_and_Natural_Gas/Solar%20Consumer%20Protection%20Guide%202021_English_v2.pdf.

[8] Energy Information Administration, 861 data on sales by each electricity supplier in California. https://www.eia.gov/electricity/data/state/.

SCE; and 1,495 MW by SDG&E.[9] Today, installed capacity of solar equipment on our customers' rooftops provides the equivalent of 25% of peak load for PG&E, 33% for SDG&E, and 16% for SCE.[10] In 2019, rooftop PV systems on our NEM customers' premises supplied an amount equivalent to 7% of California's electric supply.[11] Figure I-1 shows the installations associated with our NEM 1.0 and NEM 2.0 customers through 2019.

Figure I-1
NEM Systems Installed Per Year from NEM Tariff Vintage (through 2019)



NEM 2.0 Lookback Study, page 3.

Beyond rooftop solar, we have risen to the occasion to meet, and in fact have exceeded, the state's targets for development and production of renewable electric supply. We have already procured enough renewable resources to exceed our current obligations under California's renewables portfolio

[9] This reflects the Joint Utilities' interconnected capacity for residential and non-residential NEW customers for rooftop solar generation capacity as of May 2021.

[10] https://www.cpuc.ca.gov/NEM/. The Joint IOUs refer to peak generation (demand) here as defined by the 2019 FERC Form 1's maximum of Monthly Transmission System Peak Load for each respective IOU. The calculation is total installed behind the meter capacity divided by peak demand. This formula is the same formula used to determine progress toward the NEM 1.0 cap.

[11] Energy Information Administration, 861-M data on net metering and retail sales in California. https://www.eia.gov/electricity/data/eia861m/.

standard (RPS).[12] Our competitive procurements have helped to drive down the cost of renewables while also helping the state stay on track to deliver electric supply from solar, wind, geothermal, hydro, and other renewable resources. As reported in the CPUC's most recent annual report on retail suppliers' progress in satisfying RPS requirement, we had procured 52% of our customers' supply, relative to the RPS requirement of 33% by 2020. We are on track to meet the requirement to procure enough renewables to supply 60 percent of our customers' electricity demand by 2030.

We are proud of our part in California's journey to reduce air pollution, develop local renewable resources, create jobs, and eliminate the emissions that lead to climate change.

C. The net energy metering program has exceeded its goals

In the two-and-a-half decades since Senate Bill (SB) 656 launched California's NEM program in 1995, California has also met and exceeded the important goals of that act. SB 656's goals (shown in italics below) were bold in 1995, and California consumers, companies, and policy makers – including our companies – have stepped up to the challenge, with many positive outcomes for the state.

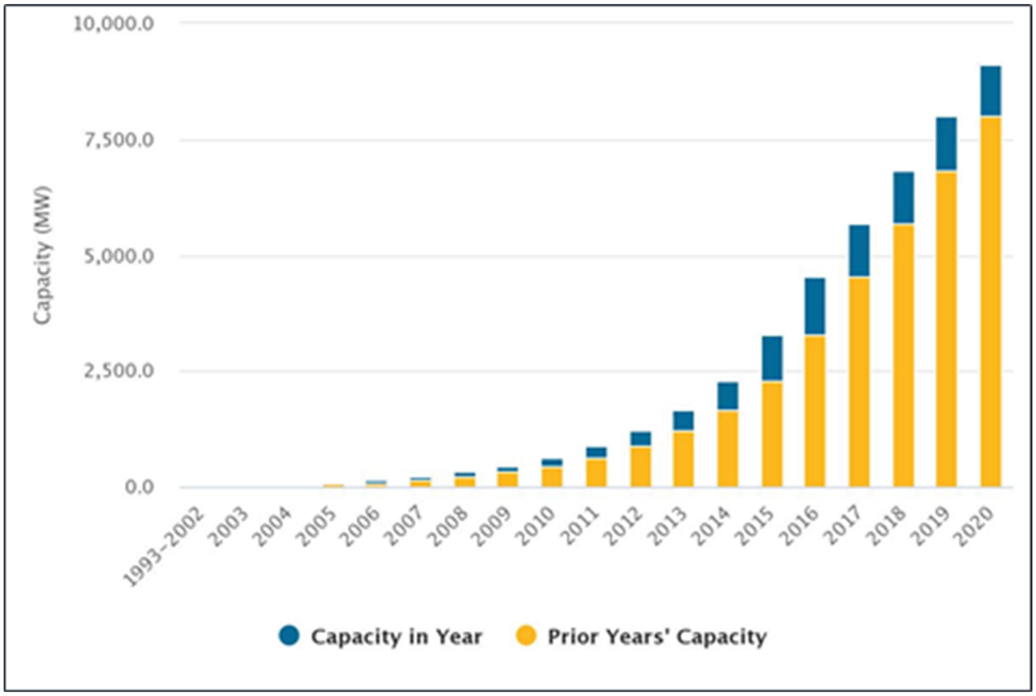
- *Encouraged private investment in renewable energy resources*: The Solar Energy Industries Association (SEIA) reports that the solar industry has invested nearly $72 billion in California (with $5.73 billion in 2020 alone).[13] Two thirds of NEM customers own their own solar systems, in addition to the investments of third-party owners of rooftop systems that sell power to consumers through power purchase agreements (PPAs) or leases. We have interconnected 9.4 GW of solar PV generation capacity as of the end of February 2021 (*See* Figure I-2), in addition to the 0.96 GW of capacity added in the service territories of the other California electric utilities.[14] Total rooftop PV deployment accounts for 10.36 GW of capacity across the entire state of California.

[12] California Public Utilities Commission, "2020 California Renewables Portfolio Standard: Annual Report," November 2020, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/2020%20RPS%20Annual%20Report.pdf.

[13] Solar Energy Industries Association (SEIA), Solar Industry Spotlight California, March 16, 2021, https://www.seia.org/sites/default/files/2021-05/California.pdf.

[14] https://www.californiadgstats.ca.gov/downloads/. Data are from the "Publicly Owned Utility (POU) & Other IOU Solar Data" datafile, which provides information about interconnection of NEM customers' solar PV systems, as reported to the U.S. Energy Information Administration.

Figure I-2
Capacity Installed on NEM Customers' Premises in Our Service Territories (through 2020)



Source: California Distributed Generation Stats, https://www.californiadgstats.ca.gov/charts/nem.

- *Stimulated state economic growth and jobs:* More than 2,000 solar companies operate in California, including 341 manufacturers, 951 installer/developers, and 714 other types of firms.[15] As of 2019, California ranked first among the states in terms of overall number of solar jobs (74,255 jobs), and 30% of all solar jobs in the nation were here in California.[16] Compared to other states, California had the third highest ratio of solar workers to the overall workforce (*i.e.*, 1 to 237), and the fourth highest number of solar jobs per capita.[17]

- *Enhanced the continued diversification of California's energy resource mix*: The state's overall energy mix shifted toward reliance on renewables in the electric sector: 38% in 1995

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[15] Solar Energy Industries Association (SEIA), Solar Industry Spotlight California, March 16, 2021, https://www.seia.org/sites/default/files/2021-05/California.pdf.

[16] Solar Energy Industries Association (SEIA), Solar Industry Spotlight California, March 16, 2021, https://www.seia.org/sites/default/files/2021-05/California.pdf.

[17] Solar Jobs Census, 2019: 249,983 solar jobs in the U.S. in 2019. https://www.thesolarfoundation.org/national/. Note that California's labor force (13.385 million) in 2019 represented 11% of the total U.S. labor force (163.537 million). U.S. Bureau of Labor Statistics, statistics for the U.S. https://www.bls.gov/eag/eag.us.htm and for California at https://www.bls.gov/regions/west/california.htm#eag.

> to 52% in 2018.[18] Even though the size of California's economy essentially doubled over this period,[19] its energy use grew by only 9% from 1995 through 2018, reflecting significant improvements in energy productivity since 1995.[20]

All in all, the NEM program, changing market trends and state and local policy drivers have combined to position California as a leader - perhaps the leader - in promoting customer adoption of renewable energy over the past two-plus decades.

D. <u>State and national polices also have driven California's success in meeting its climate goals</u>

While NEM has clearly supported the above outcomes, NEM has not done it alone: California's energy transition has benefitted from many other public policies aimed at deployment and use of clean energy. Some of these policies aim specifically at increasing California's reliance on renewable energy; others promote use of energy technologies with no greenhouse gas (GHG) emissions to help the state meet its climate goals. Some programs have been in place for many years, with most having been added since California launched its NEM program in 1996.

Figure I-3 shows how California has layered on many forms of incentives and requirements over recent decades so that the state's energy mix relies increasingly on renewable energy resources. In addition to the NEM program that has been in place for two-and-a-half decades, California and national policies have provided demand pull and market push to help adoption of renewables and cost reductions over time.

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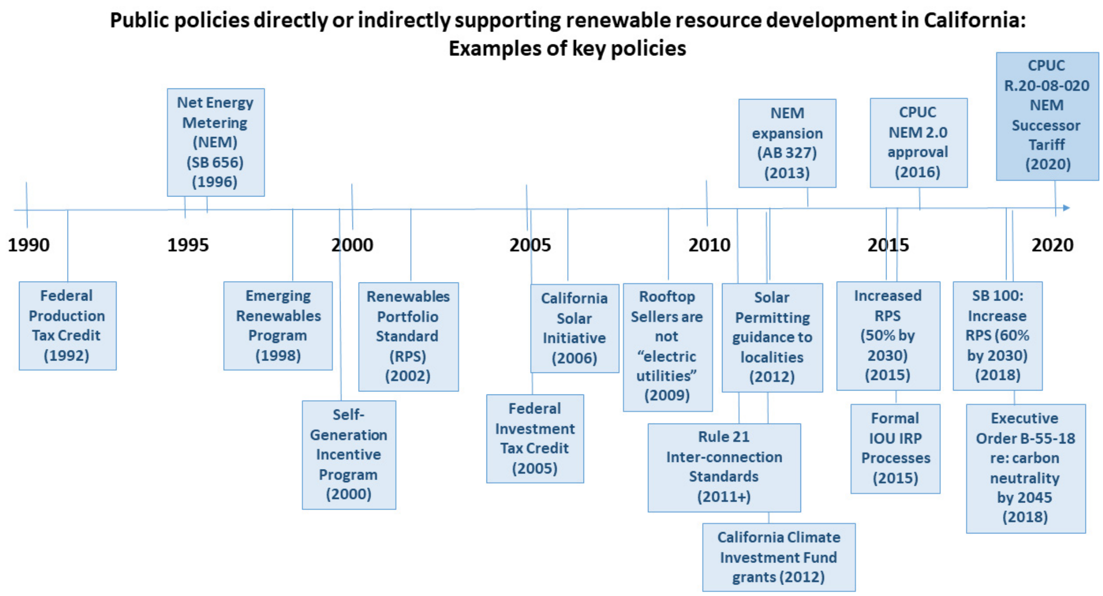
[18] EIA, Net Generation by State by Type of Producer by Energy Source, https://www.eia.gov/electricity/data/state/

[19] In 1997, California's gross domestic product (GDP) was $1,379.7 billion (in 2012$); using the same data series in 2012$, California's 2019 GDP was $2,800.5 billion. Federal Reserve Economic Data (FRED) on real total gross domestic product for California since 1997, at https://fred.stlouisfed.org/series/CARGSP.

[20] EIA, State Energy Data Report for 1995, Table 1, at https://www.eia.gov/state/seds/archive/seds1995.pdf; and EIA, State Energy Data System Report for 2018, Table 1 and Table C3.

Figure I-3
Public Policies Directly or Indirectly Supporting Renewable Resource Development in California: Examples of Key Policies



Source: Analysis Group

These many companion policies include the following, as illustrated in Figure I-3:

- 1992: Federal production tax credits (that created incentives for adoption of renewable technologies, with subsequent extensions).
- 1996: California's adoption of its first Net Energy Metering policy (SB 656).
- 1998: California's Emerging Renewables Program[21] which funded small grid-connected wind and fuel cell projects (but which is now closed).
- 2000: California's Self Generation Incentive Program (SGIP) which funded thousands of distributed energy projects over several decades[22] (with further updates in 2009).

[21] https://openei.org/wiki/Emerging_Renewables_Program_(California)#:~:text=The%20California%20Energy%20Commission%20offers,through%20its%20Emerging%20Renewables%20Program.&text=Small%20Wind%20Turbines%20(up%20to,10%20kW%20and%20%3C%2030%20kW.

[22] SB 970 (Duchney, 2000), SB 412 (Kehoe, 2009) https://www.cpuc.ca.gov/General.aspx?id=5935; https://www.cpuc.ca.gov/General.aspx?id=11430.

- 2002: California's Renewables Portfolio Standard (RPS), which required load-serving entities to rely on renewables for 20% of their supply to retail consumers by 2017.[23]
- 2005: Federal investment tax credits (ITC) that created incentives for investment, financing, and adoption of renewable technologies, with multiple extensions of the ITC after 2005.[24]
- 2006: California Solar Initiative and its various programs that provided incentives for the adoption of solar systems on single-family and multi-family buildings and in other settings, up to the end of the program in 2016.[25]
- 2009: Policy allowing non-utility third parties to install, own and operate a rooftop solar system and sell the output to customers for use on the same or adjoining property without becoming an electric utility subject to the Commission's jurisdiction.[26]
- 2011: Rule 21 interconnection standards that require standard terms and conditions for connecting distributed generation resources to local distribution systems (with multiple updates after 2011).[27]
- 2012: Periodically updated guidance for cities and towns to help improve the efficiency and costs of permitting of small solar energy systems and for building owners and solar equipment installers to help them navigate the permitting process.[28]
- 2012: Grants from the California Climate Investment fund, which include, among many other things, support for communities to deploy solar projects.[29]

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23 https://www.cpuc.ca.gov/rps/.

24 https://www.seia.org/sites/default/files/resources/History%20of%20ITC%20Slides.pdf; https://fas.org/sgp/crs/misc/R43453.pdf.

25 https://www.greentechmedia.com/articles/read/the-legacy-of-the-california-solar-initiative#:~:text=The%20California%20Solar%20Initiative%20(CSI,million%20roofs%20around%20the%20state.

26 https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=218.

27 https://www.cpuc.ca.gov/Rule21/.

28 California Office of Planning and Research, "Solar Permitting Guidebook," 4th Edition, 2019, https://opr.ca.gov/docs/20190226-Solar_Permitting_Guidebook_4th_Edition.pdf.

29 https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auctionproceeds/2021_cci_annual_report.pdf.

- 2013: Enactment of AB 327 to expand the availability of California's NEM program and the preparation of distributed resources plans by investor-owned utilities (IOUs).[30]
- 2015: IOUs' integrated resource planning and distributed generation planning, which require utilities to rely on lowest-cost resources (including distributed energy resources) to meet capacity and generation portfolio needs as well as to meet distribution system reliability goals.
- 2015: Increase in the RPS to require electricity sellers to rely on renewables for 50% of supply to retail customers by 2030.[31]
- 2018: SB 100 (2018, de Leon) to require electricity sellers to rely on renewables for 60% of supply to retail customers.[32]
- 2018: Executive Order B-55-18, which put California on a path to net zero emissions by 2045.[33]

Together, these programs reinforce the state's commitment to and support for sustainable growth in renewable energy, economic development, consumer choices, and clean energy outcomes.

Going forward, the Title 24 Building Energy Efficiency Standards will further drive deployment of solar systems on California rooftops by requiring that all new homes in California include solar PV installations in conjunction with measures to increase the efficiency of energy use in these residential buildings.[34] The combined effect of these policies and market conditions creates a positive outlook for solar expansion in the state, as indicated below (Figure I-4) in a California Energy Commission projection from 2020.

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30 https://www.cpuc.ca.gov/NEM/.

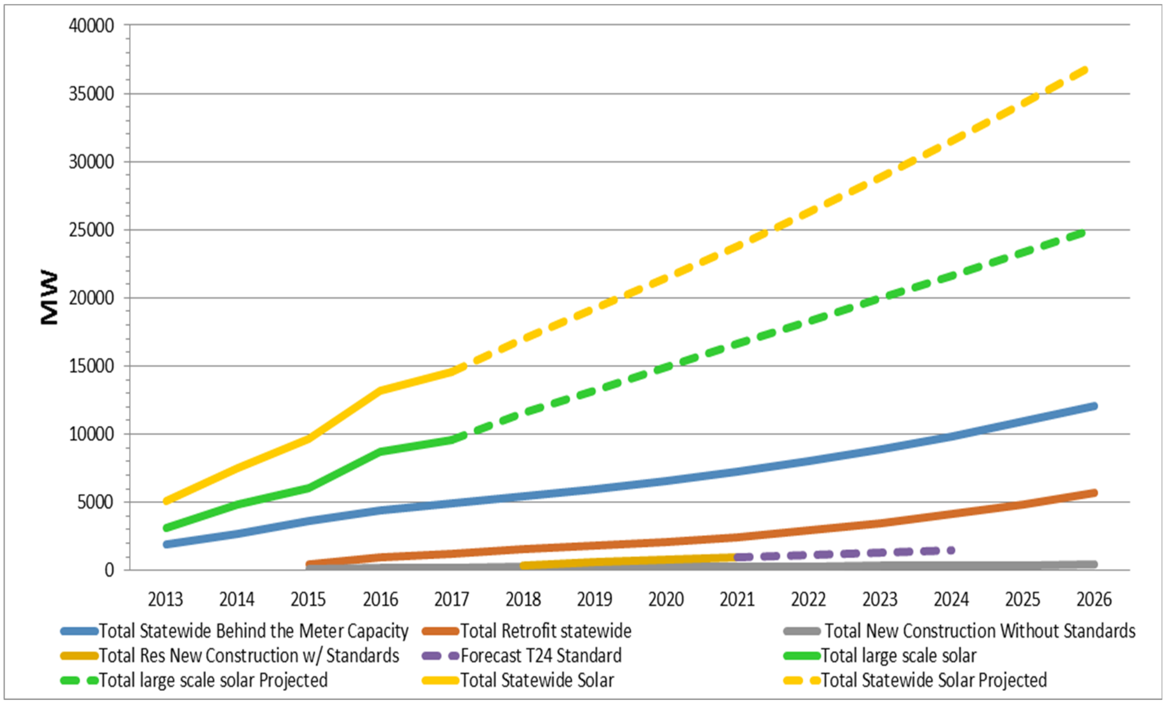
31 https://www.cpuc.ca.gov/rps/#:~:text=California's%20RPS%20program%20was%20established,a%2050%25%20RPS%20by%202030.

32 https://www.cpuc.ca.gov/rps.

33 https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

34 https://ww2.energy.ca.gov/2018publications/CEC-400-2018-020/CEC-400-2018-020-CMF.pdf.

Figure I-4
Projections of Growth in Solar Market in California: Total, Title 24, Behind the Meter PV, and Large-Scale Solar



Source: California Energy Commission, "Frequently Asked Questions 2019 Building Energy Efficiency Standards," Response to Question 6. https://www.energy.ca.gov/sites/default/files/2020-06/Title24_2019_Standards_detailed_faq_ada.pdf.

E. <u>Problems in the current NEM program</u>

Along with these many successes, there are significant downsides associated with maintaining the current NEM program. The need for reform is well recognized. Indeed, the required NEM reforms specified in AB 327 (AB 327 (Perea, Stats. 2013, ch. 611) are intended to address these downsides and to allow the state to manage continued growth in rooftop solar responsibly and sustainably, especially among underserved customers who historically have had less access to solar.

The highly negative downsides of the current NEM program include the following:

- **The program is not cost-effective:** The current NEM tariffs (NEM 2.0) are not cost-effective from a total resource-cost point of view or from the point of view of non-participating customers. The tariffs only provide net benefits for those customers that install rooftop solar (or solar PV + storage) via those tariffs.[35] NEM customers with rooftop PV enjoy extremely short payback periods (e.g., five years or less) and receive the bill-saving benefits of subsidies from other customers for more than a decade beyond their payback period. The first-year bill savings for NEM customers in San Diego Gas & Electric's service area are $4,100 with $3,600 of the bill savings comprising subsidy from non-participating customers to NEM customers. NEM customers receive the bill-saving benefits of subsidies from other customers for more than a decade beyond their payback period.

- **The cost shift is already massive and getting worse:** The cost shift from NEM participants to non-participants is already enormous and growing. The existing NEM program already results in a $3.4 billion cost shift,[36] which will grow in the future if not addressed in the NEM successor tariff being considered in this proceeding. Because NEM 1.0 and 2.0 customers have 20-year legacy treatment periods, $3.4 billion is a baseline amount that will be shifted to nonparticipating customers *every year* until customers' legacy periods end. This results in an average bill increase of ~ $245 each year for Non-CARE customers without solar in SDG&E's service area, which is the utility with the largest penetration of solar.[37] This is neither fair nor sustainable. (Chapter 3 of our testimony explains our cost analysis.)

- **Lower-income customers are disproportionately harmed:** The cost shift is particularly unjust and unreasonable because it is inequitable. Participants in the NEM program, on average, have higher incomes.[38] This means that low- and middle-income customers disproportionately bear the cost shift. This is an income transfer from our poorer customers to wealthier ones. The burden of high energy costs is already largest among low-income customers who spend a relatively high proportion of their income on energy bills. (See Chapter 2.) The current NEM program exacerbates that problem.

- **The current NEM 2.0 rate design favors higher-income customers:** The current NEM program has more attractive incentives for customers not on income-discounted rates, thus creating another source of inequity. Because the NEM program is tied to retail rates, the program provides better value for higher-income customers than those income-qualified customers on discounted rate plans (e.g., California Alternate Rates for Energy (CARE) program). In light of the extraordinary reduction in the costs of solar (see Figure I-5), these incentives are simply much too generous and incentives should be targeted to where they are most needed.

- **The program presents an economic challenge to California's climate goals:** The current program raises the cost of electricity for all our customers, creating a disincentive for electricity use and thus making it harder to achieve climate goals through electrification of

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[35] NEM 2.0 Lookback Study, page 5 (Table 1-2). Chapter 3 of this testimony describes our cost-effectiveness evaluation in more detail.

[36] As of June 1, 2021. *See* Chapter 3.

[37] For PG&E, today the annual average bill increase for Non-CARE non-participants is $170. For SCE, the annual Non-CARE average bill increase for non-participants is $115.

[38] Verdant Associates, "Net-Energy Metering 2.0 Lookback Study," Submitted to the California Public Utilities Commission Energy Division, January 21, 2021, pages 32-33.

buildings and vehicles, which are key to the State's strategy to reduce GHG emissions. Higher electricity costs also make adoption of technologies like electric heat pumps less cost-effective and less attractive to customers.

- **The current program does not promote storage:** The existing NEM program fails to provide sufficient price signals to promote more modern technologies and uses. Under most of our rate plans, there is insufficient differentiation between onsite use and exports, and insufficient price differentials for exported energy during the least- and most-valuable hours of the day. This means the current program does not do enough to promote adoption of paired energy storage, which is important—if not essential –to achieving the State's climate goals. Compared to 2015-2016, curtailment of solar and wind resources in the CAISO has increased by over 400 percent, from 242 GWh/yr to 1,235 GWh/yr for 2019-2020.[39] As noted by CAISO, "Curtailing renewables is counterintuitive to California's environmental and economic goals. It reduces the output from the renewable plants in which the state has invested and could result in overbuilding renewable plants to ensure that the state meets its 50-percent renewable mandate. Overbuilding the electric system is not financially sound."[40] Further, over-reliance on solar resources can create reliability challenges as outlined in the joint CPUC, CAISO, and CEC analysis of the August 2020 extreme heat wave event: specifically, "With today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. This is because air conditioning and other load previously being served by solar comes back on the bulk electric system. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability, and this challenge is amplified during an extreme heat wave."[41] Storage, dispatchability, and time-of-use rates can mitigate these cost and reliability impacts, and the NEM successor tariff should address these issues.

- **The current program is not durable**. NEM customers today pay certain non-bypassable charges[42] based on consumption from the grid. However, because these non-bypassable charges are assessed only on energy procured from the utility, NEM customers pay less in non-bypassable charges than comparable non-NEM customers, contributing less to state policy programs like income-qualified and energy efficiency programs. As customers begin to adopt solar-paired storage, they will be able to bypass even more of these "non-bypassable" payments, making this problem worse.

- **The current program discourages innovation**. NEM compensation far exceeds the payments a customer could receive by participating in the California Independent System Operator (CAISO) wholesale market through a demand response program or through

[39] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[40] http://www.caiso.com/Documents/CurtailmentFastFacts.pdf.

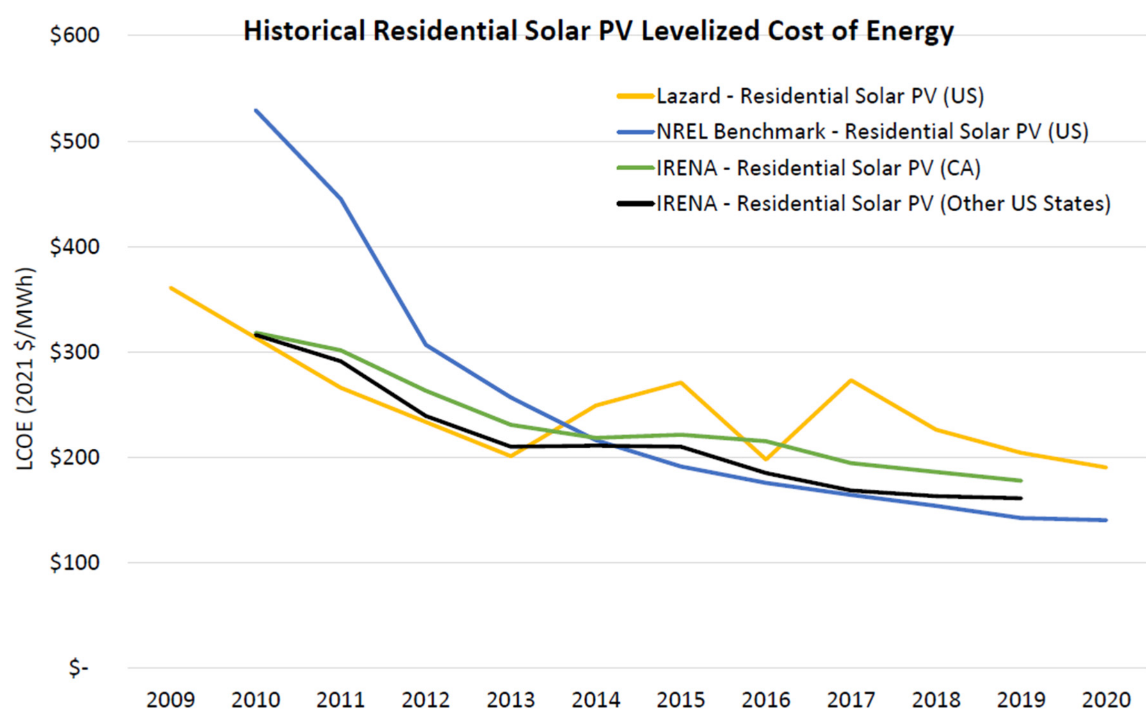
[41] http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf, p. 4.

[42] Non-bypassable charges include public purpose program charges, nuclear decommissioning charges, competition transition charges, and the Wildfire Fund – Non-Bypassable Charge, which recently replaced the Department of Water Resources Bond Charge.

participation in a potential new power-sharing tariff or microgrid. The excess compensation discourages innovation in these other measures, as well as in energy storage and dispatch.

In short, the NEM 2.0 tariffs are unsustainable and neither just nor reasonable. There are, however, relatively simple solutions to these problems that will continue to encourage healthy growth of solar.

Figure I-5
Historical Residential Solar PV Levelized Cost of Energy



Sources:
[1] Lazard Levelized Cost of Energy Analysis — Versions 6.0-14.0.
[2] NREL Benchmark, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, https://www.nrel.gov/docs/fy21osti/77324.pdf.
[3] NREL Annual Technology Baseline Data, https://atb.nrel.gov/electricity/2020/data.php.
[4] IRENA (2020), Renewable Power Generation Costs in 2019, https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019.

F. <u>Overview of Our Reform Tariff Proposal</u>

The Joint Utilities propose a Reform Tariff for new NEM customers with certain elements as a package. The essential elements of the proposed Reform Tariff are as follows:

1. A more cost-based residential default rate for residential customers on the reform tariff. It will include time-of-use rates for three periods: on-peak, off-peak and super off-peak for the summer and winter seasons.

2. A net billing structure, in which all energy delivered to the customer is billed at the retail rate, and all energy exported to the grid is compensated at the export compensation rate. A value-based export compensation rate (ECR) decoupled from the retail rate, with the export rate set at the avoided cost based on a one-year forward estimate in different time periods when the customer injects supply into the grid and with the rate updated annually.

3. A grid benefits charge (GBC) for residential customers and non-residential customers based on solar system size and updated annually, with the GBC designed to recover distribution, transmission and non-bypassable charges less relevant avoided costs.

4. The netting of a customer's consumption and exports on an instantaneous basis during hourly time-of-use (TOU) periods, with monthly true-ups.

Additional important elements of the proposal include:

- No change in existing NEM 1.0 and NEM 2.0 customers' terms and conditions of service.

- A financially equivalent dual-meter rate option called the Value of Delivered Energy ("VODE") tariff that provides better information on generator output that may be useful for more advanced system uses (e.g., microgrids, power-sharing)

- An Income-Qualified Discount (IQD) to reduce the GBC for income-qualified and other qualifying customers that adopt solar, in conjunction with export compensation at the full (non-discounted) avoided cost available to other DG-ST customers.

- A pilot program called "Savings Through Ongoing Renewable Energy ("STORE") for income-qualified customers to install behind-the-meter storage which can be subject to the utility's dispatch control.

- Two proposed revised virtual net metering successor tariffs -- one applicable to income-qualified housing and one for customers in other buildings with a VNEM arrangement. These customers do not take service under the Reform Tariff, exports from the building are compensated at the avoided cost approach used in the proposed Reform Tariff and receive a dollar credit associated with these exports.

This package of rate design and program elements are designed to work together to reduce the cost shift from participating to non-participating customers, support a value proposition for new solar customers (in particular for income-qualified customers) and encourage solar-paired storage adoption. To that end, the proposal:

- **Is based on our cost to serve. This is a basic tenet of utility ratemaking, and it is the foundation of an appropriate NEM successor tariff.** We want to support our customers' choices regarding whether they want to adopt rooftop solar and giving them better information is supportive of customers' choices. Designing the Reform Tariff around having all customers pay their fair share of what it costs to serve them better aligns everyone's interests and needs.

- **Pays customers for the power they supply to the grid at the same rates we pay other suppliers. We propose use of our avoided costs as the basis for compensating exports to the grid.** This is fair, cost-justified and value-based compensation; compensating exports according to their actual value to the system is common among jurisdictions which have reformed net metering as well as for several California municipal utilities and two small multi-jurisdictional utilities subject to CPUC regulation.

- **Collects from customers their fair share of the cost of using the grid**. Our grid-benefits charge is designed to recover the costs we incur to serve them when they do not have sufficient on-site supply to cover their own electricity use. They use the grid like other customers at such times and should pay for their service. Our proposal is fair to these customers and other customers not adding solar on their roofs.

- **Encourages customers to install storage along with rooftop solar.** Customers adding storage will better manage their electric use and utility bills and will align the timing of their purchases from and sales to the grid to maximize their benefits and the value of their supply to the grid. Our proposal requires these new solar customers to take service on an instantaneous time-of-use (TOU) basis, with monthly true-ups, in which their power exports to the grid may only be netted within their respective time-of-export period. TOU netting will provide a more accurate price signal for customers, further encouraging load shifting, and ensure that customers exporting during the middle of the day are not able to use these credits to offset increased consumption during the evening peak period.

- **Encourages adoption of rooftop solar and storage by income-qualified customers**. We recognize that participation in rooftop solar programs of lower-income customers has lagged, as compared to non-income-qualified customers. Our proposal is designed to close that gap. For example, there is no reason why a kWh exported from a CARE customer should be valued any differently than a non-CARE customer, but because NEM is tied to retail rates, the CARE customer's kWh is currently compensated at a lower value. We are proposing the same export compensation for all customers to remedy this regressive feature of the NEM program. This export compensation, in addition to other incentives, will lead to a more equitable customer solar adoption through the NEM Reform Tariff.

Our proposal is a package, with all the pieces designed to work together. Each component is essential to ensure that a NEM successor tariff is equitable for all customers while also sustaining growth in customer-sited generation and improved value propositions for residential customers in disadvantaged communities.

Adoption of solar and solar-paired storage will continue under our proposal without the inflated financial incentives under the current NEM program. The reductions in installed costs of PV systems in the decades since NEM was adopted in California and the expectation that electricity rates will increase over time will continue to drive solar adoption. Customers wanting to lock in a hedge against future rate increases, while adding an on-site source of back-up power for their homes, will be motivated to add solar and storage systems. Our proposal also improves the value proposition for income-qualified customers to adopt solar-paired storage options relative to today.

G. **Conclusion: We should honor the 25 years of success of the NEM experience and move forward with bold reforms that will benefit our customers**

The NEM program began 25 years ago. It played an integral role in helping to kick-start California's rooftop solar market. NEM spurred deployment of more solar PV capacity here than anywhere else in the country. In fact, California's program helped to launch an industry from fledgling start up to a mature industry with sales and growth opportunities here and in countless other markets around the country. Given California's size and early-mover role, one might even view California's 25 years of NEM success as having propelled the nation's solar movement.

But the kick-start needed 25 years ago is no longer needed. As shown in Figure I-3, California now has a robust set of policies aimed at deploying renewables, including solar PV on residential buildings. AB 327 (Perea, Stats. 2013, ch. 611) and NEM 2.0 added gradual steps toward that change. Now significant and smart reforms are needed because NEM 2.0 is simply not sustainable. We propose a significant change to the existing NEM tariff because we need it to help all our customers, not just a few. It accomplishes that by doing the following:

- Addressing the cost shift from participants to non-participants by requiring new customers on the Reform Tariff to pay their fair share of infrastructure and public purpose program costs;
- Providing fair compensation to Reform Tariff customers for the value that their supply provides to the electric system;
- Improving the value proposition for income-qualified electricity consumers to adopt solar relative to non-income-qualified customers and creating a program to facilitate income-qualified early adoption of storage;

- Allowing customer-sited renewable generation to continue "to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities";[43] and
- Supporting electric system reliability by providing an incentive for pairing solar with storage and making BTM storage functionalities available to curtail or ramp in response to electric system needs.

The chapters that follow explain how our proposal accomplishes these goals. We encourage the Commission to accept our proposed Reform Tariff.

[43] Public Utilities Code Section 2827.1. Notably, the E3 Successor Tariff Options Report (page 8) reaches similar conclusions: "Meeting the directives of AB 327 requires a rate mechanism that precludes the shifting of non-avoidable, fixed costs of serving customer-generators to nonparticipating customers. The choice of a rate framework that ensures best practice must treat customer-generators comparably to nonparticipating customers, while at the same time maintaining a viable value proposition to customers investing in onsite renewable generation, as measured by providing a reasonable payback period."

II.

NEM TARIFF REFORM AND MARKET TRENDS IN THE U.S. AND LESSONS LEARNED FOR SOUND POLICY DESIGN

A. Executive Summary and Overview: NEM has been a valuable tool for launching the market for rooftop solar but now that the market has matured, reforms are now warranted

Starting decades ago, many states put in place an important policy innovation — net energy metering (NEM) — to allow and then to promote the adoption of customer-sited electricity generation. Eventually, forty states, the District of Columbia and many U.S. territories instituted a NEM tariff. These tariffs typically pay the customer for excess energy the customer does not use and exports to the grid. Often, the compensation was based on the customer's full retail rate, which is inherently more than the value of any energy exported. This means that the NEM customer does not pay the full cost of using the grid, and thus the costs avoided must be paid by other retail customers, that is, there is a "cost shift."[44]

Cost shifts associated with NEM programs designed to spur adoption for a nascent market are typically relatively small when penetration rates for NEM-supported rooftop solar installations are relatively low.

California was not the first to adopt NEM, but since enacting NEM in 1996, California has surpassed every other state in the deployment of rooftop solar by customers on NEM tariffs. NEM has helped California to move rooftop solar from a novelty to a norm. As explained further below, California's NEM program has more installed distributed generation capacity than any other state: Over 10 GW of rooftop PV as of the start of 2021 (as described in Chapter 1). Ninety percent of that capacity has been interconnected to the distribution systems of the Joint Utilities. California also has the highest

[44] Under public utility regulation principles in most states, including California, the local utility is granted the exclusive right to provide delivery service to retail electricity customers in a given area in return for undertaking the obligation to plan for and serve existing and anticipated electric demand in that area. The utility is entitled to compensation for its reasonable expenses and investment to provide such service, plus a reasonable return on the investment. Under this regulated public utility model, regulators establish a revenue requirement for the utility's operations, and rates are designed to recover such revenue requirements. In such a ratemaking framework, any costs not compensated in rates by one subset of customers will need to be recovered from and paid by other customers.

percentage of residential rooftop PV installation of any state, except for Hawaii. Finally, one in every three solar-industry jobs in the U.S. exists in California.

And yet, California has not significantly changed the structure of its NEM compensation arrangements in 25 years.

In the past half-decade, other states experiencing relatively high penetration rates for NEM-supported rooftop solar have received regulators' approval for reforms to their NEM tariffs to address increasing cost shifts borne by non-participating customers. These reforms were controversial in Arizona, Hawaii, and Nevada, for example, in part related to the potential effect of NEM tariff reforms on existing NEM customers and additional adoption of rooftop solar by other customers. Despite these controversies, residential customers continued to adopt solar equipment even after the successor tariffs went into effect and even the tariff modifications led to longer payback periods.

Several trends have enabled continued growth in solar adoption:

- continued declines in the installed costs of PV systems;
- continued declines in the cost of residential storage systems, providing an attractive combination when paired with solar, especially where NEM tariff reforms provide price signals for the timing of injections of power into the local grid;
- customers' interest in managing their electricity bills and installing back-up electricity supply at their own home; and
- the maturation of the solar industry over the past decades.

These and other trends account for a positive outlook for the ability of the industry to deliver attractive value propositions to customers after tariff reforms.

Policy transitions are often part of good policy design. This is especially true where a new policy relies on subsidies and on relatively simple policy structures to kick-start markets and where the original approach is no longer appropriate as the market develops and matures. California has had success in the past in modifying incentives for deployment of various clean-energy outcomes as their markets have evolved (for example in the California Solar Initiative, in the Clean Vehicle Rebate Project, and in procurements of power under the Public Utilities Regulatory Policies Act (PURPA)) with continued positive outcomes for clean energy after such policy reforms. The Commission should similarly transition the current NEM program consistent with sound policy design principles.

Building on the description of California's NEM program to date in Chapter 1, Chapter 2 puts California's achievements and upcoming NEM-reform challenges in a national context. This Chapter covers trends in other states' NEM programs, trends in the costs of rooftop solar and distributed storage, and the outlook for markets for solar and storage on customers' premises. Finally, this Chapter makes recommendations for elements of sound policy design that the Commission should consider as it reviews proposals for a successor tariff to NEM 2.0.

The purpose in providing this context is to give the Commission information that is relevant and helpful to determining which NEM reform proposals (i) address the critically important cost shifts that have resulted from the current NEM tariffs while (ii) also ensuring that customer-sited renewable generation can continue "to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."[45]

B. The national context for NEM policies and behind-the-meter generation

1. Many states have used NEM to encourage early adoption of rooftop solar by retail customers

NEM tariffs are so common across the country that they became the norm for starting up rooftop solar deployment in the U.S. NEM has been broadly viewed as a key tool to encourage the end-use consumers' adoption of on-site generation. And at initial and relatively low levels of penetration of NEM service in utilities' service territories, it has been said that "the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future."[46] While that was true in California 25 years ago when NEM was first adopted, it no longer is so.

As shown in Figure II-6, most states currently have mandatory net metering rules or have had such rules in the past and several states are either transitioning away from NEM or have already

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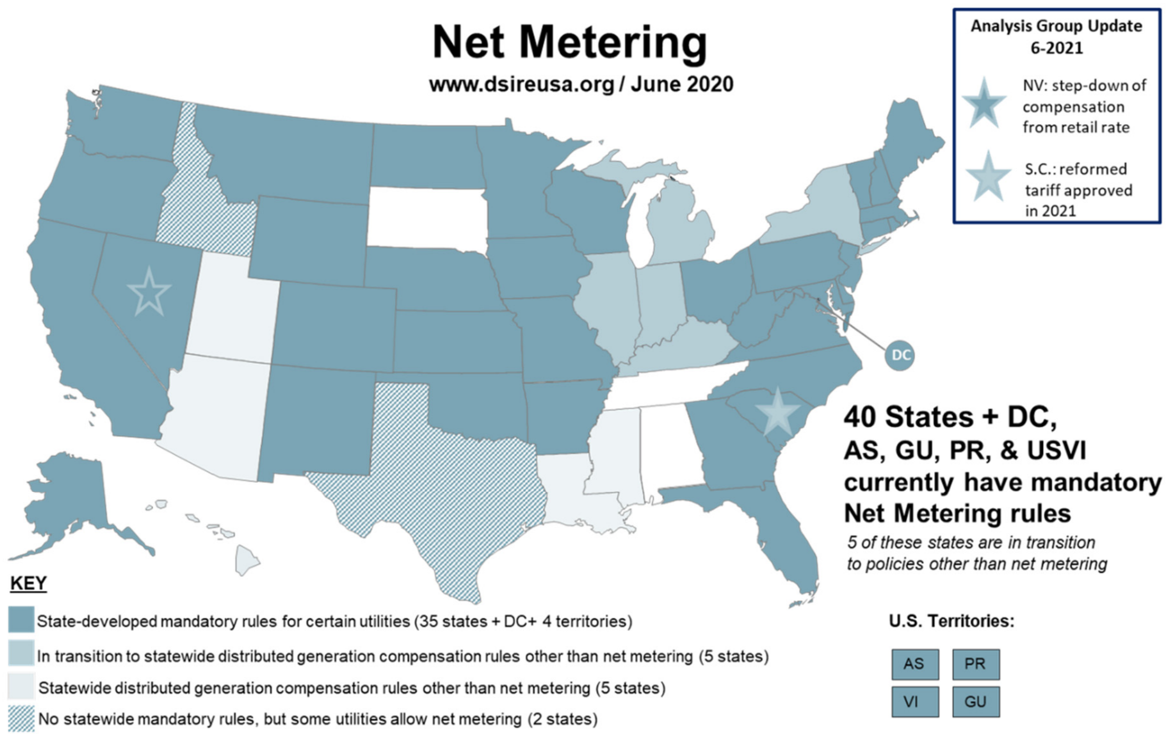
45 Assembly Bill (AB) 327 (Perea, Stats. 2013, ch. 611), codified in Pub. Util. Code § 2827.1(b)(3).

46 Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, January 2017, page 29, https://www.osti.gov/servlets/purl/1469160.

done so. In this latter category are states like Arizona, Hawaii, Nevada, and South Carolina (as discussed later in this chapter.

Figure II-6
Net Metering in US as of June 2020 (with June 2021 Update)



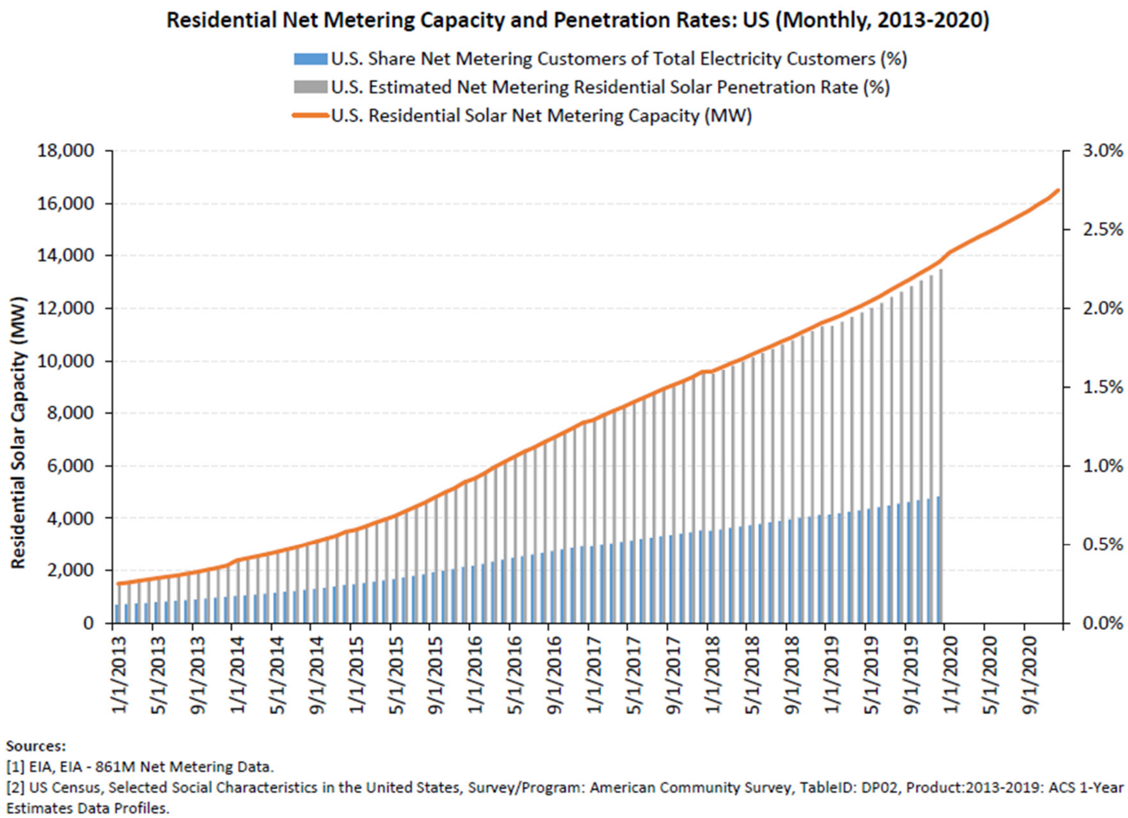
https://www.dsireusa.org/resources/detailed-summary-maps/

NEM has been broadly viewed as a key regulatory strategy to drive the adoption of rooftop solar PV systems in the U.S.[47] Across the many states with NEM tariffs valuing residential customers' exports to the grid at the full retail rate, the U.S. has seen 16.5 GW of solar PV systems adopted by residential NEM customers, an eight-fold increase since 2013 (as shown in Figure II-7). Based on recent data shown in Figure II-7, residential customers on NEM service account for 0.8% of all electricity customers in the U.S. and approximately 2.2% of U.S. households have adopted solar on NEM rates. Early debates about the cost shifts and electricity price impacts on non-NEM customers were met with research and analysis that indicated that early phases of adoption with relatively low

[47] ICF, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar," prepared for the U.S. Department of Energy, May 2018, https://www.energy.gov/sites/prod/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf.

levels of penetration of NEM service were not producing material impacts on retail electricity prices.[48] But this is no longer the case in California.

Figure II-7
Residential Net Metering Capacity and Presentation Rates:
US (Monthly, 2013-2020)



2. NEM has helped to convert rooftop solar from a novelty to a norm, with California in the lead

In places where more and more customers have installed rooftop solar under NEM tariffs tied to full retail rates, the cost-shift impacts have grown. This is true for California.

California's rooftop solar deployment among NEM customers accounts for a substantial portion of the national outcomes. As shown in Figure II-8, residential NEM customers in California have installed 6.7 GW of rooftop solar capacity; this equates to 41% of the national total.

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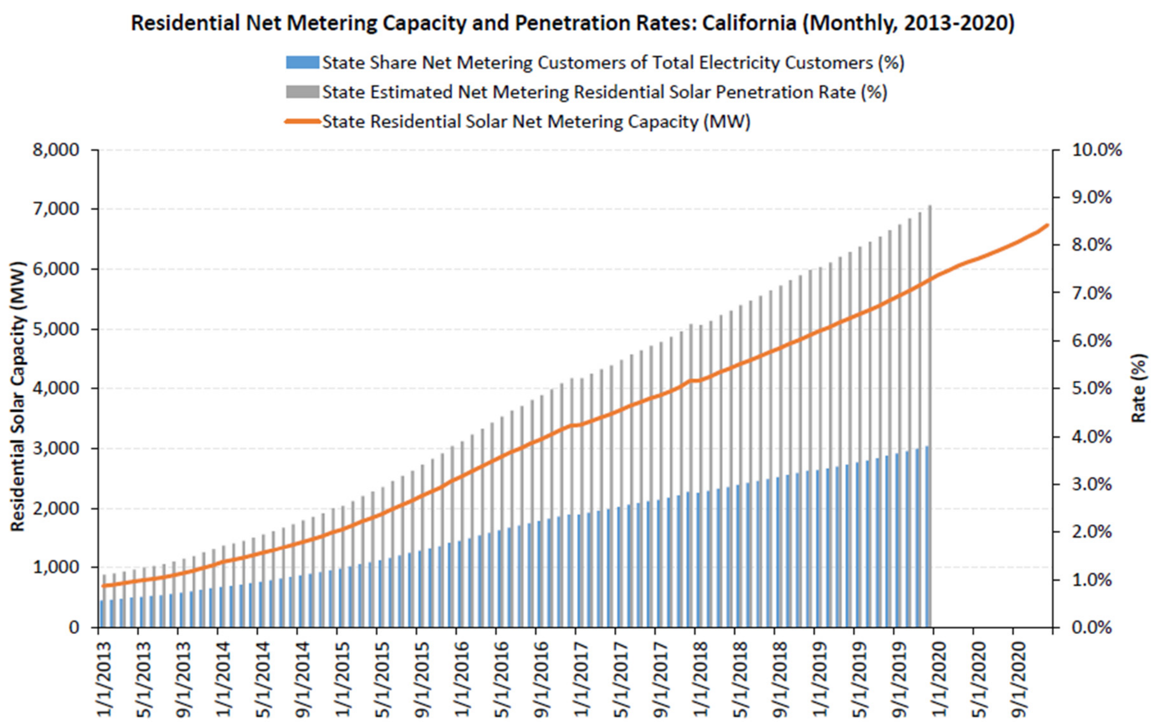
[48] Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," Lawrence Berkeley National Laboratory, January 2017, page 29, https://www.osti.gov/servlets/purl/1469160.

These households on NEM rates account for 9% of all households in the state, and the participation rates for residential customers on NEM in the service areas of PG&E, SCE and SDG&E as detailed below.

Figure II-8
Residential Net Metering Capacity and Penetration Rates: California (Monthly, 2013-2020)



Sources:
[1] EIA, EIA - 861M Net Metering Data.
[2] US Census, Selected Social Characteristics in the United States, Survey/Program: American Community Survey, TableID: DP02, Product:2013-2019: ACS 1-Year Estimates Data Profiles.

Compared to other selected electric utilities in other states that have reformed their NEM tariffs (*i.e.*, in Arizona, Hawaii, Nevada, New York, and most recently in South Carolina), California's deployment of rooftop solar is quite robust, with relatively high shares of system peak demand and residential customer participation. In its February 2021 study, "Review of Net Metering Reforms Across Select U.S. Jurisdiction"[49] prepared by the North Carolina Clean Energy Technology Center (NCCETC) at the request of the Joint Utilities, the NCCETC reported on MW of installed solar PV

[49] This will be referred to as "NCCETC Study" in this testimony. It was submitted as Appendix 1 to Attachment A of the 3-15-2021 Joint Proposal of PG&E, SDG&E and SCE in Docket R.20-08-020.

capacity on residential NEM customers' premises for several electric utilities that either had moved away from NEM tariffs or modified elements of them. (The NCCETC Study is attached as Appendix B to this testimony.)

Figure II-9 shows the cumulative capacity adopted in recent years by California's three major investor-owned utilities (PG&E, SCE, SDG&E) and six of other utilities, some of which have reformed their NEM tariffs (Arizona Public Service (APS); Duke Energy Carolinas (Duke SC); Hawaii Electric (HECO); Nevada Power (NV Energy); Niagara Mohawk Power (now known as National Grid NY)) and one of which (Sacramento Municipal Utility District (SMUD)) previously attempted to reform its tariff and is still in discussion about how to do so.[50] These utilities originally offered NEM service that compensated exports to the grid at the full retail rates. Several of the Western utilities (including those in Arizona, Hawaii and Nevada) showed substantial cumulative capacity additions (especially relative to their population sizes) during the past decade.[51] But the Joint Utilities have added substantially more overall capacity.

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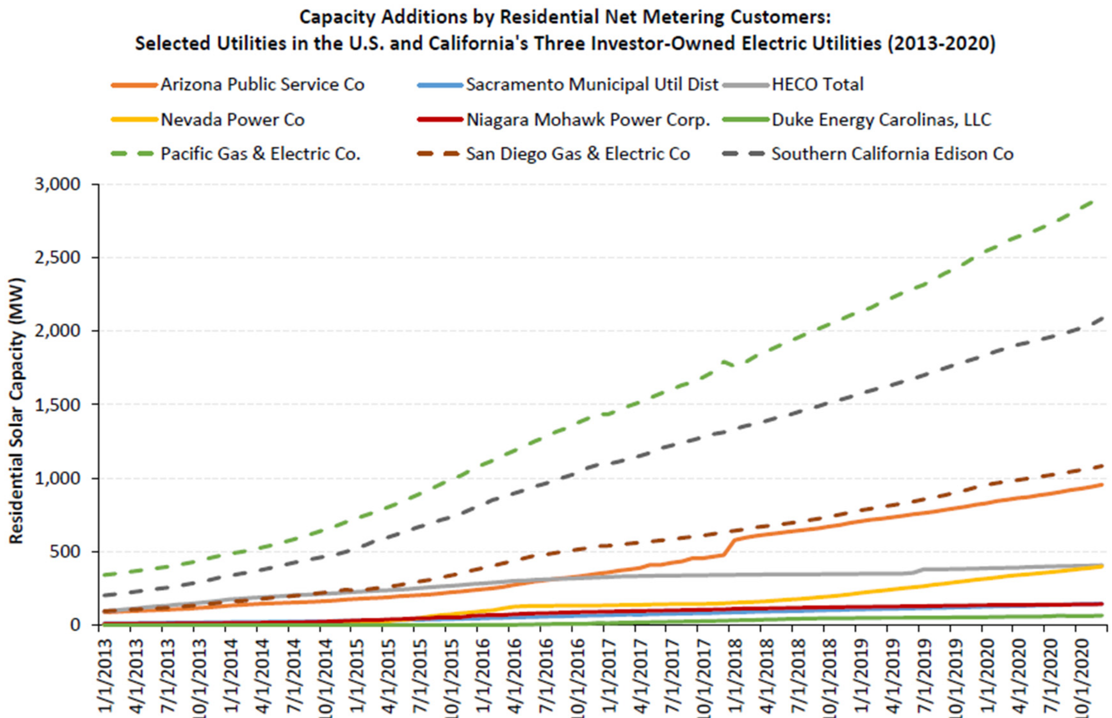
50 NCCETC Study, Figure 1. See also: SMUD's 2030 Zero Carbon Plan (approved April 28, 2021), pages 45 and 105, at https://www.smud.org/-/media/Documents/Corporate/Environmental-Leadership/ZeroCarbon/2030-Zero-Carbon-Plan-Technical-Report.ashx.

51 Arizona is the 14th largest state (with an estimated 7.5 million people as of 2021); Nevada is the 32nd largest state (with 3.2 million); and Hawaii is the 41st largest state (with 1.4 million). California has the largest population, at 39.6 million people. https://worldpopulationreview.com/states.

Figure II-9
Capacity Additions by Residential Net Metering Customers:
Selected Utilities in the U.S. and California's Three Investor-Owned Electric Utilities (2013-2020)



Sources:
[1] EIA, EIA - 861M Net Metering Data.
[2] North Carolina Clean Energy Technology Center at North Carolina State University, A Review of Net Metering Reforms Across Select U.S. Jurisdictions, January 2021, p. 5.

The penetration rates for PG&E, SCE and SDG&E residential NEM customers are also high compared to the other utilities highlighted in the NCCETC study. As shown in Table II-1, the Joint Utilities' residential NEM customers have installed large quantities of solar capacity, which represents a relatively high percentage of peak demand. The Joint Utilities' participation rates are among the highest in this group of utilities.

Table II-1
Installed NEM Capacity and Participation Rates

Utility	Installed Total NEM PV - (MW)	Installed Residential NEM PV (MW)	Total NEM as % of Peak Demand	NEM PV Participation as % of Residential
PG&E	4,681	2,852	25%	10.6%
SCE	3,044	2,050	16.1%	8.4%
SDG&E	1,381	1,067	33.1%	15.4%
APS	1,242	941	17.5%	10.2%
HECO	518	406	32.7%	16.0%
NV Energy	491	413	6.6%	5.3%
National Grid NY	419	142	7.2%	1.5%
LADWP	387	271	6.9%	3.7%
SMUD	242	144	8.3%	5.8%
Duke SC	108	76	n/a	1.4%

Notes:
MW of capacity: as of end of year, 2020, for the Joint Utilities; as of November 2020, for the other utilities.
Sources:
For the Joint Utilities: California DG Stats for MW by customer type (https://www.californiadgstats.ca.gov/charts/); Joint Utilities' data for NEM as % of peak demand (Page 1 of Attachment A to the 3-15-2021 Joint Proposal of PG&E, SDG&E and SCE in Docket R.20-08-020; EIA data for residential customers with PV, customer counts for residential customers, and participation rates (861 data)).
For the other utilities: NCCETC Study, Table 2.

As observed in a 2017 study on NEM cost shifts: in "states or utilities with particularly high distributed solar penetration levels and with NEM set at full retail prices, the impacts on non-participants' electricity price effects may be relatively significant but depend critically on the value of solar and underlying rate structure."[52]

Given the high penetration rates for residential PV in California, the NEM 2.0 rate design with its compensation of exports at retail rates has led to an enormous cost shift from NEM customers to non-participating customers: the Joint Utilities estimate it at $3.4 billion per year (as explained further in

[52] "Four utilities, all in Hawaii, currently have solar penetration rates on the order of 10% of electricity sales, and three other states are projected to reach this mark by 2030. Assuming a utility value of solar ranging from 50% to 150% of its average cost of service, this level of distributed solar would yield a maximum 5% increase in retail electricity prices (e.g., 0.5 cents/kWh for a utility with electricity prices otherwise equal to the national average), under net metering with purely volumetric rates. Under rate structures with fixed charges or demand charges—as are already common, particularly for commercial customers—the effects would be shifted downward." Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," Lawrence Berkeley National Laboratory, January 2017, page 29, https://www.osti.gov/servlets/purl/1469160.

Chapters 1 and 3). This cost shift will grow in the absence of a new successor tariff that ensures that new rooftop solar customers pay more (or all) of their fair share of system costs.

The Joint Utilities' $3.4 billion/year estimate is reinforced by the findings in the 2021 "Net-Energy Metering 2.0 Lookback Study" prepared by Verdant Associates.[53] The Lookback Study found that the NEM 1.0 and 2.0 tariffs for on-site solar and solar-paired storage NEM customers produce higher costs than benefits from both a total societal and ratepayer impact point of view (and especially for non-participating residential customers).[54] The overly attractive value proposition for residential customers under NEM 1.0 and 2.0 rates is also apparent in the short payback periods they enjoy, especially in light of the 20-year period during which they may continue to take service under NEM rates:

Table II-2
Existing NEM 2.0 Program -
Illustrative Estimated Payback Periods for Participating Customers

Utility	Estimated Payback Period (Standalone Solar)	Estimated Payback Period (Solar + Storage)	Time Period During Which this NEM Rate is Available to Each NEM 2.0 Customer
PG&E	4 years	6 years	20 years
SCE	4 years	7 years	20 years
SDG&E	3 years	4 years	20 years
Source: Table 2 of Attachment A to the 3-15-2021 Joint Proposal of PG&E, SDG&E and SCE in Docket R.20-08-020.			

3. <u>Other NEM states that have reformed their NEM programs have continued to see strong customer adoption of rooftop solar</u>

Some utilities in other states, including some with much lower rooftop-solar penetration rates than the Joint Utilities', have already addressed such cost shifts (and overly generous compensation to participating NEM customers) by adopting successor tariffs. Notably, reforms have been adopted in

53 Verdant Associates, "Net-Energy Metering 2.0 Lookback Study," Submitted to the California Public Utilities Commission Energy Division, January 21, 2021 (hereafter referred to as the "NEM 2.0 Lookback Study").

54 NEM 2.0 Lookback Study, Tables 1-2 and 1-3.

Arizona (for APS), Hawaii (for HECO), Nevada (for NV Energy), New York (National Grid), and South Carolina (for Duke Energy[55]).[56]

Although the details of NEM successor tariffs have varied (*see* Table II-3), all of them have implicitly or explicitly addressed cost shifts and attempted through their reforms to better align the interests of participating customers, non-participating customers and the system as a whole. For example, the Hawaii Public Utilities Commission (HPUC) concluded in 2014 that the "distributed solar PV industry in Hawaii will, out of necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the [Hawaiian Electric] HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system, and hopefully becomes a key contributor to Hawaii's grid modernization."[57]

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[55] On May 19, 2021, the South Carolina Public Service Commission approved the settlement proposal for Solar Choice Metering Tariffs (Docket 2020-264-E/2020-265-E) submitted by Duke Energy Carolinas, Duke Energy Progress, North Carolina Sustainable Energy Association, Southern Environmental Law Center on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever; and Vote Solar. *See:* https://dms.psc.sc.gov/Attachments/Matter/f7ef21b9-d3c3-464c-9e71-f498d50e168a.

[56] Note that the NCCETC study also examined the rates of other California utilities (i.e., LADWP, PacifiCorp and SMUD) even though they had not undergone NEM tariff reforms.

[57] Hawaii Public Utilities Commission, Order No. 32053, p. 49 – 50. Hawaii Public Utilities Commission Docket No. 2011-0206. https://puc.hawaii.gov/wpcontent/uploads/2014/04/Order-No.-32053.pdf, as quoted in the NCCETC Study, page 19, footnote 35.

Table II-3
NEM Successor Tariffs in Selected States with NEM Reforms
APS, HECO, NV Energy, National Grid, Duke Energy Carolinas

Utility	(A) Netting Interval	(B) Export Credit Rate	(C) Net Excess Generation	(D) Additional Fees	(E) Low- and Moderate-Income Provisions	(F) Treatment of Legacy NEM Customers
AZ: Arizona Public Service (APS)	Instantaneous	NEM shifting to net billing. Export comp is phasing down to avoided cost; current rate is $0.1045/kWh	Carries forward indefinitely or paid out	DG Grid Access Fee or On-Peak Demand Charge	N/A	Existing customers are grandfathered for 20 years after interconnection date
CA: LADWP	Monthly	NEM: Export comp at retail rate	Carries forward indefinitely	None for NEM, but all customers have a "power access" charge based on the customer's maximum monthly kWh use	Leases rooftop space for utility-owned solar panels); SGIP available to LADWP customers on a SoCalGas account	No NEM rate reform, so all NEM customers may continue service on NEM
CA: PacifiCorp	Instantaneous	Net billing: export comp at time-varying: On-Peak: $0.0486/kWh Off-Peak: $0.0370/kWh	Carries forward, but expires at end of annual period	Basic monthly charge for facilities ($7.53)	N/A	NEM customers grandfathered to 2040
CA: SMUD	Monthly	NEM with export comp at retail rate (mandatory TOU rate as of 2018)	Carries forward indefinitely or paid out at special rate	System Infrastructure Fixed Charge: $22.25	N/A	No NEM rate reform although under discussion
HI: HECO Utilities (Customer Grid Supply Plus (CGS+) incl grid control)	Instantaneous	Net billing: $0.1008/kWh to $0.2080/kWh (varies by island, with periodic updates)	Carries forward and reconciled at export rate at end of annual period	Residential minimum bill ($25) which can't be offset	N/A	NEM customers remain on legacy NEM
HI: HECO Utilities (Smart Export – solar paired with storage)	Instantaneous	Net billing: $0.11/kWh to $0.2079/kWh (varies by island; no comp for exports during 9am-4pm)	Carries forward but expires at end of monthly billing period	Residential minimum bill ($25) which can't be offset	N/A	NEM customers remain on legacy NEM
NV: NV Energy	Monthly	NEM, but with gradual step-down of retail rate for net excess generation	Carries forward indefinitely	None	N/A (but under development/ proposal)	NEM customers are grandfathered
NY: National Grid (Mass Mkt – for smaller systems)	Monthly	NEM: Retail rate	Carries forward indefinitely	Customer Benefit Contribution, at $1.15/kW but not to address cost shift	Multiple state programs for low-income customers	No NEM rate reform, so all NEM customers may continue on NEM
NY: National Grid (Value of Distributed Energy Resources)	Hourly	Value of DER rate (with periodic update of the elements and payment levels in the value stack)	Carries forward indefinitely	50% of Customer Benefit Contribution, at $1.15/kW but not to address cost shift	Multiple state programs for low-income customers	VDER customers may stay on rate
SC: Duke Energy (now approved)	Monthly, by time-of-use period	Time-varying: Critical Peak: $0.25/kWh On-Peak: $0.1517-$0.1584/kWh Off-Peak: $0.0876-$0.0953/kWh; Super Off-Peak: $0.0603-$0.0699/kWh	Credited at avoided cost rate	Minimum Bill, increased Basic Facilities Charge, Non-Bypassable Charge, Grid Access Fee	N/A	Existing customers are grandfathered until 2025 or 2029 (tied to when they installed their rooftop PV)

In approving NEM successor tariffs, state regulators in Arizona, Hawaii, Nevada, New York, and South Carolina have approved rate mechanisms (such as a grid access charge; modification of the pricing of exports and net surplus compensation; the frequency of netting periods; and treatment of legacy customers on early NEM rate plans) like those included in the Joint Utilities' proposal.[58]

Note that in May 2021 and at the direction of the HPUC, HECO submitted a proposal to shift to a permanent successor to the previously approved NEM reform tariff and to transition existing NEM (called Distributed Energy Resources (DER)) customers to the permanent tariff.[59] A central element of the proposal is to include three time-varying periods (off-peak, midday and on-peak) for compensating customers for exports to the grid, to set export compensation for the average marginal cost of generation in 2021 for each time period, to update the rate every two years, to offer options for the utility to control the timing of exports, and to transition existing NEM customers to the new tariff in seven years. In offering this proposal, HECO explained that "time variant compensation is designed to

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58 For example, Hawaii and Arizona have tied export compensation to avoided costs:

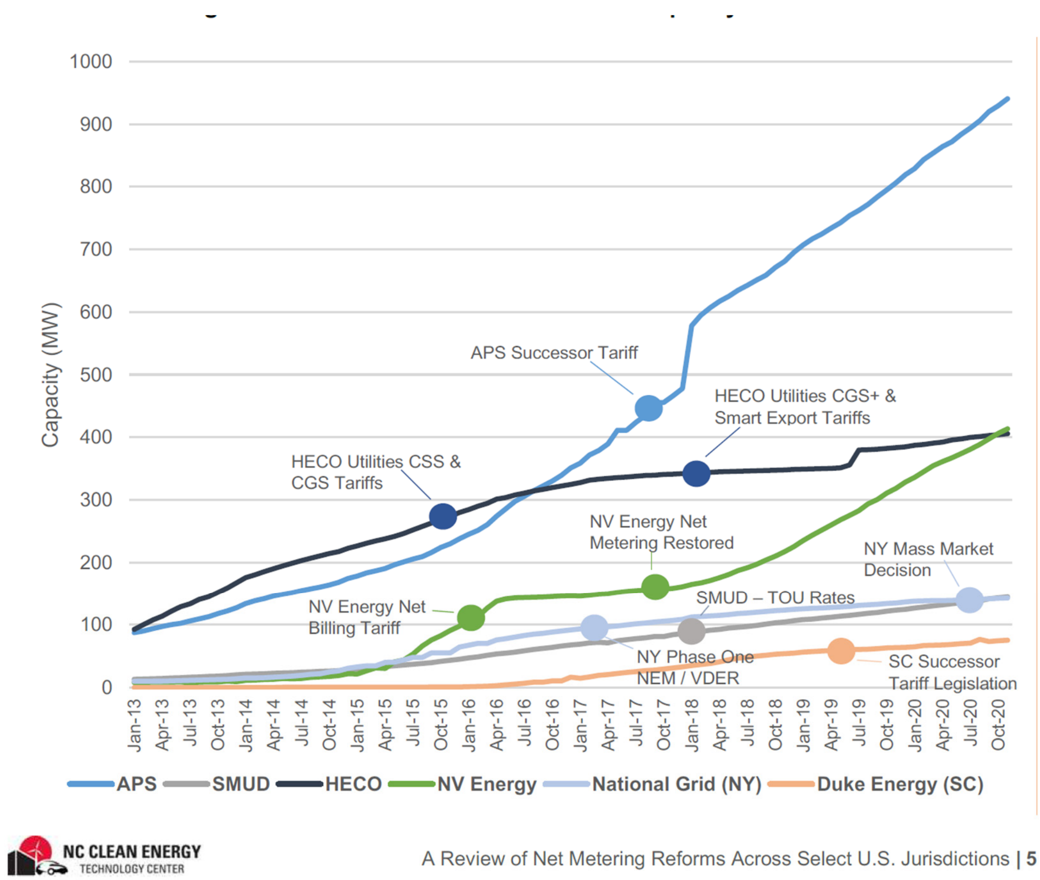
- Hawaii has closed full NEM service to new applicants of Hawaiian Electric Company (HECO) and replaced full NEM service with three other tariff options: "the customer self-supply (CSS) option, the customer grid-supply (CGS) option, and a time-of-use (TOU) tariff program similar to NEM, but at a reduced credit rate….The CGS option is functionally similar to NEM. Customers export excess energy to the grid and receive a credit. The difference between NEM and CGS is that the CGS credit is set to approximate the relative value of the energy to the system and the credit does not need to be tied to retail rates. The net effect of the proposed CGS tariff is to reduce the solar credit that customers receive for self-generation from 30 cents/kilowatt-hour (kWh) under traditional net metering to ~15 cents/kWh, which is closer to HECO's avoided cost compared to the least cost alternative generation resource. In addition, the minimum residential customer bill was increased from $17 to $25."
- "As of December 2016, Arizona replaced its NEM program with a net billing program. In net billing, a distributed generation system owner consumes self-generated electricity in real time that displaces retail rate utility electricity; however, excess generation exported to the grid is valued at a non-retail, predetermined avoided cost rate. Each utility will determine its specific avoided cost rate. Net billing is similar to NEM, but a net billing arrangement does not allow excess generation to be credited to the distributed generation owner's future utility bills; the excess generation is "sold" to the grid at the predetermined rate and that credit is applied to the billing cycle." A.C. Orrell, J.S. Homer and Y. Tang, "Distributed Generation Valuation and Compensation," Pacific Northwest National Laboratory (PNNL), February 2018 (herein referred to as "PNNL DG Valuation and Compensation Study") pages 14-15 (with citations in the original omitted in the quoted text above), https://www.districtenergy.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=0103ebf1-2ac9-7285-b49d-e615368725b2&forceDialog=0.

59 Hawaiian Electric letter to the Hawaii Public Utilities Commission, Hawaiian Electric's DER Program Track Final Proposal, Docket No. 2019-0323 (Instituting a Proceeding to Investigate Distributed Energy Resource Policies), May 3, 2021.

provide price signals to motivate customers to export energy when it is most valuable to the grid, and therefore the most valuable to customers."[60]

As shown in Figure II-10, solar PV capacity has continued to increase in the states with reformed NEM tariffs, even with longer payback periods (*see* Figure II-10). Although the rate of adoption tended to initially slow after implementation of successor tariffs, the markets continue to demonstrate positive growth in cumulative capacity.[61]

Figure II-10
Residential Solar Net-Metered Capacity Over Time
(Pre- and Post-NEM Reforms)



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[60] Hawaiian Electric letter to the Hawaii Public Utilities Commission, Hawaiian Electric's DER Program Track Final Proposal, Docket No. 2019-0323 (Instituting a Proceeding to Investigate Distributed Energy Resource Policies), May 3, 2021, pp 1-2.

[61] NCCETC Study, Table 3.

Table II-4
Estimated Simple Payback Periods for Customers After Modification of NEM Tariffs by their Utilities

Utility	Payback Period Estimate Using Energy Sage System Cost Data	Payback Period Estimate Using Tracking the Sun System Cost Data
APS	9.6	14.4
HECO	6.0 - 9.0	6.0 - 9.06
NV Energy	11.6	19.5
National Grid NY	11.3	18.5
LADWP	6.6 - 7.1	8.9 - 9.6
SMUD	12.9	17.3
Duke SC	19.3	n/a
	Payback for Standalone Solar	
PG&E	4	
SCE	4	
SDG&E	3	

Notes: *
Cost data for Hawaii is unavailable from EnergySage and Tracking the Sun. The Hawaii analysis uses average system cost data from SolarReviews. Tracking the Sun does not include cost data for South Carolina.
Sources:
For the Joint Utilities: Table 2 of Attachment A to the 3-15-2021 Joint Proposal of PG&E, SDG&E and SCE in Docket R.20-08-020; For the other utilities: NCCETC Study, Table 2.

4. <u>Based on several trends, solar adoption will remain strong even with reform</u>

Trends in the solar market and industry and in consumer preferences will enable the Commission to reform NEM 2.0 and will ensure *sustainable* growth in deployment of behind-the-meter renewable generation as required by AB 327. Even SEIA, the Solar Energy Industry Association, points to key drivers of continued growth: a now-strong national presence, a healthy maturation of the industry and an outlook affected by declining PV costs, climate policies, customer demand, and new product offerings.[62]

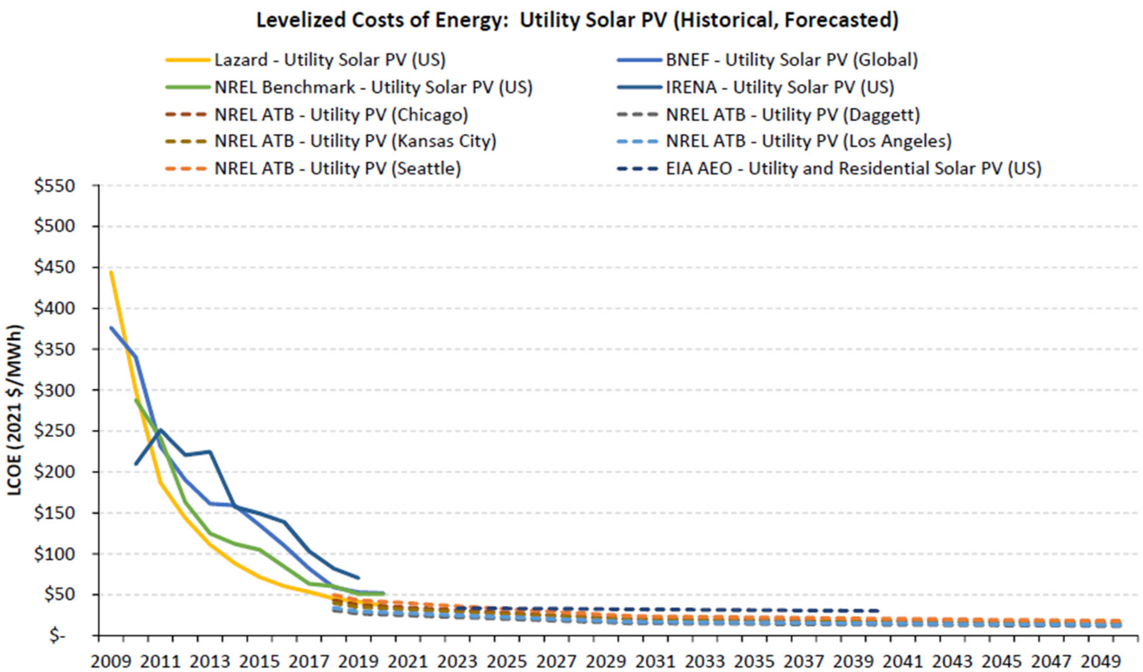
a) <u>Trend 1: Solar costs have declined substantially since the adoption of NEM and are expected to continue to go down in the future</u>

In the 25 years since California adopted its NEM program, the installed costs of new solar PV systems have declined substantially. Although estimates of levelized cost of solar vary, the cost of new rooftop solar has dropped from a range of approximately $320-$530 per MWh a decade

[62] https://www.seia.org/solar-industry-research-data, accessed June 14, 2021.

ago to approximately $150-$190 per MWh in 2019. (The cost of utility-scale solar installations have dropped even further, to around $50-$75 per MWh as of 2019.) Industry analysts expect costs to continue to drop, although at a slower rate in upcoming years. (Figure II-11 and Figure II-12 show the historical actual and estimates of future levelized cost of energy for utility-scale solar PV and residential solar PV systems, respectively.)

Figure II-11
Levelized Costs of Energy: Utility Solar PV (Historical, Forecasted)



Sources:
[1] Lazard, Levelized Cost of Energy Analysis — Version 14.0.
[2] Bloomberg NEF, Scale-up of Solar and Wind Puts Existing Coal, Gas at Risk.
[3] NREL, Benchmark U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020.
[4] NREL, Annual Technology Baseline Data.
[5] EIA, Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021.
[6] IRENA, Renewable Power Generation Costs in 2019.

Such continued decreases in the installed cost of PV systems are anticipated to result from many factors, as explained in a recent National Renewable Energy Laboratory (NREL) Q2/Q3 2020 Solar Industry Update and shown in Figure II-12: "Solar PV: Indicative Cost Reductions by Type of Cost".[63] These factors include: removal of tariffs; reduction in hardware that translates to

[63] David Feldman and Robert Margolis, "Q2/Q3 2020 Solar Industry Update," NREL, December 8, 2020, https://www.nrel.gov/docs/fy21osti/78625.pdf

lower supply chain, profit, and sales tax costs; streamlined permitting (and interconnection); easier customer acquisition; better labor practices.[64] (Recent installer surveys indicate cost breakdowns that closely match NREL's national averages, except for labor costs (which came out as a higher percentage) and customer acquisition costs (which came out as a lower percentage.)[65] Also, doing business during the COVID-19 pandemic motivated many solar companies to shift to online marketing and sales, which lowers customer-acquisition costs compared to traditional sales models.[66] "The shift to fully remote sales is likely to be permanent for some."[67]

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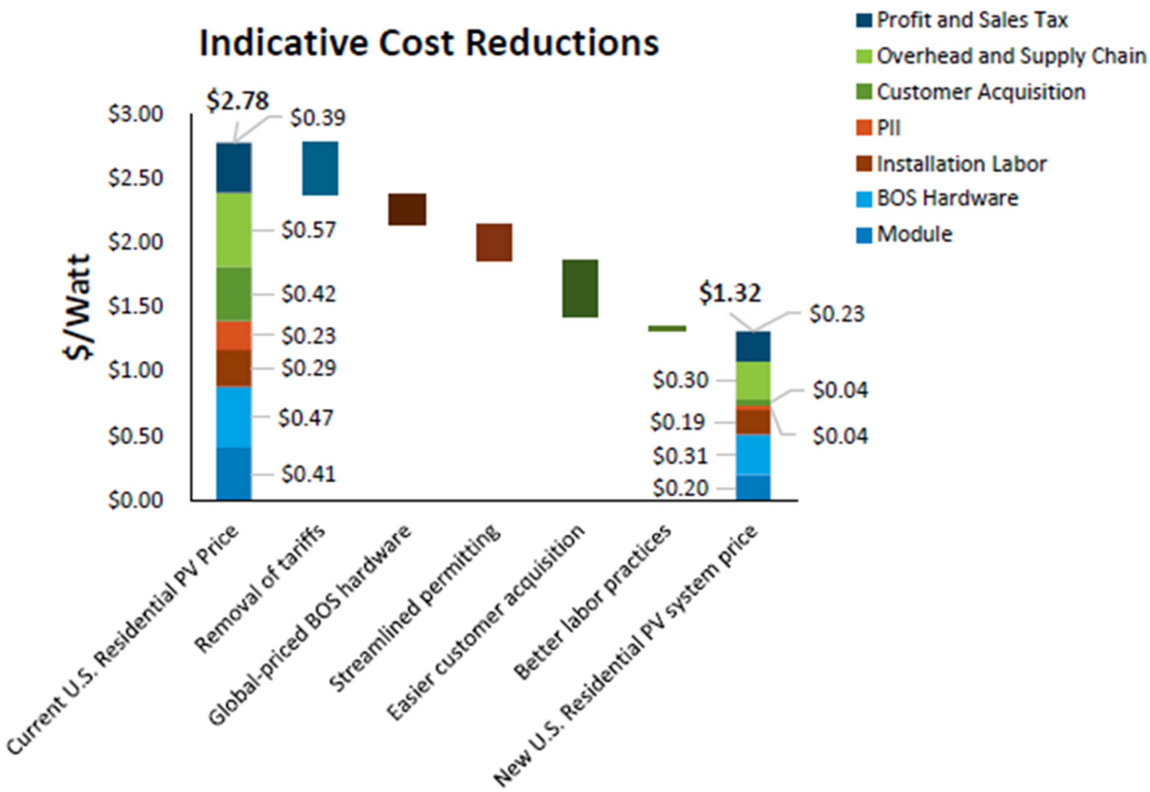
[64] David Feldman and Robert Margolis, "Q2/Q3 2020 Solar Industry Update," NREL, December 8, 2020, pp. 53-54.

[65] EnergySage, "Solar Installer Survey: 2020 Results," March 2021, page 13, https://www.energysage.com/data/#reports.

[66] EnergySage, "Solar Installer Survey: 2020 Results," March 2021, https://www.energysage.com/data/#reports.

[67] Julian Spector, "Coronavirus is Forcing Homes Solar Companies to Sell Virtually. Maybe That's a Good Thing," GTM: Greentech Media, April 6, 2020, https://www.greentechmedia.com/articles/read/coronavirus-is-forcing-solar-companies-to-sell-virtually-maybe-thats-a-good-thing.

Figure II-12
Solar PV: Indicative Cost Reductions by Type of Cost[68]



b) **Trend 2: Residential storage has experienced cost declines and offers a powerful combination when paired with solar**

In the 25 years since California adopted its NEM program, the installed costs of residential and other small-scale storage have also declined, in large part due to technology improvements in lithium-ion batteries. These price trends have helped boost the attractiveness of storage as a new service and product offering in conjunction with on-site solar, even for residential consumers. Consumers report they are interested in solar for cost savings and storage in large part for

68 "NRELQ2/Q3 Solar Industry Update

resilience and back-up power supply, providing a potentially powerful combination.[69] As of 2020, 242 MW are located in the service territories of the Joint Utilities.[70]

Lithium-ion batteries – the most common technology used in small-scale storage systems[71] – have shown cost reductions in recent years. Massachusetts Institute of Technology (MIT) researchers recently estimated that the real price of these batteries dropped 97% since 1991, with a 13% average annual improvement in the price per energy capacity between 1992 and 2016.[72] Figure II-13: "Price Decreases in Lithium-Ion Batteries: Historical and Projected" (from the MIT study) summarizes cost trends from other research studies for the period since 1991, when such lithium-ion batteries began to enter the market. The two take-aways from this complicated figure are that (a) lithium-ion battery prices have declined significantly over the past three decades, and (b) the authors' "simple projections"

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[69] Pew Research Center, "More U.S. homeowners say they are considering home solar panels, December 17, 2019, https://www.pewresearch.org/fact-tank/2019/12/17/more-u-s-homeowners-say-they-are-considering-home-solar-panels/ and https://www.pewresearch.org/wp-content/uploads/2019/12/Ft_19.12.17_SolarPanels_TOPLINE-1.pdf; Insight, "Going Solar Isn't All About Saving Money for Low-Income Consumers," Energy Policy Institute at the University of Chicago, January 15, 2020, https://epic.uchicago.edu/insights/going-solar-isnt-all-about-saving-money-for-low-income-consumers/; Michele Lerner, "Solar panel use heats up as installation costs fall," The Washington Post, May 27, 2021, https://www.washingtonpost.com/realestate/solar-panel-use-heats-up-as-installation-costs-fall/2021/05/26/b55a2ea4-8825-11eb-8a8b-5cf82c3dffe4_story.html?utm_source=rss&utm_medium=referral&utm_campaign=wp_homepage; Provoke Insights, "What Motivates Consumers to Purchase Solar Power?" 2017, https://www.prnewswire.com/news-releases/what-motivates-consumers-to-purchase-solar-power-300556134.html; J. Farrell, "Energy Democracy in 4 Powerful Steps," Institute for Local Self-Reliance, March 1, 2017, https://ilsr.org/energy-democracy-in-4-steps/.

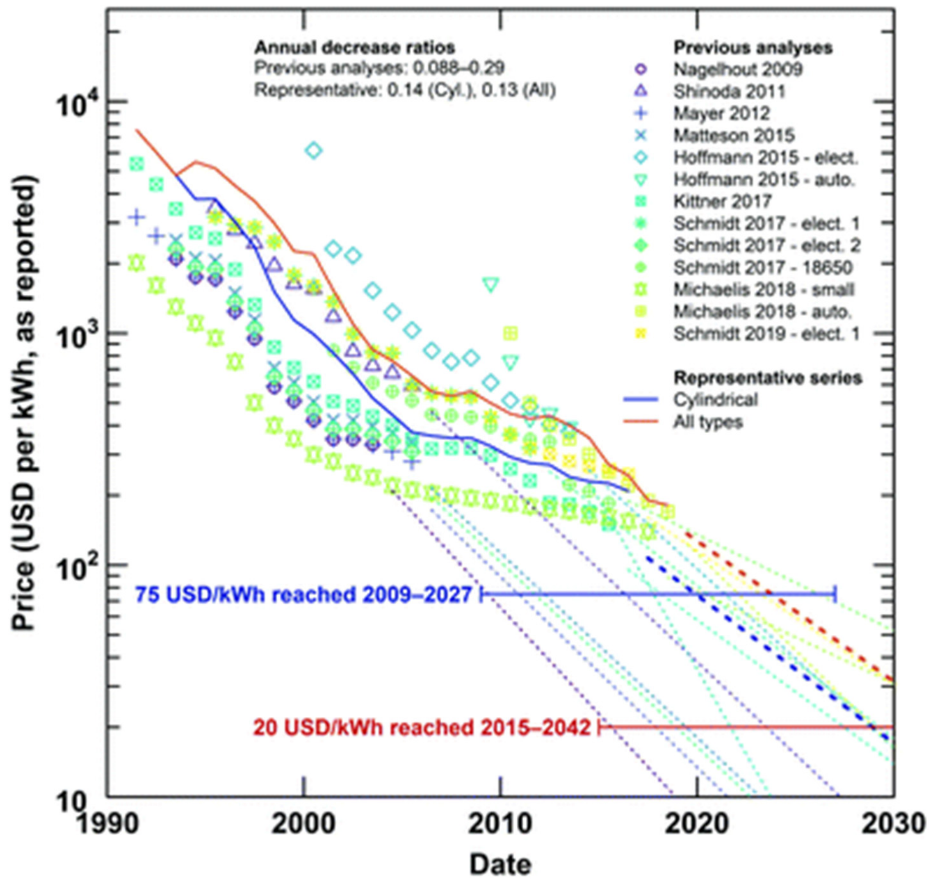
[70] Source data: EIA, 861 datafile on net metering customers by utility. https://www.eia.gov/electricity/data/eia861/.

[71] "Lithium-ion batteries are widely available and mass-produced globally although manufacturing is concentrated in Asia. They are modular and can be installed in multiple scales ranging from a few kilowatts at residential scale to hundreds of megawatts for bulk system applications. Li-ion batteries can provide high power for short-duration applications (e.g., frequency regulation) and up to (and sometimes more than) four hours of energy capacity for longer-duration applications (e.g., transmission or distribution network investment deferral)." BloombergNEF and the Business Council for Sustainable Energy, "Sustainable Energy in America 2021 Factbook," page 86, https://bcse.org/factbook/,

[72] Micah Ziegler and Jessika Trancik, "Re-examining rates of lithium-ion battery technology improvement and cost decline, Energy & Environmental Science, 2021 (hereafter, the "Ziegler/Trancik Study") https://pubs.rsc.org/en/content/articlepdf/2021/ee/d0ee02681f?page=search. The researchers analyzed 90 different studies of cost and performance of lithium-ion batteries and harmonized the data so as to develop an overall picture of price trends.

of future cost declines suggest a nearly "30 year range for reaching 20 USD kWh [*i.e.*, from a few years ago through 2042]."[73]

Figure II-13
Price Decreases in Lithium-Ion Batteries: Historical and Projected



Zeigler/Trancik Study (2021)

Other market analysts also anticipate future cost reductions, although at a slower pace than in the past three decades: "BloombergNEF forecast[s] battery costs falling under US$100/kWh in 2024 and hitting around US$60/kWh by 2030... Likewise, Bernstein analysts have projected 2024 as the year that mainstream electric vehicles reach cost parity with gas and diesel vehicles, while electric vehicle leaders in the sector may reach the same point by 2022 or 2023."[74]

[73] Ziegler/Trancik Study.

[74] Kip Keen, "As battery costs plummet, lithium-ion innovation hits limits, experts say," May 14, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/as-battery-costs-plummet-lithium-ion-innovation-hits-limits-experts-say-58613238.

The most recent versions of Lazard's Levelized Cost of Storage include estimates for different storage use cases, including one for behind-the-meter residential PV paired with storage. The cost ranges for that use case in recent years show overall improvement in the level and range of costs. (*See* Table II-5.)

Table II-5
Unsubsidized Levelized Cost of Storage (LCOS) – Low/High Cost Range Estimates
Behind the Meter Residential (PV + Storage) - Energy ($/MWh)

Year	2018	2019	2020
Version of the Lazard LCOS Analysis (Version #)	4.0	5.0	6.0
Low End of Price Range ($/MWh)	$476	$457	$406
High End of Price Range ($/MWh)	$735	$663	$506

Notes re: capital cost assumptions:
Lazard LCOS 4.0: range of $2,961/kW-$3,270/kW
Lazard LCOS 5.0: $2,875/kW
Lazard LCOS 6.0: $2,675/kW
Source:
Lazard LCOS 4.0 for 2018 prices (page 11) - (Lithium battery), https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.
Lazard LCOS 5.0 for 2019 prices (page 4), https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
Lazard LCOS 6.0 for 2020 prices (page 6), https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf

Storage contributes to the value proposition in several ways that may be increasingly accessible as the combined cost of solar-paired storage decline. Solar-paired storage is even more attractive when combined with rate designs that provide time-differentiated rates for consumption, with other policies and programs creating incentives for adoption, and in light of the functionalities afforded by the combination of the two technologies.

c) <u>Trend 3: Valuing customer choice and preferences</u>

Electricity consumers want and expect reliable and affordable power. They also want the electric system to provide resilient and safe supply, clean and sustainable power, and equitable access to electricity.[75]

Residential electricity consumers report many reasons for choosing solar, either as a stand-alone installation or combined with storage. For solar, the principal motivation for household

[75] National Academies of Sciences, Engineering and Medicine, "The Future of Electric Power in the United States," 2021, pages 18-19, https://www.nap.edu/download/25968.

adopters is to save money on and/or manage their electricity bills (with secondary factors such as taking advantage of the declining cost of solar, helping the environment, becoming independent of the grid, etc.).[76]

d) Trend 4: Resiliency as an adoption driver

The same principal motivation also tends to drive households' adoption of storage, along with one other significant factor: ensuring access to electricity during power outages.[77]

> Resilience reigns supreme. 65% of [storage] installers say that resilience – having backup power in the event of a major storm event or power outage – is the primary driver of consumer interest in storage, a sizable increase from 2019. Interestingly, while a fifth of installers cited financial benefits [to consumers] as the primary driver for storage in 2019, only 8% of respondents rated financial savings as the primary driver of storage interest in 2020.[78]

The same study found that storage interest is on the rise. From the climate change driven wildfire-related outages and public safety power shutoff (PSPS) events on the West Coast to the millions of outages due to Hurricane Isaias on the East Coast, 2020 provided many reasons for homeowners to seek resilience. As a result, consumer interest in energy storage surged nationwide to

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[76] Pew Research Center, "More U.S. homeowners say they are considering home solar panels, December 17, 2019, https://www.pewresearch.org/fact-tank/2019/12/17/more-u-s-homeowners-say-they-are-considering-home-solar-panels/ and https://www.pewresearch.org/wp-content/uploads/2019/12/Ft_19.12.17_SolarPanels_TOPLINE-1.pdf; Insight, "Going Solar Isn't All About Saving Money for Low-Income Consumers," Energy Policy Institute at the University of Chicago, January 15, 2020, https://epic.uchicago.edu/insights/going-solar-isnt-all-about-saving-money-for-low-income-consumers/; Michele Lerner, "Solar panel use heats up as installation costs fall," The Washington Post, May 27, 2021, https://www.washingtonpost.com/realestate/solar-panel-use-heats-up-as-installation-costs-fall/2021/05/26/b55a2ea4-8825-11eb-8a8b-5cf82c3dffe4_story.html?utm_source=rss&utm_medium=referral&utm_campaign=wp_homepage; Provoke Insights, "What Motivates Consumers to Purchase Solar Power?" 2017, https://www.prnewswire.com/news-releases/what-motivates-consumers-to-purchase-solar-power-300556134.html; J. Farrell, "Energy Democracy in 4 Powerful Steps," Institute for Local Self-Reliance, March 1, 2017, https://ilsr.org/energy-democracy-in-4-steps/.

[77] "Consumer preference on EnergySage confirms this trend: after asking to receive storage quotes on EnergySage, 69 percent of consumers say they're interested in storage for backup power." EnergySage, Solar Marketplace Intel Report, May 2021, https://www.energysage.com/data/; Terance Harper, "Four reasons residential solar + storage installations are surging in the U.S." Solar Builder, January 25, 2021, https://solarbuildermag.com/training/four-reasons-residential-solar-storage-installations-are-surging-in-the-u-s/

[78] EnergySage, "Solar Installer Survey: 2020 Results," March 2021, https://www.energysage.com/data/.

nearly half of all customers in 2020, according to survey respondents. This trend is clearest in states like California (51% interest) and hurricane-impacted North Carolina (55% interest).[79]

With so many trends underway – prices dropping for both residential solar and storage systems, electricity prices likely to go up, increasing reliance on electric appliances and equipment, extreme weather events on the rise, and growing concern for climate change and local air pollution – many households will be motivated to add BTM systems even if there are reforms to the current NEM tariff.

e) <u>Trend 5: The solar industry has matured since the early decades of the NEM program</u>

Several solar industry trends that were not present 25 years ago will help drive continued adoption of behind-the-meter programs: a now-strong national presence, a healthy maturation of the industry and an outlook affected by declining PV costs, climate policies, customer demand, and new product offerings. Large solar companies and smaller solar installers are positioned to continue to meet customer demand for rooftop solar through a variety of product and service offerings.

Recent public communications from the solar industry, through SEIA, point to a number of drivers of continued growth in the market for rooftop solar: a now-strong national presence, a healthy maturation of the industry and an outlook affected by declining PV costs, climate policies, customer demand, and new product offerings.[80]

- **"The U.S. Solar Industry is a 50-State Market"**
  - "While California has traditionally dominated the U.S. solar market, other markets are continuing to expand rapidly. In 2020, states outside of California made up their largest share of the market in the last decade, led by rapid growth in Florida and Texas. As the price of solar continues to fall, new state entrants will grab an increasingly larger share of the national market."

[79] EnergySage, "Solar Installer Survey: 2020 Results," March 2021, https://www.energysage.com/data/.

[80] The statements below are quotations from the SEIA website, accessed April 1, 2021: https://www.seia.org/solar-industry-research-data.

- **“Solar industry Growing at a Record Pace”**
  - “Solar energy in the United States is booming: Along with our partners at Wood Mackenzie Power & Renewables and The Solar Foundation, SEIA tracks trends and trajectories in the solar industry that demonstrate the diverse and sustained growth of solar across the country.”
- “**Massive Growth Since 2000 Sets the Stage for the Solar+ Decade”**
  - “In the last decade alone, solar has experienced an average annual growth rate of 42%. Thanks to strong federal policies like the solar Investment Tax Credit, rapidly declining costs, and increasing demand across the private and public sector for clean electricity, there are now more than 97 gigawatts (GW) of solar capacity installed nationwide, enough to power nearly 18 million homes.”
- **“Solar’s Share of New Capacity has Grown Rapidly”**
  - “Solar has ranked first or second in new electric capacity additions in each of the last 8 years. In 2020, 43% of all new electric capacity added to the grid came from solar, the largest such share in history and the second year in a row that solar added the most generating capacity to the grid. Solar’s increasing competitiveness against other technologies has allowed it to quickly increase its share of total U.S. electrical generation - from just 0.1% in 2010 to over 3% today.”
- **“Growth in Solar is Led by Falling Prices”**
  - “The cost to install solar has dropped by more than 70% over the last decade, leading the industry to expand into new markets and deploy thousands of systems nationwide. Prices as of Q4 2020 are at their lowest levels in history across all market segments. An average-sized residential system has dropped from a pre-incentive price of $40,000 in 2010 to roughly $20,000 today, while recent utility-scale prices range from $16/MWh - $35/MWh, competitive with all other forms of generation.”
- **“More Aggressive Growth Needed to Reach Climate Goals”**
  - “Expected growth over the next 10 years puts the solar market in reach of ambitious clean energy goals set by industry and the Biden administration, more work is needed to achieve the pace required for a 100% clean energy electricity system. Annual installs will need to grow from 20 GW in 2020 to over 80 GW by 2030, with cumulative totals nearing 600 GW by the end of the decade. A combination of private sector innovation and stable, long-term public policy will set the solar industry on a path to achieving these more aggressive goals to address climate change and decarbonize the economy.”

- **"Solar PV Growth Forecast"**

  - "Despite obstacles posed by the pandemic, the U.S. solar market set a new annual record with 19.2 GW installed in 2020. With an historic utility-scale pipeline and recovering demand in the residential and non-residential segments, the industry is set for a series of record years until 2024, when the [federal investment tax credit] is scheduled to fully step down. Barring new policy developments at the state and federal levels, industry growth through the end of the decade is premised on continued price declines and growing demand from utilities, states, corporations, and distributed solar customers. Over the next 10 years, 324 GW will be installed, 3 times the amount installed through 2020."

- **"Storage is Increasingly Paired with All Forms of Solar"**

  - "Homeowners and businesses are increasingly demanding solar systems that are paired with battery storage. While this pairing is still relatively new, the growth over the next five years is expected to be significant. By 2025, nearly 25% of all behind-the-meter solar systems will be paired with storage, compared to under 6% in 2020."

Other information similarly points to a positive outlook for the growth in the solar market, nationally and in California too. First, from a policy point of view, the California market for renewables, including customer-sited PV and other distributed generation, offers significant opportunities for growth (as explained in Chapter 1). These include the state's requirements to reach carbon neutrality by 2045, to rely on electrification over time as the power sector continues to reduce its GHG emissions and to gain efficiencies from substituting electric end uses for appliances, vehicles, and equipment that currently rely on fossil fuels, and to mandate rooftop solar on new buildings.

Second, major solar companies anticipate growth in customer adoption of solar and other DERs considering several trends. In a recent presentation to investors, Sunrun, for example, lists the following factors as driving growth and increased opportunity for financial returns: "Increasing retail utility rates; Deteriorating grid reliability; Declining solar and battery costs; Climate change; Home electrification; Electric vehicle penetration; Virtual power plants. Sunrun integrates solar, storage, electrification and virtual power plants into a smart solution for each home and community."[81]

[81] Sunrun Investor Presentation, March 2021, page 6, https://d1io3yog0oux5.cloudfront.net/_b5da1d121d15289fadaef124bd5eaf0f/sunrun/db/276/2243/pdf/Sunrun+Investor+Presentation+-+March+2021.pdf

As another example, SunPower, in its March 2021 investor presentation, anticipates substantial market growth through combining solar and storage, offering smart energy home management services, and shifting from sales of equipment to establishing long-term ("long-tail") relationships with customers through power purchase agreements and other leasing/financing mechanisms.[82]

Similarly, Sunnova points to the important role of "creating shareholder value by growing high quality, long-term contracted revenues" and "selling more services to new customers, and upselling additional services to existing customers," while also reducing costs and developing and managing grid and microgrid services.[83]

Figure II-14 shows information about the market value of several major solar companies (*i.e.*, Sunrun, Sunpower, Sunnova) that provide post-2016 products and services in California and elsewhere. These companies' recent financial statements indicate their diverse product offerings (solar and solar paired with storage) through customers' upfront purchase of equipment or through lease and power purchase agreements with customers. The latter product offerings tend to require a lot of upfront investment by the company, which may account for some near-term losses by big players that offer financing as well as installations.[84] But even with disclosures to investors about various risks that might affect each company's business, investors have shown overall confidence in these companies' performance over the past five years and their opportunities in the future. (Note that the overall trend in tech stocks, as reflected in the NASDAQ composite index has shown trends similar to these major solar companies, including net substantial gains since 5 years ago.)

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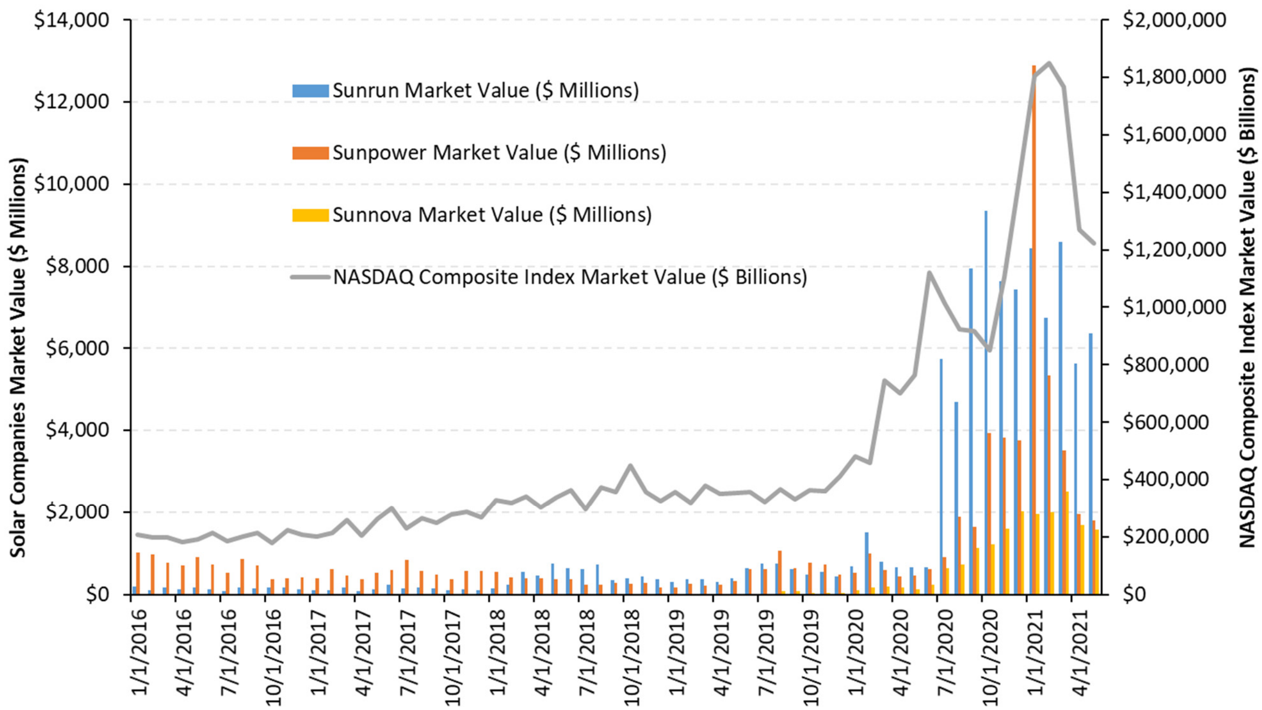
[82] SunPower, Investor Presentation, March 25, 2021, https://investors.sunpower.com/static-files/56ea5877-65fd-413d-850e-6b2f6574d600

[83] Sunnova, Fourth Quarter and 2020 Full Year Earnings presentation, February 24, 2021, https://s23.q4cdn.com/546214306/files/doc_financials/2020/q4/Sunnova-Q4-2020-Earnings-Slide-Deck-FINAL.pdf

[84] Peter Eavis and Ivan Penn, "Home Solar Is Growing, but Big Installers Are Still Losing Money," New York Times, January 4, 2021, updated May 28, 2021, https://www.nytimes.com/2021/01/04/business/energy-environment/rooftop-solar-installers.html.

Figure II-14
Market Value of Selected Major Solar Companies in the California Market
(Monthly, January 2016 through May 2021)



Sources:
[1] Yahoo Finance.
[2] Utility Dive, "Sunrun closes $3.2B Vivint Solar acquisition," October 8, 2020.

These three solar companies represent a subset of the companies involved in the distributed generation/rooftop solar market in California; the market also includes small companies that install solar systems. The cost trends in solar and solar paired with storage installations will tend to support households' continued adoption of new solar installations through small companies that are more like local construction contractors in the home-improvement or heating, ventilation and air-conditioner business, rather than the large solar companies that provide financing support and long-term power purchase agreements. The smaller firms rely on customer adoption and ownership, with loans provided by banks and credit unions.[85]

That outlook aligns well with the major factors that are driving continued demand for and deployment of rooftop solar in the state (as explained in Chapter 1).

5. <u>Current NEM structure adds to a growing affordability problem</u>

Many customers just want and need access to affordable electricity. The interests of these customers and those adopting BTM systems need not be in conflict, as long as the choices of the latter do not threaten the availability of affordable electricity service, especially for those for whom electricity bills are a heavy burden. For many households, just paying basic electricity bills is difficult:

> Energy burden is higher among low-income households than other income groups. The average energy burden of low-income households is not declining, and it continues to be high in particular geographies and socio-economic groups. Low-income households spend a higher proportion of their income on energy bills than any other income group …, spending on average three times more of their income on energy bills than higher income households ... This is true, even though low-income households consume less energy per capita than other households.[86]

Further, Black people pay more for energy than white people.[87] As the Commission reported in its 2019 Annual Affordability Report (April 2021):

> California households face significant disparities in their ability to afford essential utility services, even among households at similar points of the income distribution for a given area. The results of the analysis show stark geographical and income-based disparities…. [A] substantial number of households are located in areas where utility costs comprise an alarmingly high percentage of low-income household budgets. Approximately 11 percent of households are in the least affordable areas.[88]

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[85] Peter Eavis and Ivan Penn, "Home Solar Is Growing, but Big Installers Are Still Losing Money," *New York Times*, January 4, 2021, updated May 28, 2021, https://www.nytimes.com/2021/01/04/business/energy-environment/rooftop-solar-installers.html.

[86] *See*: M.A Brown, et al., "High Energy Burden and Low-Income Energy Affordability: Conclusions from a Literature Review," *Progress in Energy*, Vol. 2, 2020, page 9, https://dx.doi.org/10.1088/2516-1083/abb954.

[87] Eva Lyubich, "The Race Gap in Residential Energy Expenditures," Energy Institute at Haas, U.C. Berkeley, June 2020,

[88] CPUC's 2019 Annual Affordability Report, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/About_Us/Organization/Divisions/News_and_Outreach_Office/2019%20Annual%20Affordability%20Report.pdf.

Using the 2019 Annual Affordability Report's affordability index (which compares the cost of utility service to a household's adjusted income (*i.e.*, income available to pay for utility service after housing and other essential services are deducted)), there are parts of California where households pay a significant portion of their adjusted income on electricity service. Table II-6, "Selected California Areas where Household Have Relatively Unaffordable Electricity Service (2019)," illustrates the types of locations where poor households (*i.e.*, at the 20% income percentile in an area) pay a large share of their adjusted income on electricity service. Across California:

> 13 percent of households in the state are located in areas where low income households pay more than 15 percent of their disposable income on electricity service….[and in some of these areas households pay] significantly higher than 15 percent, indicating that low-income households in these areas spend a very large percentage of their non-disposable income on electricity. These areas include parts of Los Angeles, Chico, parts of the San Joaquin Valley, and parts of the San Francisco Bay Area where household incomes are extremely low.[89]

Every dollar these households pay in their electric bill is precious. A new study from LBNL researchers found that "[l]ow- and moderate-income (LMI) households are less likely to adopt rooftop solar photovoltaics (PVs) than higher-income households in the United States. As the existing literature has shown, this dynamic can decelerate rooftop deployment and has potential energy justice implications, in light of the cost-shifting between PV and non-PV households that can occur under typical rate structures and incentive programs."[90]

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[89] CPUC's 2019 Annual Affordability Report, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/About_Us/Organization/Divisions/News_and_Outreach_Office/2019%20Annual%20Affordability%20Report.pdf.

[90] Eric O'Shaughnessy, Galen Barbose, Ryan Wiser, Sydney Forrester, and Naïm Darghouth, "The impact of policies and business models on income equity in rooftop solar adoption," Nature Energy, January 2021, https://www.nature.com/articles/s41560-020-00724-2.epdf?no_publisher_access=1&r3_referer=nature.

Table II-6
Selected California Areas where Household Have Relatively Unaffordable Electricity Service (2019)

	Electricity Bill as % of Adjusted Income ("Affordability Ratio")	Income at 20th Income Percentile ($/yr)	Housing Costs at 20th Income Percentile ($/yr)	Distribution Utility	Average 2019 Residential Electricity Bill in that Utility's Service Territory
San Francisco County (Central) - South of Market & Potrero	35.5%	$17,986	$13,081	PG&E	$1,416
Los Angeles County (North Central) - Lancaster City	29.5%	$16,207	$11,263	SCE	$1,115
Fresno County (Central) - Fresno City (East Central)	27.8%	$14,714	$8,246	PG&E	$1,416
Butte County (Northwest) - Chico City	22.5%	$18,373	$10,014	PG&E	$1,416
Riverside County (East) - Indio, Coachella, Blythe & La Quinta	22.1%	$17,241	$8,921	SCE	$1,115
San Diego County (South Central) - San Diego City (Central/Mid-City)	21.4%	$19,506	$12,599	SDG&E	$1,187
Imperial County - El Centro City	18.9%	$16,390	$7,162	SCE	$1,115

Source:
Data on Affordability Ratio, Income at 20th Income Percentile, Housing Costs at 20th Income Percentile, and Distribution Utility are from page 35 of the CPUC's 2019 Annual Affordability Report, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/About_Us/Organization/Divisions/News_and_Outreach_Office/2019%20Annual%20Affordability%20Report.pdf
Data on Average Residential Bill is from EIA's 861 database for each utility (with the figure calculated as total residential revenues divided by total residential customers), https://www.eia.gov/electricity/data/eia861/

> A recent major literature review on affordability of electricity service found that "across the country, … net metering of solar rooftop installations are paid for in part with low-income ratepayer funds, but do not provide commensurate benefits to low-income ratepayers who do not have the resources to take advantage of these programs. If the energy industry, government agencies, NGOs and nonprofits do not address these unintentional consequences, low-income households will continue to suffer disproportionately from high energy burdens, failing most tests of distributive equity.[91]

In the context of considering the impact of the annual $3.4 billion NEM 1.0 and 2.0 cost shift to date (*see* Chapter 3), these dollars are borne by customers already burdened by the cost of utility service. The average NEM bill impact on CARE households — of ~$150/year in SDG&E's service territory, ~$110/year in PG&E's service area and ~$75/year in SCE's service territory — is a regressive means to subsidize the choices of other, more wealthy households.

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91 *See*: M.A Brown, et al., "High Energy Burden and Low-Income Energy Affordability: Conclusions from a Literature Review," Progress in Energy, Vol. 2, 2020, pages 3-4, https://dx.doi.org/10.1088/2516-1083/abb954.

Professor Borenstein and others have found:

> [T]he current system of recovering system costs through high volumetric prices is not only inefficient; it is also far less equitable than viable alternatives. It imposes a relatively large burden on lower- and average-income households while it recovers a shrinking fraction of system costs from higher-income households because of the diffusion of rooftop solar.[92]

Professor Borenstein continues:

> As wealthier households transition to rooftop solar, the fixed costs are distributed through a smaller volume of kilowatt-hours delivered, raising the costs even more for remaining, lower-income customers at a time when an increasing number of Californians are struggling to pay their utility bills. About eight million residents currently owe money to investor-owned utilities, according to a recent presentation by the California Public Utility Commission. This is especially concerning as rates are projected to rise again due to wildfire-related costs.[93]

6. <u>The subsidy provided by the NEM program should be reduced as a matter of sound policy design</u>

a) <u>Lessons learned for policy design: Subsidies that are important to kick-start markets should be withdrawn when they are no longer needed.</u>

A fundamental economic rationale for the use of subsidies is to enhance economic efficiency in the presence of market failures. Although typically subsidies come in the form of financial incentives provided by governments (which mean the provision of financial support from taxpayers in general to the group of parties that receive the subsidy), the concept also applies in situations where government entities (e.g., state legislatures or utility regulators) establish tariffs with compensation mechanisms where one group of customers (e.g., all ratepayers in a particular customer class) provide a financial transfer to another (e.g., to low-income or to wealthier customers). NEM is a typical example

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[92] Severin Borenstein, Meredith Fowlie, and James Sallee, "Designing Electricity Rates for An Equitable Energy Transition," Energy Institute at Haas, U.C. Berkeley and Next 10, February 23, 2021, page 5, https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf.

[93] Publication announcement: Severin Borenstein, Meredith Fowlie, and James Sallee, "Designing Electricity Rates for An Equitable Energy Transition," Energy Institute at Haas, U.C. Berkeley and Next 10, February 23, 2021, https://www.next10.org/publications/electricity-rates.

of the latter type of subsidy where non-participating (and often lower-income) customers provide a financial transfer to those customers on NEM rates.

The economic and public policy literature provides guidance for considering the elements of sound policy design, including the introduction and maintenance – and potential withdrawal – of financial subsidies. As markets mature and original rationales for their use shift conditions, subsidies may no longer be needed and should sunset, or at least move toward reliance on more market-based mechanisms to award support.

b) California has successfully managed transition of its past clean-energy policies

California can look to three of its clean-energy policies for constructive lessons on transitioning programs once they have done their important work to launch new markets. Each of the three cases — the California Solar Initiative (CSI), the California Clean Vehicle Rebate Program (CVRP), and California's early implementation of the Public Utilities Regulatory Policies Act (PURPA) — started out with relatively robust subsidies that were reduced over time, and nonetheless experienced sustainable growth in their intended outcomes (adoption of solar for CSI, purchases of clean vehicles for CVRP, and PURPA contracts with eligible power producers) even after the policy reforms were implemented.

First, CSI is an example of a program which helped to start up and condition the adoption of solar systems in the state and then peeled away the subsidies as the solar market hit various deployment milestones. The CSI Program was designed with a declining incentive structure to support the California solar market's growth while gradually reducing its reliance on subsidies. The CPUC divided the Program's overall megawatt goal into 10 incentive steps and assigned a target capacity cap in each step. Incentive rates were based on dollars per-watt or cents per-kilowatt-hour. As the market matured, it was expected solar system costs would drop, and so incentives offered through the program declined. The MW targets in each incentive step level were assigned to particular customer classes (residential, commercial, and government / non-profit) and allocated across the three Investor Owned Utility (IOU) service territories, in proportion with each utility's contribution to overall state electricity sales. Once all the megawatt targets in a particular incentive step were reserved via CSI applications, the incentive level offered by the CSI Program automatically dropped to the next lower incentive step. This created a demand-driven incentive program that adjusted solar incentive levels based on local solar market conditions.[94]

Second, the California Clean Vehicle Rebate Program (CVRP) began by providing relatively generous incentive payments (in the form of rebates) to encourage customer purchases of electric and other clean vehicles; over time, after the first 6 years of implementation, eligibility for rebates was capped at certain income levels and income-qualified purchasers could request a supplemental rebate, and total funding caps were established.[95] Incentives for the CVRP policy are funded, in effect, by the public: these rebates and program implementation are supported by the proceeds the California Air Resources Board collects from the sale of greenhouse gas emissions allowances.

Third, in an attempt to stimulate the market for power production based on alternative energy resources, California's early implementation of PURPA began with requirements that utilities purchase power from qualifying facilities (QFs) via a standard-offer contract based on the utility's administratively determined avoided cost. This proved to be relatively generous at the time, especially as the price of natural gas declined relative to the fuel price assumptions in the long-term avoided cost forecast. Other states adopted a similar approach early on. Eventually, as the market matured, many states capped the amount of power procured through such long-term contracts and turned to competitive solicitation processes as the means to determine price and other terms for the contracts. Evolution of PURPA contracting following a pattern of learning, with gradual movement toward greater efficiencies when the early, large subsidies were no longer needed (and were very expensive).

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94 https://www.cpuc.ca.gov/General.aspx?id=6058.

95 https://cleanvehiclerebate.org/sites/default/files/attachments/CVRP_Disruptions_Fact_Sheet.pdf.

Finally, a February 2021 report by the National Academies of Sciences, Engineering and Medicine Committee on the Future of Electric Power in the United States (of which I am a member) reached this conclusion and recommendation.[96]

> Policy makers and stakeholders should be ready to modify policies as conditions evolve, including through the use of sun-setting mechanisms in policy to phase them out over time. Often, such policies are adopted based on the expectation that there are barriers to entry of new technologies and that early entrants with a new technology and facing limited markets for their products will have relatively high costs. The policies are often designed to overcome these costs and then to allow growth in the market to push costs down. One practical reality of the adoption of such policy tools is that once they are in place—designed as they are to stimulate cost reductions over time—they are very hard to remove once the market is beginning to flourish. Those constituencies who benefit from the continued presence of such policies fight hard to retain them, even when market conditions improve for their products.... Establishing time limits or sunsets for certain market-conditioning policies is important as a way to avoid unintended consequences. Finding 3.13: More care is needed in the design of policies so that they can sunset or phase down over time when their original purposes have been met and economic, technological and social conditions change.

c) <u>Policy precedent and principles support NEM Reform in California now</u>

AB 327 sought to give the Commission the ability to "address current electricity rate inequities, protect income-qualified energy users and maintain robust incentives for renewable energy investments." Among other things, AB 327 mandates that successor NEM tariff(s) adopted by the Commission should meet several objectives and focuses the Commission's attention on ensuring: (1) sustainable growth in deployment of renewable generation on customers' premises, (2) access to opportunities for households in disadvantaged communities to adopt distributed generation resources, (3) the tariff will address participating customers' costs and benefits, and (4) the total benefits of the tariff to both the electric system and <u>all</u> customers are approximately equivalent to costs. This statutory directive to the Commission came in 2013, years after the launch of California's NEM program. It calls for the Commission to make changes to the subsidy program designed nearly two decades ago to

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[96] National Academies of Sciences, Engineering, and Medicine, "The Future of Electric Power in the United States," February 2021, page 139, https://doi.org/10.17226/25968.

"encourage private investment in renewable energy resources," "stimulate economic growth," and "enhance the continued diversification of California's energy resource mix." As explained in Chapter 1 of this testimony, California's NEM program has succeeded in accomplishing these objectives.

The guiding principles here are that however valuable the NEM 1.0 and 2.0 subsidies have been in supporting customer adoption of rooftop solar and the development of a solar market and industry in California—and surely they have been successful in doing that—such subsidies should be removed (i) now that the market has matured and the subsidies are no longer needed (e.g., because the cost of installed PV solar makes it increasingly affordable); (ii) because maintaining the subsidy would continue to provide unnecessary, costly, and unfair economic transfers from one group to another (e.g., from non-participants to participants); and (iii) because continuation of a subsidy would undermine and thwart the accomplishment of other public policy objectives (e.g., efficient pricing of electricity service; avoiding regressive outcomes associated with energy bills; pursuit of electrification goals for addressing climate change).

It is time to reform NEM 2.0 because:

- The payback periods are too rich for participating customers (*i.e.*, the current payback is 5-6 years,[97] yet the subsidy lasts for 20 years);
- The market for PV solar has taken off fabulously in California, which has the highest adoption of solar of any state in the country;
- This high level of deployment makes the subsidy too expensive for non-participating customers, many of whom already struggle to pay their bills;
- Utilities are purchasing power from NEM customers at a price much higher than what those utilities pay for supply (*i.e.*, avoided costs) from other sources of electricity (including other solar projects);
- The current NEM tariff is not competitively neutral from the perspective of customer need: The incentives are often higher for customers with higher incomes.
- The solar industry is neither fragile nor in a start-up mode: There is a large, multi-state market in the U.S. Installed PV costs are declining. There are numerous product offerings. Many solar companies are enjoying investor support. And many policies besides NEM 2.0 will continue to drive adoption of rooftop solar in California (and in other states).

These public-policy considerations support the need for significant reform of NEM 2.0 in addition to satisfying the statutory requirements to do so.

[97] Tesla promotes its solar product by saying that "[w]ith our new pricing, an average customer buying a large system in California will make their money back in only six years by reducing their electric bill, ultimately making an average of $88,000 over the system's lifetime." https://www.tesla.com/blog/lowest-price-home-solar.

d) Financial Support for Public Policy Objectives: Public funding sources, rather than utility customers, should pay for programs prioritized as important social/economic/programs by the California State Legislature

As described in more detail in Chapters 1 and 3, and above here in Chapter 2, some of the principal factors motivating the reform of the NEM 2.0 tariff include:[98] evidence that utilities pay more to NEM customers than they would pay to other suppliers for the same amount of energy and other electric grid benefits; the large subsidy provided to customers that adopt solar facilities by customers that don't; the fact that higher-income customers are more likely to install solar facilities; and the reality that low-income customers already bear a disproportionate energy-cost burden, even without taking into consideration the impact on their rates that results from having to pick up system costs not paid by NEM 1.0 and NEM 2.0 customers.

NEM reforms should not only lessen these economic burdens on low income-customers but also afford these customers better access to renewable energy.[99] In that regard, the Commission will be reviewing proposals from various parties to address the overall cost shift while still providing incentives for low- and moderate-income households' adoption of on-site solar installations. Both reflect critical fairness considerations, with the former squarely within the Commission's traditional ratemaking responsibilities (e.g., to allocate costs fairly and to do so according to cost-incurrence principles) and the latter aimed at broader policy goals for advancing social equity.

As the Commission evaluates the proposals from parties in this NEM successor tariff proceeding, an important consideration is whether these and other appropriate and valid public

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[98] *See, e.g.,*: Verdant Associates, "Net-Energy Metering Lookback Study," January 21, 2021, https://www.cpuc.ca.gov/General.aspx?id=6442463430; Bridget Sieren-Smith, Ankit Jain, Alireza Eshraghi, Simon Hurd, Julia Ende, and Josh Huneycutt, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates and Equity Issues Pursuant to P.U. Code Section 913.1," California Public Utilities Commission, February 2021 (hereafter "CPUC Staff 2021 White Paper on Electric Costs") https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Feb%202021%20Utility%20Costs%20and%20Affordability%20of%20the%20Grid%20of%20the%20Future.pdf.

[99] *See* also: Severin Borenstein, Meredith Fowlie, and James Salle, "Designing Electricity Rates for An Equitable Energy Transition," Next 10 publications, February 23, 2021 (hereafter "Borenstein et al. Rates Study"), https://www.next10.org/publications/electricity-rates.

policy goals should — and can — be supported directly through electricity rates rather than through some other funding sources.

To date, many of the state's policy goals are being effectuated through actions undertaken by the Joint Utilities, with consequences for the dollars that need to be recovered from electricity consumers in their utility bills. This approach has produced important outcomes to help the state transition its energy economy to a lower-carbon power system and with improvements in local air quality.

But the electricity rates of the state's major investor-owned utilities are relatively high (even if customers' electricity bills are closer to (and in some cases below) the national averages).[100] High electricity rates have a regressive effect on low-income households -- and more so than if some of these programs were funded through state income taxes and other public revenue sources.[101]

Where possible, reforms to the NEM program should explore other ways (besides subsidies paid for by non-participating customers) to provide financial incentives for Californians' adoption of rooftop solar. As explained by Matt Freedman of TURN:

> [T]he Commission should express a strong preference for identifying sources of funding other than rate revenues from all customers [in providing market transition credits ("MTCs") as part of a successor tariff]. The most suitable sources are state general fund monies including Cap-and-Trade funds (from the Greenhouse Gas Reduction Fund) that could be used to pay for some or all of the MTCs paid to participants. TURN's model allows for the availability of external state funds to be used to calculate the impact on the Rate Impact Measure (RIM) test results. Funding some or all of the MTC costs through sources other than retail rates would materially improve RIM test outcomes.

[100] CPUC Staff 2012 White Paper of Electric Costs.

[101] *See also*, CPUC Staff 2021 White Paper on Electric Costs, pages 28-29; Borenstein et al. Rates Study, pp.10, 43.

Although Mr. Freedman recognizes that the Commission cannot order the Legislature to appropriate money for this purpose,[102] the Commission can express a preference for external funding and adopt a mechanism that can accommodate external funding, should it become available over time. The Commission could also condition the expansion of the MTC to certain customer groups (such as non-CARE customers) on the availability of adequate funding from alternative sources.

There are several other reasons why the Commission should take this position. First, embedding financial subsidies for adoption of rooftop solar — and doing so without eliminating a cost shift — has the effect of increasing electricity rates and undermining the goal of electrification of buildings and vehicles. The staff of the CPUC made this same observation: "If handled incorrectly, California's policy goals could result in rate and bill increases that would make other policy goals more difficult to achieve and could result in overall energy bills becoming unaffordable for some Californians."[103]

Second, the Legislature is in a better institutional position to set priorities among various policy goals and harmonize the ways policies apply throughout the state. For example, using utility rates to implement policies introduces distortions in terms of signals to similarly situated customers who happen to be in the service territory of one utility with relatively high rates as opposed to living in the service territory of a utility with lower rates. As another example: using taxpayer-funded investments for the primary purpose of reducing carbon emissions in California's economy might lead to

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[102] The Joint Utilities' Income Qualified Discount and STORE proposals would embed subsidies in rates because of the uncertainty of securing funding from an external source. While this approach is not preferred for the policy and equity reasons highlighted in this section, the Joint Utilities felt that the equity concerns around solar and storage access are significant enough to propose subsidies embedded in rates on a transitional basis.

[103] CPUC Staff 2021 White Paper on Electric Costs, page 3. See also pages 6-7: "There is the potential for a growing divide in the cost of service between customers participating in behind-the-meter (BTM) or distributed energy resources (DER) and those who are less likely to do so. Moderate- to higher-income customers are more likely to invest in DERs such as solar photovoltaic (PV) systems, electric vehicles (EV), and storage technologies, and the advanced rate offerings that support them. This enables them to shift load and take advantage of potential structural billing benefits that follow, which often results in a cost shift toward the lower-income and otherwise vulnerable customers. Without the prudent management of IOU revenue requirements, rate base, rate structures, and DER incentives, California's continued progress toward the optimized grid of the future may widen this chasm between participants and non-participants."

a targeting of incentives toward the adoption of EVs (which avoid the combustion of fossil fuels) as opposed to rooftop solar (which may or may not avoid the combustion of fossil fuels, especially as the state's electric system becomes less carbon intensive over time.

In this proceeding, the Commission should focus first on reducing the cost shift and then condition the expansion of incentives to others beside income-qualified customers upon the availability of funds from sources besides utilities' electricity rates.

III.

EVALUATION OF NEM PARTICIPATION COST IMPACTS ON OTHER RETAIL ELECTRICITY CUSTOMERS

A. Introduction[104]

The current NEM tariff design and volumetric residential rates provide compensation for energy returned to the grid by distributed solar well above the avoided cost of such energy. This results in a $3.4 billion per year statewide cost shift from our NEM participants to the other customers we serve, including lower income customers who can least afford to pay for the subsidy. This substantial cost shift increases electricity rates for all customers, and particularly the electricity bills for non-participating customers. Aligning export compensation with the market value of rooftop solar and designing a tariff that recovers fixed infrastructure costs that solar customers incur to import and export energy is imperative to resolve the ongoing cost shift. Resolving the NEM cost shift is essential to help ensure California reaches its environmental goals in a manner that is equitable and affordable for all customers.

The purpose of this testimony is to present and explain the Joint Utilities' estimates of the current and projected cost shift from NEM 1.0 and 2.0 customers to non-participating customers and review how our proposed NEM Reform Tariff (DG-ST or Reform Tariff) scores on the California Public Utilities Commission's (Commission or CPUC) Standard Practice Manual (SPM) Tests for cost effectiveness. This testimony is organized as follows:

Section B. – Joint Utility NEM Cost Shift - highlights the causal factors of the cost shift, the impact on non-participating customers, many of whom are lower income customers, the calculation and

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[104] Chapter 3 builds upon the information provided in Chapter 1 and Chapter 2. In Chapter 1, witness Peterman discusses California's success in deploying customer-sited rooftop solar, the role of NEM and California other policies in delivering those outcomes, problems that now accompany and result from California's current NEM design, and the criteria the Commission should use in considering NEM proposals in this proceeding. Chapter 2 witness Tierney provides more policy context for the issues the Commission is considering here and describes NEM reforms that have been undertaken in other states, indications of the outlook for the solar and storage markets in and out of California, and key policy design principles the Commission should take into account in assessing the proposals for NEM reform.

estimated cost shift of the three utilities and discussion of other parties that have identified a growing and unsustainable cost shift from NEM 1.0 and NEM 2.0[105]

Section C. – Standard Practice Manual Tests - provides an overview of the CPUC Standard Practice Manual Tests and how these tests can be used to examine cost-effectiveness for distributed generation. As detailed below, our Reform Tariff proposal appropriately balances participant benefits against non-participant costs, ensuring equitable and sustainable growth for behind-the-meter generation and storage.

B. NEM Cost Shift Among Customers

1. NEM Cost Shift Overview and Mechanics

As noted in Chapter 1, PG&E, SDG&E, and SCE customers have installed significant volumes of rooftop solar to date, vastly exceeding the state's original program cap of 0.1% of utility peak load[106] and helping the state achieve near-term climate goals. However, the substantial increase in rooftop solar penetration has resulted in unintended consequences including a large, growing, and unsustainable cost shift to customers who cannot or do not want to install behind-the-meter generation.

A cost shift occurs when rates change for some customers because of the actions of another customer or groups of customers and may occur for a variety of reasons. At a high level and in the specific context of the NEM program, NEM creates costs shifts because the bill savings, or compensation, that NEM customers receive for their behind-the-meter generation exceeds the value that the solar generation provides to the system. In addition, the export compensation structure of NEM, coupled with the volumetric pricing structure of residential rates, allows NEM customers to avoid both fixed and variable costs incurred by the utility to serve them. Both the overcompensation for exported

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[105] The NEM program was established by Senate Bill (SB) 656 (Alquist), Stats. 1995, ch. 369, in 1995 codified in Public Utilities Code § 2827. From 1996 to the present, customers with eligible renewable generation facilities installed behind the customers' meters that meet certain technical requirements could choose to participate in a NEM tariff. The payment of net surplus compensation for exports to the grid by customer generators was authorized by AB 920 (Huffman), Stats. 2009, ch. 376, and implemented by the Commission in D.11-06-016. We refer to these early tariff arrangements as "NEM 1.0." Pursuant to AB 327 (Perea 2013), D.16-01-044 adjusted the NEM program and established a successor tariff, currently in effect and referred to as "NEM 2.0." To avoid confusion, it is useful to note that Commission issuances have referred to NEM 2.0 as the "successor tariff."

[106] Senate Bill 656.

excess generation and the costs that NEM customers avoid are recovered via higher electricity rates from non-participating customers, including lower-income customers.[107]

We calculate the statewide cost shift created by NEM 1.0 and NEM 2.0 at $3.4 billion per year and growing. Without substantial change being ordered by the Commission in this proceeding, this unsustainable cost shift is projected to grow to $10.7 billion per year by 2030. These calculated cost shifts have increased since the Joint Utilities' March 15 proposal primarily due to the avoided cost of rooftop solar provided by the revised draft results of the 2021 Avoided Cost Calculator, as well as current effective rates and solar adoption. The annual $3.4 billion cost shift from NEM 1.0 and 2.0 customers will inevitably grow as electric rates increase over the 20-year legacy period of these tariffs. Given the significance of the existing and projected NEM program cost shifts, it is imperative that the Commission limit additional customers from taking service on these tariffs.

Figure III-15 below presents the estimated cost shift through 2030 from NEM 1.0 and 2.0 customers, assuming the CPUC were to take no action to resolve this cost shift. It is important to highlight that this projected cost shift does not end in 2030 due to the 20-year legacy period associated with NEM 1.0 and NEM 2.0. Customers interconnecting systems today will continue to receive subsidies into 2041, well beyond the current payback periods observed by each of the utilities. The calculated payback periods under NEM 2.0 of each utility can be seen in Table IV-14 of Chapter 4 of this testimony.

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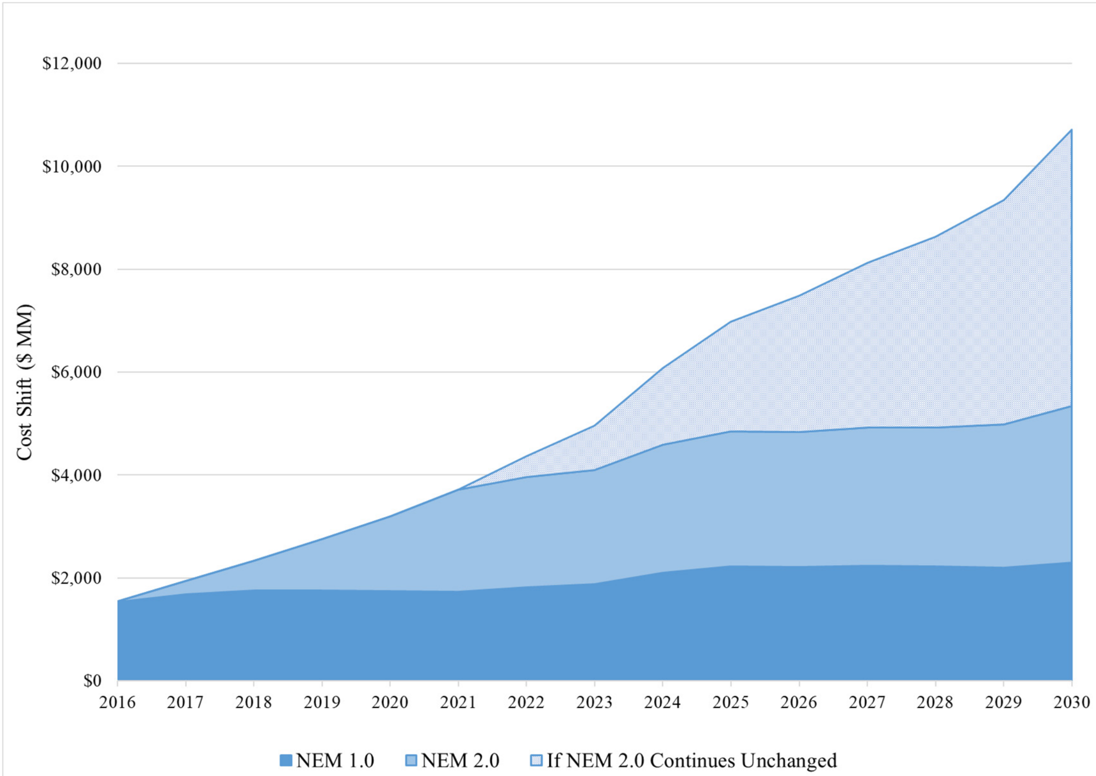
[107] California Public Utility Commission's report, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues pursuant to P.U. Code Section 913.1" February 2021, page 27-28.

Figure III-15
Annual Statewide NEM Cost Shift



The NEM cost shift is largely driven by residential NEM customers primarily due to the amount of MW installed by this customer class. As illustrated in Table III-7, the residential class represents ~65% of the installed rooftop solar capacity in the Joint Utilities service territories. The cost shift from residential customers is further exacerbated due to residential rate design in California that predominantly recovers both fixed and variable costs through volumetric per-kWh rates, which is discussed later in this testimony.

Table III-7
Installed Capacity of Residential and NonResidential Customers[108]

NEM Customers	MW of Installed Rooftop Solar	% of Total
Residential	6,459	65%
Non-Residential	3,461	35%
Total	9,920	100%

The cost shift from participating to non-participating customers is the result of two key components of the NEM tariff design:

1. *Non-participating customers overcompensate NEM customers for their exports*. Export compensation is tied to retail electricity rates, meaning NEM customers are overcompensated for the value their resource provides to the grid – a situation that will worsen due to anticipated future increases in retail rates over time; and

2. *Non-participating customers pay for the infrastructure and public policy costs that NEM customers avoid*. Residential NEM customers can bypass payment of infrastructure and other costs incurred to serve them, because such costs are embedded in volumetric rates, avoided by NEM customers, requiring other customers to make up the difference.

2. Overcompensating Exports

NEM customers are compensated at or near the full retail rate for exported generation (for NEM 1.0 and NEM 2.0 customers, respectively).[109] These retail rates include substantially more components than just the value of the energy: customer costs, distribution costs, transmission costs, and

[108] As of May 2021.

[109] NEM 1.0 customers are compensated at full retail rates; NEM 2.0 customers pay non-bypassable charges (NBCs) on energy delivered to the customer during each metered interval.

the costs of legislative and regulatory mandated public policy programs are all included in a residential customer's volumetric energy rate.

The difference between actual value and current compensation for exported NEM generation is striking. Statewide, the export compensation NEM customers receive is 8 times the price we could procure the same power for in the market.[110]

3. Avoiding Infrastructure and Policy Costs

After installing a solar system, NEM customers are able to reduce the volume of electric deliveries that they pay for by either (1) directly serving a portion of their load with on-site generation or (2) netting exported generation against the amount of imported energy over a twelve-month period. This creates a fairness issue because residential costs, both fixed and variable, are primarily recovered through volumetric rates. This means that customers can avoid paying fixed costs without proportionately reducing fixed cost spending by the utility. Fixed costs (e.g., grid infrastructure) policy costs (e.g., funding the California Alternate Rates for Energy (CARE) program) and distribution costs (e.g., wildfire mitigation) are examples of costs that are billed on a per kilowatt-hour (kWh) basis for residential customers and which can therefore be – and are – unfairly avoided by NEM customers.[111]

The CARE program is a state policy priority in which costs are intended to be recovered from all other customers, both residential and non-residential. Moreover, wildfire mitigation and grid infrastructure upgrades are activities that benefit all customers, including NEM customers who rely upon and use the distribution system just as much as non-NEM customers, given that they rely on the distribution system to deliver energy services to the customer as well as to receive exported energy.

As noted previously, someone must pay for the overcompensation of NEM exports and the costs that NEM customers avoid paying. The costs avoided by NEM customers are inequitably shifted and recovered from non-NEM customers (*i.e.*, cost shift). Allowing such a sizable – and growing – portion of our customers to avoid paying these costs and requiring a shrinking pool of

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[110] 2019 Average Utility Scale Solar CAISO PPA price from the Lawrence Berkley National Laboratory Utility-Scale Solar Data Update: 2020 Edition and current residential class average rates of the three IOUs.

[111] NEM 2.0 customers pay non-bypassable charges for kWh imported from the grid, but still avoid paying for policy costs through onsite consumption.

remaining customers to shoulder these costs is not sustainable. The Commission can and must resolve this growing inequity by adopting a reform tariff to the current NEM tariff that ensures equal collection of unavoidable and non-bypassable charges from all retail customers – both Reform Tariff participants and non-participants – and require all consumers to pay a fair share for the grid services they use.[112]

4. <u>Non-Participant Impacts</u>

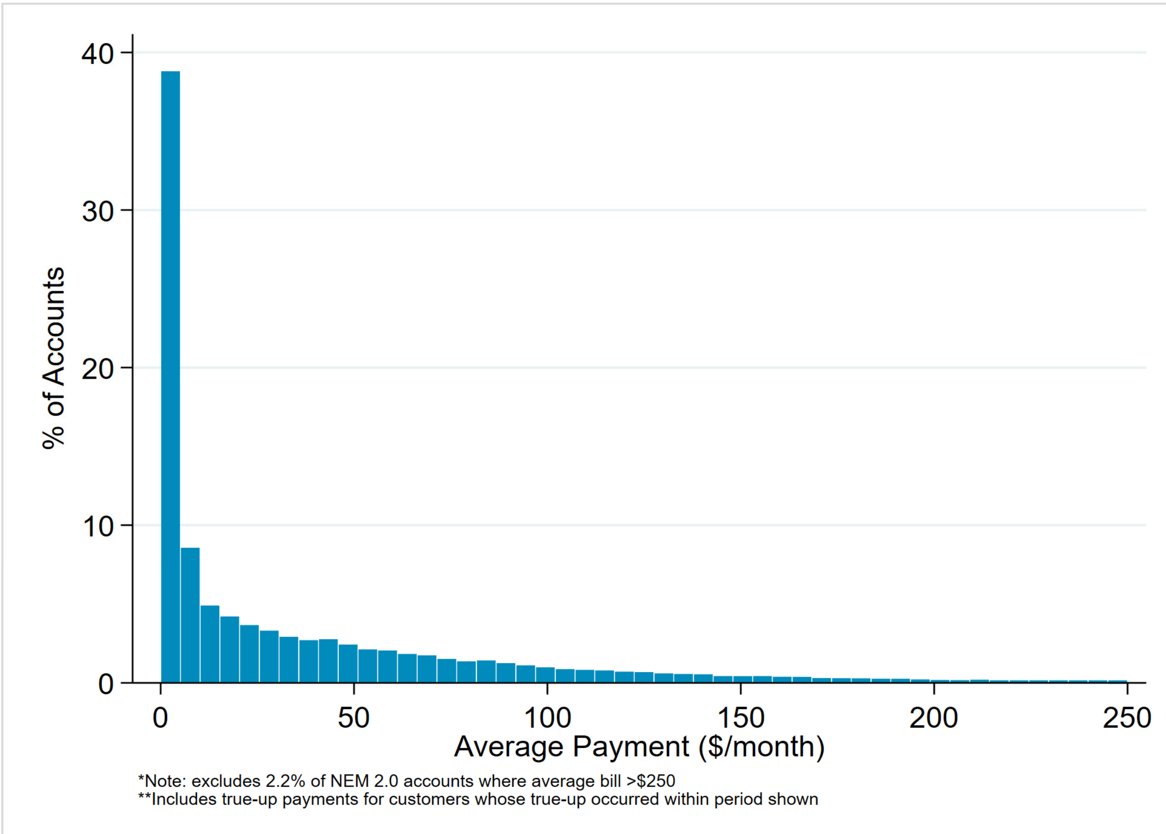
a) <u>Cost Shift Increases Bills of Non-Participating Customers</u>

The Commission's NEM 2.0 Lookback Study concluded that NEM 2.0, like NEM 1.0 before it, increases rates for electric customers.[113] While electric rates increase because of the NEM tariffs, non-NEM customers experience the greatest impact. As electricity rates increase, the subsidy paid to NEM customers also increases, diminishing the bill impact for adopting customers. Figure III-16 below provides a snapshot of SDG&E's NEM 2.0 residential customers' average monthly payments from April 2020 – March 2021.

[112] D.21-02-007, Guiding Principle B. The Commission has adopted eight Guiding Principles for the development of a successor to the current NEM tariff.

[113] Verdant Associates, "Net-Energy Metering 2.0 Lookback Study," Submitted to the California Public Utilities Commission Energy Division, January 21, 2021, pp. 12-13.

Figure III-16
Residential NEM 2.0 Average Monthly Payments SDG&E
April 2020 – March 2021



As highlighted in Figure III-16, "Residential NEM 2.0 Average Monthly Payments," above, a significant portion of NEM 2.0 customers make minimal payments each month. On the other hand, non-participating customers, many of whom cannot or choose not to install rooftop solar, pay higher bills due to the NEM programs. We calculate that the current $3.4 billion cost shift equates to a ~$245 per year increase on an average customer's electricity bill in SDG&E's service territory where rooftop solar penetration is the highest among the Joint Utilities. If no change is made, this annual bill impact is calculated to be ~$555 per year by 2030 in SDG&E's service territory for the average non-participating customer. Table III-8 below highlights the calculated average bill impacts for each utility.

Table III-8
Calculated Annual Bill Increase Associated with NEM Cost Shift for Non-Participating Non-CARE Customers

Utility	Non-CARE Customer 2021	Non-CARE Customer 2030
PG&E	$ 170 / year	$ 505 / year
SDG&E	$ 245 / year	$ 555 / year
SCE	$ 115 / year	$ 385 / year

b) <u>Inequitable Impacts – Low-Income Non-Participants are Negatively Impacted</u>

In addition to understanding that the NEM program shifts costs from participating to non-participating customers, it also is imperative to understand which customers are benefiting most from this tariff and which customers are being hurt the most by the NEM cost shift. As discussed in Chapter 2, NEM tariffs in California are an example of a subsidy where one group of customers provides a financial transfer to another. Specifically, NEM is a financial transfer from non-participating customers who are generally younger, lower-income, and more disadvantaged relative to NEM customers. The Lookback Study results were summarized in the CPUC's February 2021 report on rates and affordability and highlighted that NEM customers are disproportionately older, live in high-income areas, are more likely to own their home, and are less likely to live in a disadvantaged community.[114] While the trend of lower income adoption has improved in recent years, adoption still trends towards wealthier households. Lawrence Berkeley National Laboratory (LBNL) found that the median income of 2019 California solar adopters were above the state's median household income.[115] Looking specifically at the Utilities, residential NEM customers are disproportionately non-CARE customers.

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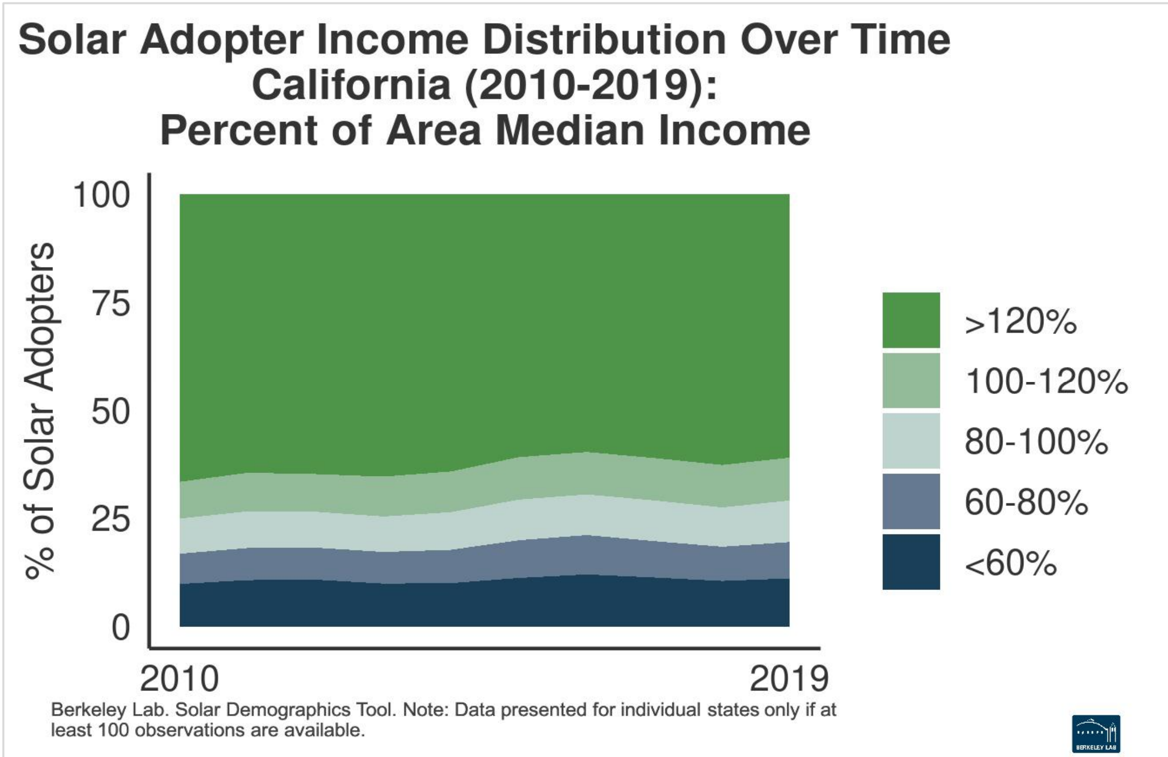
[114] California Public Utilities Commission's report, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues pursuant to P.U. Code Section 913.1" February 2021, page 28.

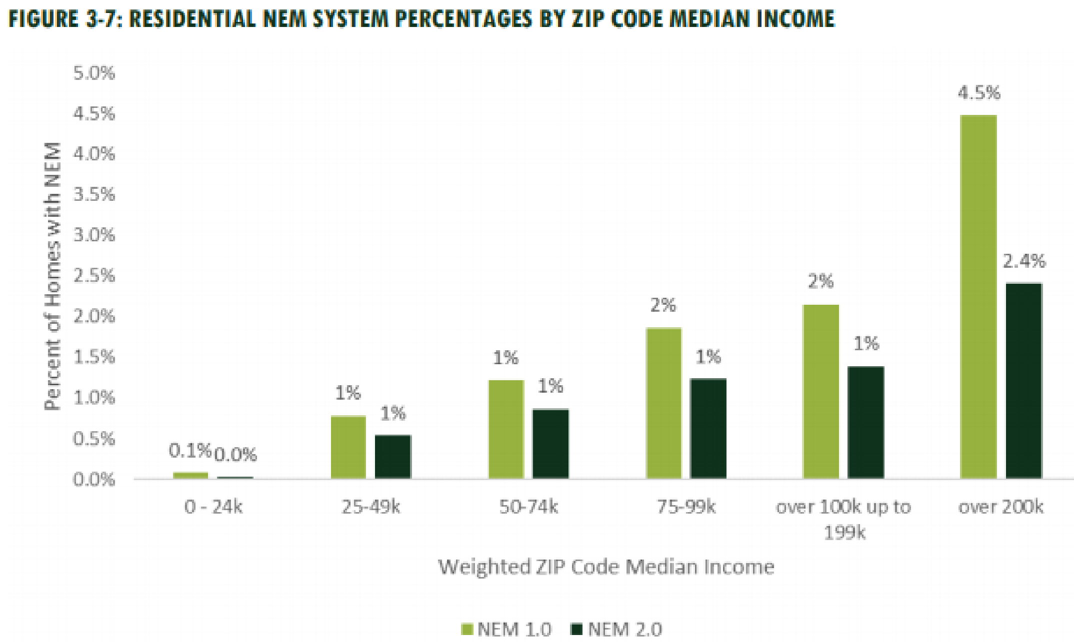
[115] Lawrence Berkeley National Laboratory "Residential Solar-Adopter Income and Demographic Trends: 2021 Update" April 2021 slide 14.

Figure III-17
Solar Adopter Income Distribution Over Time California (2010-2019): Percent of Area Median Income



Source: Lawrence Berkeley National Laboratory "Residential Solar-Adopter Income and Demographic Trends: 2021 Update" April 2021 slide 14.

Figure III-18
Residential NEM System Percentages by Zip Code Median Income



Source: NEM 2.0 Lookback Study

Thus, the NEM cost shift creates a heavy burden on lower income customers who already face energy affordability challenges as highlighted in Chapter 2 of this testimony. We calculate that the current $3.4 billion cost shift equates to an approximate $150 per year increase to a CARE customer's average electricity bill in SDG&E's service territory where rooftop solar penetrations is the highest among the Joint Utilities. This equates to CARE customers paying on average over 17% more per year on electricity in SDG&E's service territory. If no change is made, the annual average bill impact for CARE customers will continue to increase to $345 for the average CARE customer in SDG&E's service territory in 2030. Table III-9 below highlights the calculated average bill impacts to CARE customers for each utility.

Table III-9
Calculated Annual Bill Increase Associated with NEM Cost-Shift for Non-Particpating CARE Customers

Utility	CARE Customer 2021	CARE Customer 2030
PG&E	$ 95 / year	$ 285 / year
SDG&E	$ 150 / year	$ 345 / year
SCE	$ 75 / year	$ 255 / year

c) <u>Inequitable Impacts – NEM Subsidy is Significantly Larger than the CARE Subsidy</u>

As discussed above, the NEM 1.0 and NEM 2.0 subsidies generally provide benefits to customers that are older, wealthier, more likely to be homeowners and less likely to live in disadvantaged communities.[116] Not only are the subsidies provided to more advantaged customers, but they are also significantly larger than those provided to our income-qualified customers to assist them with their electricity bills. The table below highlights the current NEM cost shift is now over 2.4 times the amount of the annual electric CARE subsidy provided to income-qualified customers. In SDG&E's service territory, the NEM cost shift is now nearly 5 times the amount of the annual electric CARE subsidy provided to customers. Even worse, while the NEM cost shift is multiples above the CARE subsidy, the number of customers in need of assistance through the CARE program is significantly higher than the number of NEM customers. This extreme misalignment is another example that compensation to rooftop solar customers is in desperate need of reform.

[116] California Public Utility Commission's report, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues pursuant to P.U. Code Section 913.1" February 2021, page 28.

Table III-10
Comparison of NEM and CARE Programs

	NEM	CARE	NEM Relative to CARE
Total Annual Subsidy ($ in billions)	$3.4	$1.4	2.4x amount of subsidy
Total Benefitting Customers	1,119,000	2,828,000	0.4x benefiting customers

d) <u>NEM Creates Affordability Issues for Non-participating Customers</u>

The current NEM programs have been determined to increase electricity rates as illustrated by the Ratepayer Impact Measure.[117] This leads to higher energy costs for all our customers, but the most significant bill impacts can generally be higher for those customers with higher energy needs, including those customers who rely on electricity to heat or cool their home during extreme weather events. This also creates additional challenges for the state as it looks to increase electrification to help meet its climate goals. Higher electricity rates for non-participating customers create affordability challenges both for necessary use and additional use associated with electrification. This has the potential to stunt the adoption of electrification technologies or limit adoption to only those who can afford the increase in electricity costs, exacerbating affordability challenges for lower income customers.

5. <u>Joint Utility NEM Cost Shift Methodology</u>

To provide a comprehensive overview of the NEM cost shift, we developed a uniform cost-shift analysis model ("cost shift model"). The cost shift model is an Excel-based spreadsheet model that produces annual cost shift values for NEM 1.0 and NEM 2.0. The cost shift model uses publicly available data, where available, to increase transparency and understandability for all stakeholders.

[117] The Ratepayer Impact Measure (RIM) is discussed further in Section III.C.

The NEM cost shift is defined as:

NEM COST SHIFT *= Total NEM Customer Bill Savings – Avoided Costs*

Where: Total NEM Customer Bill Savings = (Annual Production[118] ** Average NEM Customer Retail Rate) – (Annual Production * Export Percentage*[119] ** Non-bypassable Charges (NEM 2.0 only))*

Avoided Costs = CPUC 2021 ACC Hourly Profile[120] ** PVWatts® Solar Production Load Hourly Profile*

The estimate of total NEM customer bill savings captures both total compensation for exports and avoided infrastructure and policy costs due to onsite usage and netting described above. These two elements create substantial financial benefits of the program to participants. Forward-looking cost shift estimates assume rates increase 4% per year and utilize the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) forecast of installed PV capacity.[121]

To calculate avoided costs or "value," the cost shift model uses the Commission's most recently proposed version of the Avoided Cost Calculator (ACC).[122] Multiplying these ACC values by the National Renewable Energy Laboratory's (NREL) PVWatts® production profile, which estimates the energy production of grid-connected photovoltaic (PV) energy systems,[123] allows us to determine an approximation of the value provided by customer-sited generation in the utilities' service territories.

[118] NEM installed capacity kw-AC * 8760 * average generation capacity factor. Capacity factor from: Verdant Associates, "Net-Energy Metering 2.0 Lookback Study," Submitted to the California Public Utilities Commission Energy Division, January 21, 2021.

[119] Class average export percentages by utility using historical data.

[120] For years prior to 2020, the Joint IOU cost shift model uses 2020 avoided cost values to provide backward looking cost shift analyses.

[121] The Utilities use the IEPR's Mid-Demand Scenario PV forecast.

[122] The ACC is a tool developed by the CPUC to produce an "hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours" and includes values for six components: energy, capacity, greenhouse gas reduction, reduced methane leakage, transmission and distribution. We use this value because it is a convenient administratively determined proxy for the cost of generation on the margin that is "avoided" by NEM exports, and, as further described herein, has been used in a variety of Commission proceedings to assess the cost-effectiveness of distributed generation. Per ALJ Hymes' May 21, 2021 ruling, for purposes of calculating the cost shift in this testimony, the Joint Utilities use the ACC proposed in draft resolution E-5150, published May 3, 2021.

[123] https://pvwatts.nrel.gov/.

a) **Specific Utility NEM Cost Shifts**

Figure III-19
PG&E Current and Projected NEM Cost Shift
(Millions per Year)

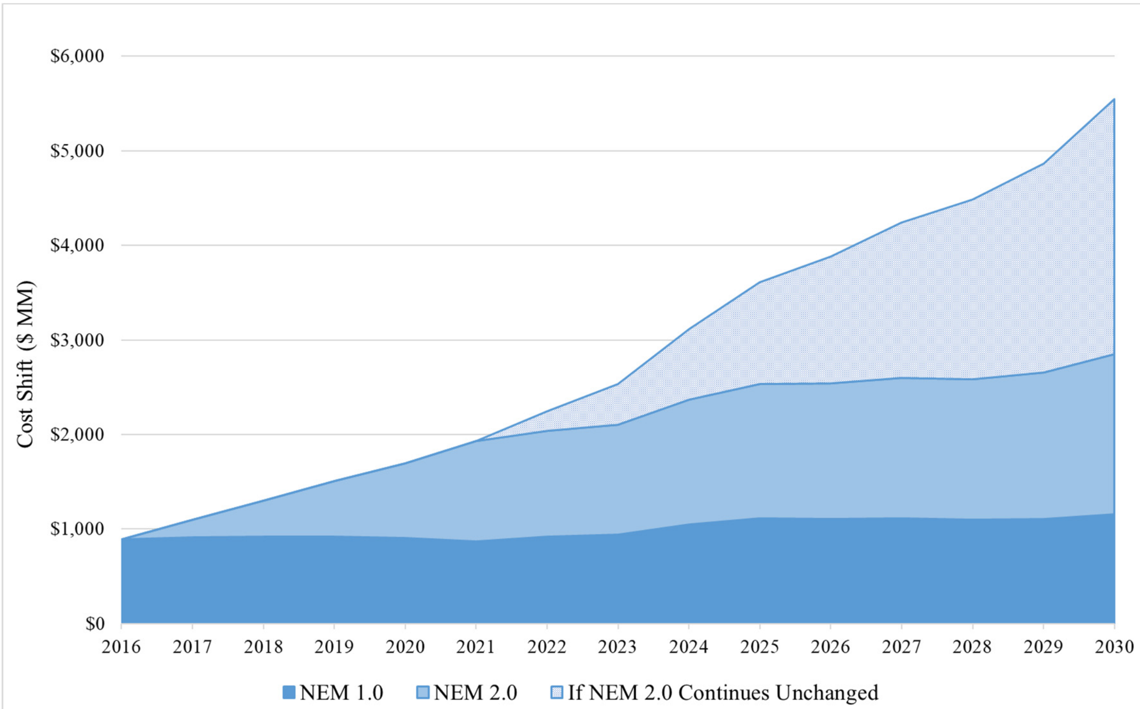


Figure III-20
SDG&E Current and Projected NEM Cost Shift
(Millions per Year)

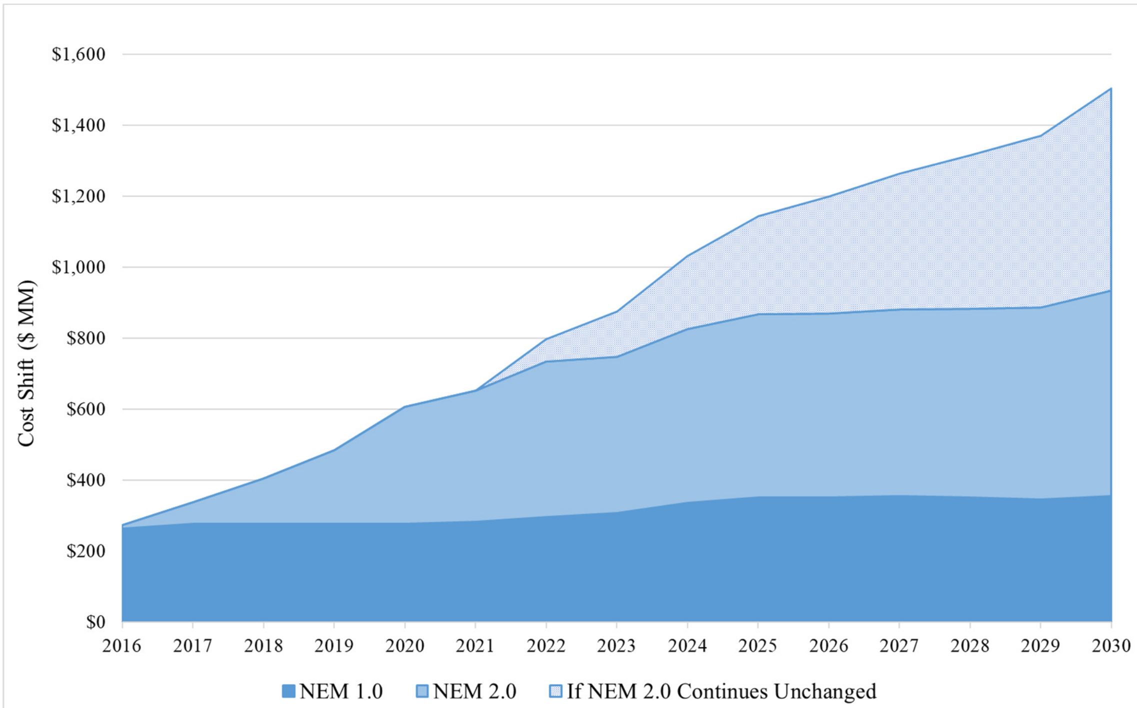
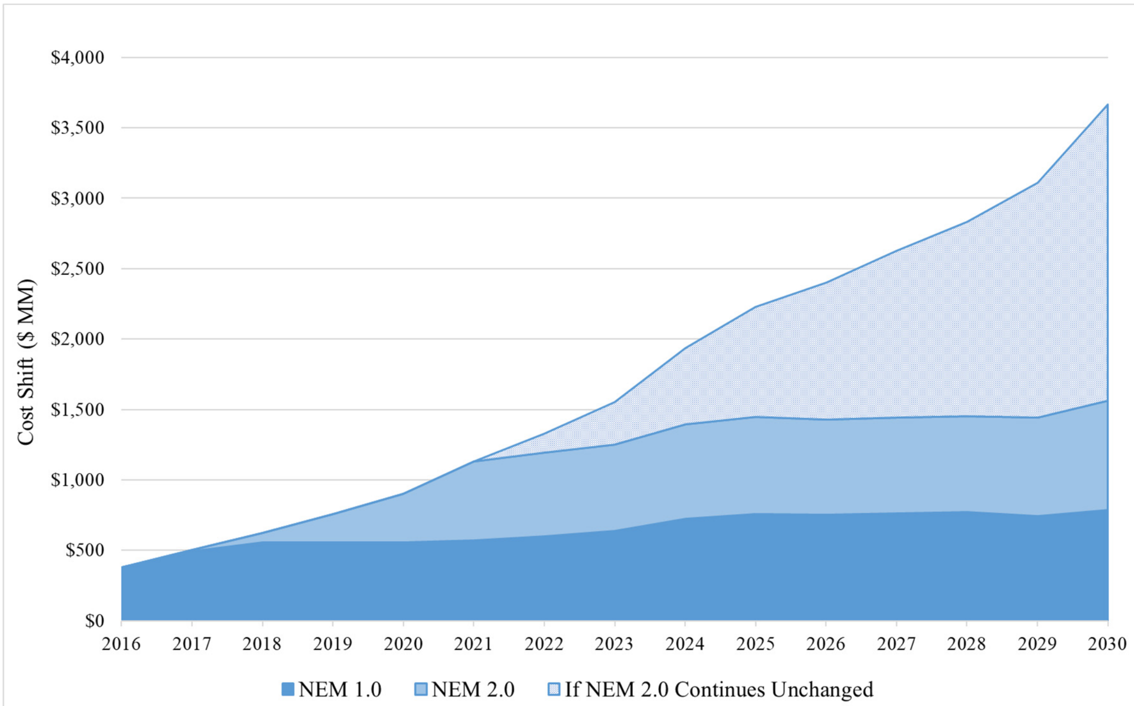


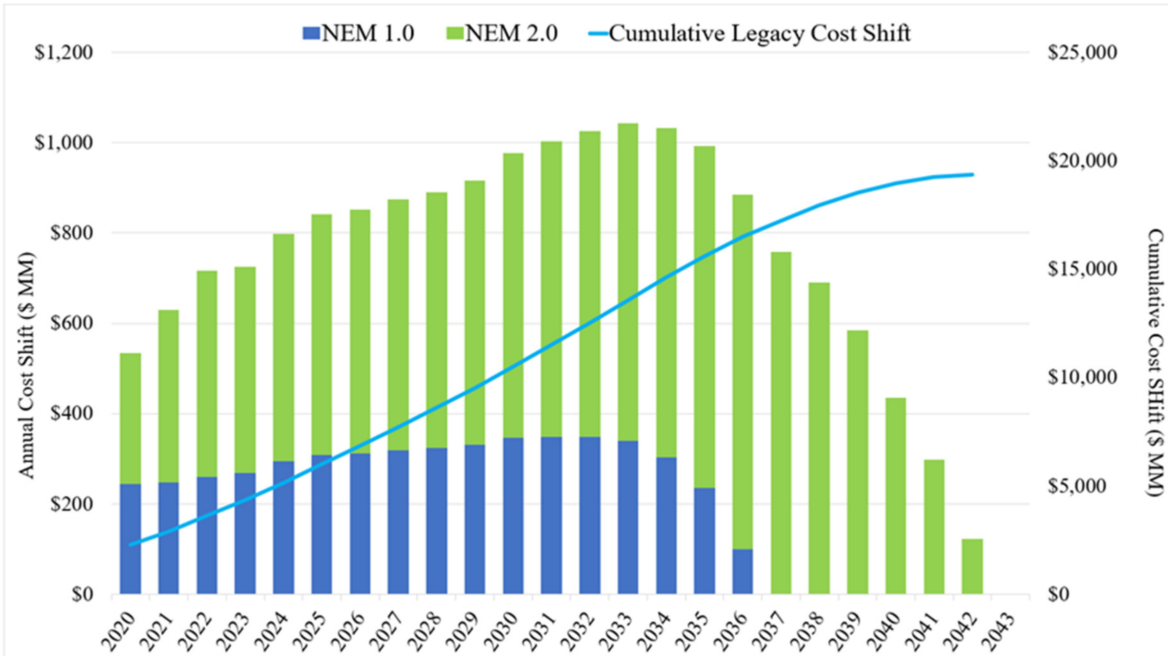
Figure III-21
SCE Current and Projected NEM Cost Shift
(Millions per Year)



b) **<u>Current 20-Year Legacy Period Extends the Cost Shift Well into the Future</u>**

Per the current NEM tariffs, customers interconnecting systems today will receive subsidies for the next 20 years. To put this into context, a new customer interconnecting a rooftop solar system under the current NEM tariff in 2022 will receive subsidies, and shift costs to non-participants, into 2042. Most customers who purchase their system will achieve a system payback well before the end of that 20-year period. Figure III-22 below provides a 20-year look at the annual and cumulative calculated cost shift for SDG&E's current NEM 1.0 and 2.0 residential customers and projected new customers through 2022, assuming NEM 2.0 eligibility ends on December 31, 2022. Given the significance of the existing and projected NEM program cost shifts, the Commission must limit additional customers from taking service on these tariffs here and now.

Figure III-22
SDG&E Residential NEM 1.0 and 2.0 Cost Shift Forecast
of 20-Year Legacy Period



c) **Drivers of Future Cost Shift**

We have used reasonable assumptions to estimate the NEM cost shift. However, there are factors that can increase the calculated cost shift in the future. For example, the current NEM structure provides credits that are tied to the retail rate, resulting in an increased subsidy as residential rates increase. This generous and growing NEM subsidy is no longer needed to incentivize adoption as solar technology costs continue to plummet and other policies provide additional support to solar.[124] Chapter 2 provides policy reasons for sunsetting the NEM subsidy. Current cost shift calculations assume rates grow at 4%. Recovering required and authorized investments through a shrinking sales volume will continue to put upward pressure on volumetric rates and potentially create rate increases greater than the current assumption. In addition, customer adoption above the current CEC's IEPR forecast used to develop the projected cost shift can also lead to an increased calculated NEM cost shift

[124] National Renewable Energy Laboratory, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, January 2021.

in the future. We urge the commission to take immediate action to reform NEM in California to limit further increases in the NEM cost shift.

6. Other Parties' Cost Shift Analyses

Other parties have highlighted that the current NEM tariffs create a cost-shift between participating and non-participating customers. While inputs and methodologies can vary from analysis to analysis, the overall trend has shown that the cost shift from current NEM customers is significant and unsustainable. Relevant analyses include the following:

a) E3's Cost Shift Analyses

(1) E3 White Paper Dated January 28, 2021

In its white paper developed for the CPUC as part of this proceeding, E3 highlights how a cost shift is created by the NEM tariff.[125] E3 describes that the NEM tariffs allow NEM customers to benefit from being compensated at inflated volumetric electricity rates. These volumetric rates include fixed cost recovery and are substantially higher than the marginal cost of energy. E3 also highlights that rooftop solar maximum output does not coincide with system peak demand, weakening the argument for an inflated compensation structure for this resource. In the white paper, E3 states, "…substantial misalignment between costs and value under the current compensation structure. This results in an increase in costs to be recovered from nonparticipating customers."[126]

(2) E3 Comparative Analysis Dated May 28, 2021

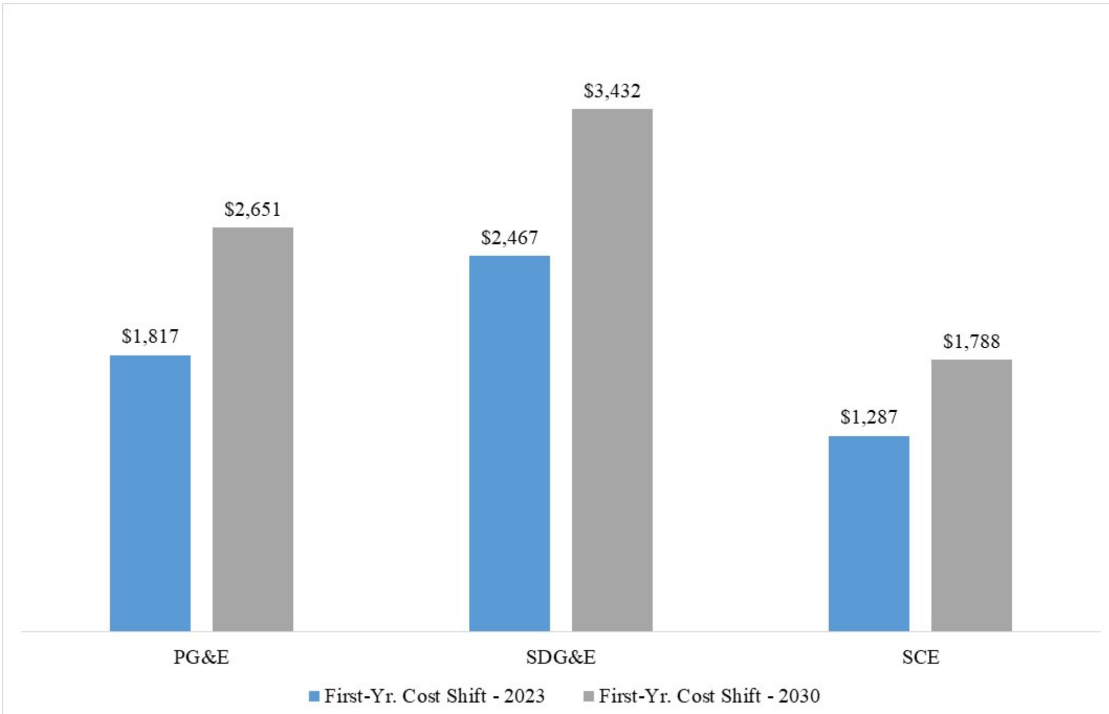
E3 completed a comparative analysis of various proposals in this docket as well as the impact of the current NEM 2.0 to serve as a guide for the CPUC and parties in this proceeding. As part of that analysis, E3 calculated the first-year cost shift for each proposal as well as NEM 2.0 using standardized assumptions. The first-year cost shift is defined in the analysis as the dollar value of utility costs shifted from participants to nonparticipants in the first year after

[125] The Commission engaged Energy and Environmental Economics, Inc. (E3) to support and facilitate the development of proposals for a reformed NEM tariff in this proceeding that will comply with California legislation, including Assembly Bill 327.

[126] E3 report titled "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California; Successor Tariff Options Complaint with AB 327" January 28, 2021 Page 14.

interconnection. Figure III-23 below highlights E3's calculated first year cost shift to non-participating customers in years 2023 and in 2030.

Figure III-23
E3 NEM Cost Shift Per Customer
Non-CARE, Solar Only First-Year Cost Shift



Source: E3's "Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020 – A Comparative Analysis". May 28, 2021. Pages 34 and 38.

b) <u>Verdant NEM 2.0 Lookback Study</u>

In January 2021 Verdant Associates completed a study on the costs and benefits of NEM 2.0 on behalf of the CPUC. This study found that NEM 2.0 solar installed through 2019 would cause a net present value of $13 billion in cost shifts over their lifetime.[127]

[127] Translated to an annual impact, this would be over $1 Billion in cost shifting per year, consistent with our estimate for NEM 2.0 installations of the same vintage. NEM 2.0 Lookback Study, p. 79

The results of the study were also summarized in the CPUC's February 2021 report on rates and affordability and point to a cost shift between participating and non-participating customers highlighting:[128]

- NEM 2.0 is not an effective tariff on a system level illustrated by the results of the CPUC's Total Resource Test.
- NEM customers are overcompensated relative to value of the energy and grid benefits produced.
- NEM 2.0 shifts costs to non-participating customers and leads to increases in non-participating customers' bills highlighted by the CPUC's Rate Impact Measure test.
- NEM subsidies are "disproportionately paid by younger, less wealthy, and more disadvantaged ratepayers, many of whom are renters".

c) **California Public Advocates Office (Cal Advocates)**

In its proposal submitted in March 2021, Cal Advocates highlights that there is misalignment between the compensation NEM customers receive relative to the value of energy generated. For example, Cal Advocates points out that, for SDG&E, the California utility with the highest penetration of rooftop solar in its service territory, the average NEM 1.0 customer compensation in 2020 was nearly seven times the value of the energy generated. Across the three utilities, Cal Advocates concludes that the annual cost burden generated by NEM 1.0 and NEM 2.0 and paid for by non-participating customers is $2.85 billion (in 2021 dollars).[129] The Cal Advocates cost shift methodology parallels our analysis, although the Cal Advocates analysis looks at the ACC on a 10-year levelized avoided cost of solar generation versus our approach of using one-year levelized ACC values. Cal Advocates' cost shift calculation produces a similar cost shift result to our model. Our current cost

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[128] California Public Utility Commission's report, "Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues pursuant to P.U. Code Section 913.1" February 2021, pages 27-29.

[129] Public Advocates Office Amended Proposal for a Successor Tariff to the Current Net Energy Metering Tariffs March 15, 2021.

shift calculation is slightly higher due to using recently updated retail rates and updated ACC values from the draft 2021 ACC.

d) Next 10 and the Energy Institute at UC Berkeley's Haas School of Business

Next 10 and the Energy Institute at UC Berkeley's Haas School of Business recently co-authored a paper titled "Designing Electricity Rates for An Equitable Energy Transition" that examines how Californians pay for electricity. In that paper, the authors highlight that behind the meter solar shifts the burden of fixed cost recovery onto customers that have not adopted rooftop solar systems. The paper highlights residential customers with PV systems are generally credited at the retail electricity rate for every kWh of solar electricity they generate. This produces a generous subsidy because residential rates significantly exceed social marginal cost and include fixed cost recovery. The growing gap between the retail rate and marginal cost reflects costs that are not avoided by NEM customers but rather shifted to non-participating customers when a household adopts rooftop solar. Although the paper does not estimate a total statewide cost shift, it does estimate the average significant annual bill impact for non-participating customers.[130]

C. Evaluation of the proposed Reform Tariff under Standard Practice Manual

1. Introduction

The following testimony provides a brief overview of the purpose and intent of the CPUC's Standard Practice Manual (SPM), how the SPM framework is implemented for distributed generation (DG) technologies, how the SPM tests can be used in assessing NEM successor proposals, and the Utilities' estimation of each of the relevant tests for our proposed Reform Tariff. Key to this section will be a discussion of the different perspectives each SPM test takes, and how each should be used in evaluating demand side programs. This section will also go into detail on some of the key inputs into these cost-effectiveness tests, including the CPUC's calculation of avoided utility costs in the Avoided Cost Calculator (ACC).

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[130] Next 10 and Energy Institute at Haas, UC Berkeley paper titled "Designing Electricity Rates for an Equitable Energy Transition". The paper highlights the largest impacts are seen in SDG&E's service territory and are calculated to be ~$230 per year for non-CARE customers and over $120 per year for CARE customers. https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf

2. Overview of SPM Tests, Strengths and Weaknesses, and Ties to DG Cost-Effectiveness

The Commission's Standard Practice Manual establishes a universal cost-effectiveness analysis framework for evaluating the costs and benefits of demand side management programs and technologies, including energy efficiency, conservation, load management, load building, fuel substitution and self-generation.[131] The framework outlines four tests, representing the perspectives of groups impacted by the demand side program: 1) participants, 2) non-participants, 3) all ratepayers, and 4) the utility (or program administrator).[132] Importantly, the SPM notes that these tests are not intended to be used individually or in isolation because each test has relative strengths and weaknesses and these tradeoffs must be considered when assessing demand side policy.[133] The relevant tests[134] and their relative strengths and weaknesses are described below.

- The **Participant Cost Test (PCT)** measures the quantifiable benefits and costs to the customer due to participation in a program, compares the out-of-pocket costs to a participating customer with the benefit received by the customer, including reduction in the customer's utility bill, any incentive paid to the customer by the utility or other third parties, and any tax credit received. A PCT benefit-cost ratio above one indicates that the program is beneficial to participating customers, meaning the present value of the financial benefits realized through bill savings, incentives, and tax credits exceed the out-of-pocket costs.

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[131] The most recent version of the Standard Practice Manual (SPM) can be found at: https://www.cpuc.ca.gov/general.aspx?id=5267.

[132] SPM, p. 1. The SPM also discusses a societal perspective as a variant of the TRC, also known as the Societal Cost Test (SCT). This captures costs and benefits beyond the utility, participants and other ratepayers who fund and enable the program. To date, this test has not been approved for use in demand-side proceedings, therefore it is excluded from in depth discussion below.

[133] SPM, p. 6.

[134] Besides the TRC, PCT, and RIM tests described below, the SPM also includes a Program Administrator Cost (PAC) test that measures the benefits and costs to the Program Administrator. In addition to excluding the costs incurred by participating customers, the PAC test, like the TRC, treats bill savings and incentive payments as a transfer payment. The PAC test thus has limited value in evaluating the design of a specific program or tariff and has been excluded from the discussion in this testimony.

- **Strengths**: Reflects the desirability of the program to adopting or potential adopting customers. Helpful in determining potential participation rates, program incentive design, and developing participation goals.
- **Weaknesses**: Cannot capture all elements of customer decision-making, such as consumer attitudes and behavior.[135]

- The **Ratepayer Impact Measure (RIM)** test measures what happens to customer rates due to changes in utility revenues and operating costs caused by the program. Compares the utility's costs, incentives paid to the participant, and decreased customer revenues attributable to the program with the avoided supply cost "benefit," including the relevant avoided transmission, distribution, generation, and capacity costs. A RIM benefit-cost ratio above one indicates that the program is likely to result in lower rates.
  - **Strengths**: Only test that evaluates the distributional and equity impacts of programs by reflecting revenue shifts between customers.
  - **Weaknesses**: Sensitive to assumptions of long-term marginal (avoided) utility costs and rates.[136]
- The **Total Resource Cost (TRC)** test compares the net costs of the program as a resource option, including both the participants' and the utility's costs, with the same avoided supply costs used in the RIM. A benefit-cost ratio above one indicates that the program is beneficial on a total resource cost basis, *i.e.*, beneficial to those investing in the program (utilities and its ratepayers), as well as the program participants.
  - **Strengths**: Evaluates the costs and benefits of a given measure for providing energy services to California from a broad perspective.

[135] SPM, pp. 9-10.

[136] SPM, pp. 14-15.

- **Weaknesses**: Because the test treats any bill savings and incentive payments as transfer payments, it can be of limited value in evaluating the design of a specific program or tariff.[137]

The SPM at a high level outlines how benefits and costs should be considered from each of the perspectives, but notes that the implementing agency has discretion to set policy rules around how each test should be implemented.[138] For distributed generation (DG) technologies, this policy was formalized in D.09-08-026, including the categories of benefits and costs to use, and the values and/or data sources for each category.[139] Table III-11 is based on Attachment A to D.09-08-026, and summarizes the relevant NEM benefits and costs and how they are considered from each perspective:

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[137] SPM, pp. 20-21. Energy efficiency programs do include incentive payments to program free-riders in the TRC, but this has not been applied to other programs.

[138] SPM, p. 7.

[139] D.09-08-026, p. 20 and Attachment A.

Table III-11
Summary of DG Benefit and Cost Categories by SPM Test[140]

	Participant Cost Test (PCT)		Ratepayer Impact Measure (RIM) Test		Total Resource Cost (TRC) Test	
Category	**Benefit**	**Cost**	**Benefit**	**Cost**	**Benefit**	**Cost**
Avoided Costs			X		X	
Bill Savings (Reduced Revenues)	X			X		
Incentives	X			X		
O&M		X				X
Utility/PA Admin Costs				X		X
Interconnection		X	X		X	
Tax Payments		X				X
Federal Tax Credits	X				X	
Capital/Financing Costs		X				X

As shown in the table, the bill savings experienced by the customer are a benefit in the PCT, but they are a cost in the RIM because other ratepayers bear the cost of maintaining the revenue requirement. In the TRC, these bill savings have no impact.[141] In addition, the incentives received by the participant are a cost for the non-participant but are not considered in the TRC because they are a benefit to participants and a cost to non-participants, thus canceling each other out..

a) The RIM and PCT Are Best Suited to Evaluate NEM Reform Tariff Proposals' Compliance With Statute

The Commission has undertaken an effort to consolidate and, to the extent possible, create consistency in demand-side cost-effectiveness policy in the Integrated Distributed Energy Resources (IDER) rulemaking, R.14-10-003. In D.19-05-019, the most recent policy decision

[140] This table includes only NEM-relevant benefits and costs, and therefore excludes combined heat and power and gas-fired DG inputs. This also excludes reliability costs and benefits and removal costs, which have not been quantified.

[141] The PCT measures gross savings to the customer, the RIM and TRC measure net savings of the program by subtracting some savings that would have occurred in absence of the program.

on cost-effectiveness frameworks, the Commission ruled that the TRC should be considered the "primary test for all Commission activities, including filings and submissions, requiring cost-effectiveness analysis of distributed energy resources, ***except where expressly prohibited by statute or Commission decision***".[142] However, the discussion in D.19-05-019 focuses primarily on aligning supply-side planning in the Renewables Portfolio Standard (RPS) program and the Integrated Resource Planning (IRP) proceeding[143] and the energy efficiency and demand response portfolios, which have traditionally used TRC.[144] The limited discussion pertaining to DG programs notes there may be instances where statute or commission decision require other tests.[145] In this case, TRC cannot meaningfully evaluate the costs and benefits of a tariff to all customers, as required by AB 327. Notably, D.19-05-019 spends little time discussing the regulatory usefulness of the participant perspective, the PCT. In fact, the decision only orders the consideration of the TRC, RIM and Program Administrator Cost test (PAC) when making determinations about program funding.[146]

If the Commission focuses exclusively or primarily on the TRC for comparing the cost-effectiveness of party proposals, little insight about the magnitude of the cost shift embedded in each proposal would be gained from the comparison. In the TRC, the benefit of bill savings experienced by the participating customer intuitively cancels out the cost born by other customers of increased rates to maintain the same revenue requirement. Similarly, any incentives in the program are a transfer payment from one group of customers to another.[147] Therefore, the TRC will not provide additional

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[142] D.19-05-019, OP 1. (emphasis added).

[143] D.19-05-019, p. 19: "It is the Commission's intention that the cost-effectiveness framework in this proceeding, the least-cost best-fit analysis in the Renewable Portfolio Standard program, and other valuation methods will be considered as part of the Common Resource Valuation Method being developed in the Integrated Resource Planning proceeding….Accordingly, we take a step closer to a universal cost-effectiveness framework and formally designate the TRC test as the primary cost-effectiveness test."

[144] D.19-05-019, p. 22: "Indeed, the demand response proceedings rely predominantly on the TRC to determine whether a program is cost-effective. While, the Energy Efficiency [sic] relies on both the TRC and the PAC, the Commission has expressed concern regarding the lower results of the TRC."; discussion of impacts to DR and EE continue on p. 23.

[145] D.19-05-019, p. 24, footnote 43.

[146] D.19-05-019, OP 2.

[147] The TRC captures only the participant's incremental measure costs above and beyond the incentive.

insight into any NEM successor tariff proposal that alters the level of compensation for onsite usage or exports and effects the level of bill savings for the customer, or any proposal that calls for incentives for income-qualified groups. TURN demonstrated this in its March 15 proposal by using its NEM PV and Storage cost-effectiveness tool to analyze various levels of export compensation and incentives,[148] and correctly notes, "…the TRC…does not materially vary based on the selected tariff design."[149] TURN concludes, "As a result, the TRC values are relatively constant across a wide range of successor tariff options, making it impossible to use the TRC to assess one tariff that provides lower compensation versus another that provides higher compensation."[150] In addition, E3's cost-effectiveness comparative analysis computed TRC metrics for each party proposal, which resulted in the *exact same score* for each proposal, Figure III-24. The primary difference between the CCSA result and all others is the system size assumptions, which assume a community solar installation with its lower $/Watt cost.

[148] *See* TURN March 15 proposal, pp. 28-29.

[149] *See* TURN March 15 proposal, p. 30. Further, "TURN's results show that the TRC for NEM 2.0 differs from the successor tariff results because of the assumed incremental cost of estimating or metering generation under TURN's approach. The actual design of the tariff, including various approaches to export compensation, netting, self-consumption, and grid charges, has no impact on the TRC results. Since the key features of tariff design do not affect TRC values, the TRC is not helpful in considering the alternative tariff proposals presented by various parties.

[150] *See* TURN March 15 proposal, p. 38.

Figure III-24
E3 Comparative Analysis Summary of TRC Scores

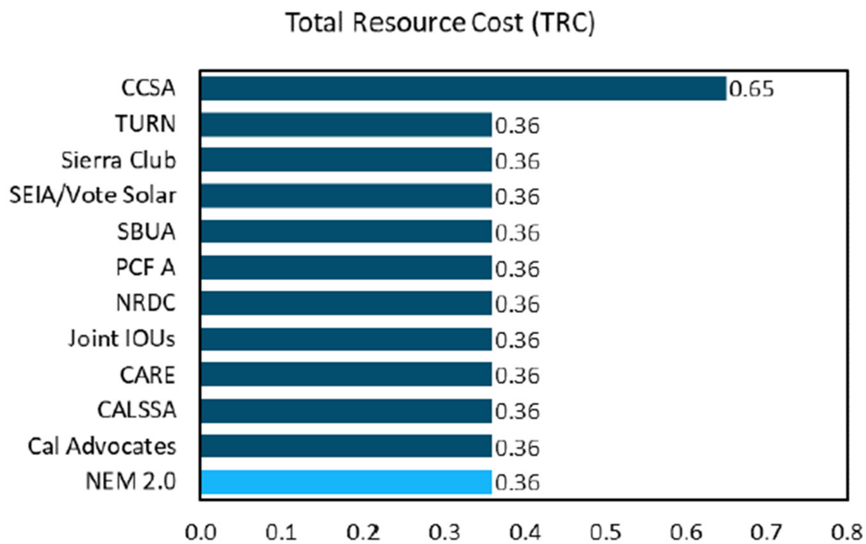

Figure 4: TRC for a 2023 residential non-CARE solar adopter in PG&E's service territory.

Source: E3 Comparative Analysis, Figure 4, p. 5

While the TRC is not useful in assessing the impacts of rate or tariff design, the SPM notes that the TRC is intended to identify cost-effectiveness relative to other resource options.[151] As noted above, the TRC benefits are simply the utility's avoided costs. The TRC costs are the total cost paid by either utility or participant to install the PV or PV + Storage system. This includes the upfront capital costs (or costs to finance the system) and interconnection costs, net of any federal incentives such as the Investment Tax Credit (ITC). Far and away the largest portion of TRC costs are the costs of the system itself. Due to economies of scale, larger systems have a lower unit cost and therefore a better TRC result, all else being equal. Verdant demonstrated this in its NEM 2.0 Lookback Study, where it showed that non-residential systems generally pass the TRC (B/C ratio greater than 1) because their system costs are lower than residential.[152] On the other hand, Verdant showed that NEM 2.0 for residential customers was not cost-effective from the TRC perspective (B/C ratio less than 1).

[151] SPM, p. 6.

[152] Verdant NEM 2.0 Lookback, p. 92. Citing LBNL Tracking the Sun report.

This finding is further demonstrated in E3's comparative analysis as shown in Figure III-24 above. The primary difference between the CCSA result and all others is the system size assumptions. From a TRC perspective, CCSA proposal illustrates large-scale projects, not customer-sited, are a more cost-effective option to achieve the optimal, or desired, level of PV penetration in the state. As demonstrated below in Figure III-25, the Integrated Resource Plan (IRP) proceeding conducted sensitivity analysis around the level of assumed rooftop PV adoption in their system planning model RESOLVE. This modeling shows that a scenario with lower customer-sited PV adoption results in lower total system costs, all else being equal.[153]

[153] 2017-2018 IRP Reference System Plan Model Results, Attachment A: Proposed Reference System Plan, p. 201. https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf.

Figure III-25
RESOLVE TRC Sensitivities

RESOLVE Output: Impact of Sensitivities on Incremental Cost (1/2)

All costs shown relative to Default Reference case

Sensitivity	Incremental TRC ($MM/yr) Default	Incremental TRC ($MM/yr) 42 MMT	Incremental TRC ($MM/yr) 30 MMT	Change from Reference ($MM/yr) Default	Change from Reference ($MM/yr) 42 MMT	Change from Reference ($MM/yr) 30 MMT
Reference	**$0**	**$239**	**$1,137**			
High EE	$120	$271	$1,048	+$120	+$33	-$89
Low EE	-$87	$282	$1,331	-$87	+$43	+$193
High BTM PV	$471	$677	$1,577	+$471	+$438	+$440
Low BTM PV	-$734	-$444	$480	-$734	-$682	-$657
Flexible EVs	-$66	$132	$935	-$66	-$107	-$202
High PV Cost	$240	$510	$1,419	+$240	+$271	+$282
Low PV Cost	-$280	-$137	$730	-$280	-$376	-$407
High Battery Cost	$264	$532	$1,470	+$264	+$294	+$333
Low Battery Cost	-$218	-$9	$617	-$218	-$248	-$521
No Tax Credits	$69	$382	$1,391	+$69	+$143	+$253
Gas Retirements	$351	$480	$1,233	+$351	+$241	+$96

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

Appendix B. Sensitivity Analysis

Given the discussion in the SPM and above of the relative strengths and weaknesses of each test, it is evident why this proceeding must provide greater consideration to the RIM and the PCT whose scores vary depending on the proposals. The RIM test is essential to understanding the rate and bill impacts of Commission policies on non-participating customers (comparable to the "cost shift" metric discussed above in this chapter), and the PCT is essential to understand participant customer economics (comparable to the "payback period" metric discussed in this chapter).

Pursuant to Public Utilities Code section 2827.1(b)(1), the Reformed Tariff must "ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably". While parties may debate the exact definition of "grow sustainably," from a SPM perspective the test best-suited to answer quantitatively assess customer interest in renewable DG is the PCT while the RIM test provides the context of how customer adoption impacts non-participants. Assessing sustainable growth requires an understanding of both perspectives.

3. <u>Avoided Cost Calculator (ACC) Updates Should be Considered in Cost-effectiveness and Incorporated into Tariff Design</u>

The Avoided Cost Calculator (ACC) is used to determine the primary energy benefits (*i.e.*, avoided costs to all customers) and evaluate the cost-effectiveness of distributed energy resources across Commission proceedings. The ACC provides an hourly forecast of the marginal costs a utility would avoid over a 30-year period if a distributed energy resource avoided the provision of energy, including the cost of: generation capacity, energy, ancillary services, greenhouse gas emissions, and transmission and distribution capacity. The ACC is meant to capture only those categories of costs borne by customers on their rates and bills. While there has been some discussion of including other participant benefits, such as the individual benefit of increased resilience due to a residential customer installing solar + storage, or the societal benefit of increased economic value and job creation in the rooftop solar industry in California, these considerations are appropriately not included in the ACC and should not be included in assessing the cost-effectiveness of successor tariffs. Including these non-energy benefits in cost-effectiveness calculations simply skews the analysis resulting in programs that have little quantifiable energy savings benefits as reflected in the ACC and potentially resulting in a program that increases rates for all customers, while benefitting only some.

D.19-05-019 established a process to update the ACC annually—minor changes through a CPUC resolution in odd-numbered years and major and minor changes that require a final decision in even-numbered years—to improve accuracy and more closely reflect changing state policies.[154] Such updates have included relatively minor updates such as incorporation of more recent gas and energy price forecasts, inclusion of more recent historical data and utility values (e.g., T&D marginal costs as proposed or approved by the Commission), and the correction of calculation errors.[155]

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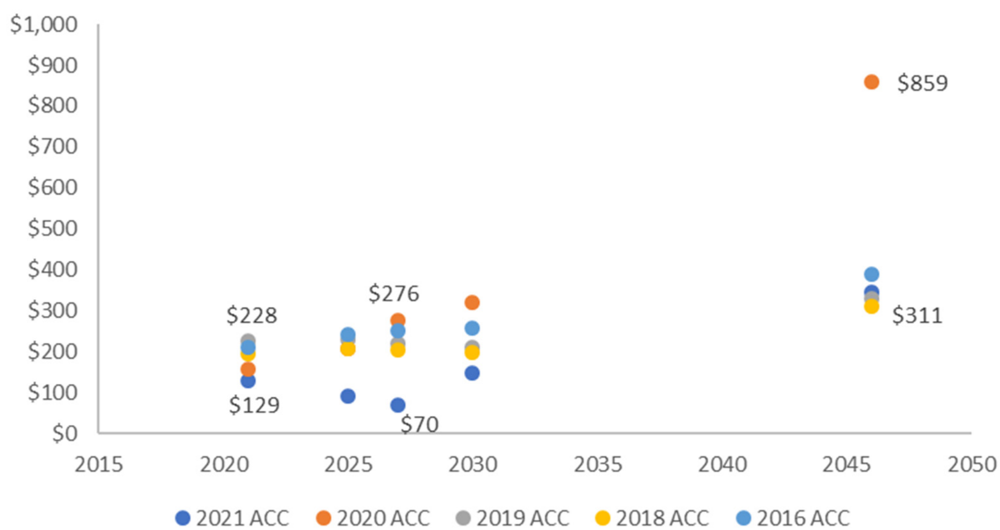
[154] *See also* D.20-04-010 at p. 5.

[155] *See* Resolution 5014-E.

There also have been major methodological updates such as the adoption of the "No New DER" Scenario, addition of avoided methane leakage costs to the calculator, and removal of "avoided RPS costs" from the calculator. Given the evolving nature of the ACC and its sensitivity to fluctuations in the energy markets or changes in policy priorities, it is unsurprising that the avoided cost forecast has changed, and will continue to change, over time.

For example, Figure III-26 below compares the annual average avoided cost forecast for the years 2021, 2025, 2027, and 2030 from the 2020 ACC model with the annual average avoided cost forecast for those same years from the 2016 ACC model. While the short-run annual ACC results are consistent and have not changed dramatically between updates, the mid- and long-run values vary widely, demonstrating how sensitive those forecasts are to input and assumption changes.

Figure III-26
Representative ACC Evolution for SCE Climate Zone 6
(Annual Avoided Cost /kW Installed)



For this reason, proposals to tie NEM compensation to the ACC must (1) rely on short-run ACC values as they are inherently more accurate and less speculative than mid- or long-run values and (2) be updated annually to reflect the most recent ACC inputs and assumptions. Indeed, while the ACC has not historically been used to set compensation levels, other programs that link compensation to avoided costs update those values frequently to ensure they are accurate and reflective of current market conditions.[156] This is further illustrated in Sacramento Municipal Utility District's (SMUD's) long-term value of solar study, which used similar methods as the ACC to determine solar and solar + storage value over the 2020-2030 time horizon.[157] The study concluded the near-term value of solar to be in the range of $0.03/kWh to $0.07/kWh for 2020 installations, while the long-term value declined to $0.04/kWh for 2030 installations.[158] This declining value in future years is attributed to declining wholesale market prices as more utilities throughout the west add large quantities of solar resources,[159] a finding that is mirrored in the 2021 ACC.

The need to update annually based on the most recent ACC and to use only short-run values is even more critical when the compensation is tied to hourly (or an aggregation of hourly) avoided costs. For example, while the annual average avoided cost for the year 2021 only changed 3% between the 2016 and 2020 versions of the ACC, the average difference at the hourly level was 53%. Similarly, the average difference at the hourly level for the years 2030 and 2046 was 95% and 153%, respectively.

4. The Joint Utility Reform Tariff Proposal Balances the Need to Ensure Sustainable Customer Solar Growth While Also Ensuring Fair and Equitable Cost Responsibility, as Shown by the SPM Results

The Commission established a phase to this proceeding to analyze the cost-effectiveness of party successor tariff proposals on an apples-to-apples basis.[160] To do so, they contracted with E3 to collect the core elements of each party proposal and compute first-year cost shift, simple payback, and lifecycle results of three SPM tests: TRC, RIM and PCT. E3's comparative analysis is meant as a guide to the CPUC to see how party proposals address cost misalignment, with the goal of comparing

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[156] For example, the Qualifying Facilities/Combined Heat and Power Program approved in D.10-12-035 compensates generators based on Short Run Avoided Cost (SRAC), which is updated monthly. *See* Resolution E-4246.

[157] *See* Sacramento Municipal Utility District Value of Solar and Solar + Storage Study Technical Report: https://www.smud.org/-/media/Rate-Information/NEM/VOSstudy.ashx

[158] *Ibid*, pp. 53-57.

[159] *Id.,* p. 2.

[160] *See* Email Ruling Noticing April 22, 2021 Workshop and Revising Procedural Schedule, April 8, 2021.

proposals transparently and consistently using a common set of inputs.[161] We have performed similar calculations to determine simple payback and cost shift, which may differ from the results of E3's analysis due to a variety of assumptions made in the analysis, notably around customer annual electricity consumption, the default rate[162] and system sizing. Regardless, E3's results are instructive because they illustrate how parties propose to address, or fail to address, cost inequities of NEM 2.0.

As discussed elsewhere in this testimony, we are focused on reducing cost burdens to non-participating and income-qualified customers, and on incentivizing storage paired systems, which can provide better alignment between grid and customer benefits. These principles are borne out in comparing cost-effectiveness results from the participant (represented by the PCT) and non-participant (represented by the RIM) results for each of these scenarios, shown in Table III-12 below.

Table III-12
E3 Cost-Effectiveness Results for Joint IOU DGST Proposal in 2023

Metric/Utility	PG&E		SDG&E		SCE	
	PCT	RIM	PCT	RIM	PCT	RIM
NEM 2.0 Non-CARE Res Solar	3.28	0.11	4.49	0.09	2.74	0.21
Proposed Non-CARE Res Solar	0.58	0.61	1.47	0.26	0.75	0.76
Proposed CARE Res Solar	0.93	0.38	1.60	0.24	0.89	0.64
Proposed Non-CARE Res Solar + Storage	0.85	0.58	1.62	0.39	1.20	0.68

The status quo NEM 2.0 tariff shows a large imbalance between participant benefits in the PCT and non-participant costs in the RIM. Our proposal shows lower PCT scores for solar alone, but these are offset by higher RIM scores compared with NEM 2.0. Additionally, both CARE solar and Non-CARE solar + storage each score higher under the PCT than for the non-CARE solar alone. As described above and further in Chapter 4, our Reform Tariff proposal intentionally tries to drive these outcomes towards reducing cost shift, encouraging income-qualified participation in customer technology and incenting the growth of residential storage.

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161 Cost-Effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020: A Comparative Analysis, p. 1

162 E3's analysis calculates pre-solar bills based on existing default TOU rates. The Utilities assumed the proposed default cost-based rates for SDG&E (TOU-DER) and PG&E (E-DER) for both pre and post bills in order to control for bill impacts caused by structural differences in the rate and isolate the impact of the successor tariff. This change will generally lower the first-year cost shift and increase RIM scores, all else equal.

D. Conclusion

It is abundantly clear that the current NEM tariff design and volumetric residential rates provide compensation for energy exported to the grid by distributed solar well above the avoided cost of such energy. Given the significance of the existing and projected NEM program cost shifts, it is imperative to limit additional customers from taking service on these tariffs and the Commission must address this now. Chapters 4 and 5 of this testimony details our proposal to help limit this cost shift, promote the adoption of solar paired with storage, incentivize solar and storage adoption by income-qualified customers, and provide a more equitable framework for the NEM successor tariff. We believe our Reform Tariff provides the balance needed for this stable and mature technology.

IV.

THE JOINT UTILITIES PROPOSED REFORM TARIFF

A. Introduction and Purpose

This chapter presents the four main elements of the Joint Utilities' core distributed generation successor tariff (DG-ST or Reform Tariff). Those elements are: (1) a more cost-based residential default rate; (2) value-based export compensation rates for all Reform Tariff customers; (3) a grid benefits charge (GBC) for residential customers and non-residential customers; and (4) instantaneous time-of-use (TOU) netting and monthly true-ups. This chapter also presents our proposed "Value of Distributed Energy" (VODE) Tariff; Virtual Net Energy Metering (VNEM) tariffs; other elements of the proposed non-residential Reform Tariff; and standardization of dispatchability requirements.

The four core elements of our proposed tariff are designed to work together to reduce the cost shift from participating to non-participating customers and maintain a value proposition for participating customers, emphasizing the importance of prioritizing solar paired storage installations over standalone solar. Each component of this proposal is essential and non-severable to ensure that the Reform Tariff is equitable for all customers while also sustaining growth of customer-sited generation and increasing such growth among residential customers in disadvantaged communities. As such, while this testimony individually describes the various components of our proposed tariff, the Commission should consider each component as part of a total package.

Specifically, remaining sections of this chapter details our proposed Reform Tariff, as follows:

1. Default of residential Reform Tariff customers to specific residential rates;
    a. New PG&E rate: "E-DER"
    b. New SDG&E rate: "TOU-DER"
    c. Existing SCE rate: "TOU-D-PRIME"
2. Value-Based Export Compensation Rates (ECR);
3. Instantaneous TOU Netting and Monthly True-ups;
4. Grid Benefits Charge (GBC) for residential customers;
5. Grid Benefits Charge (GBC) for non-residential customers;

6. Value of Distributed Energy (VODE) Tariff;
7. Elimination of Standby Exemption for non-NEM Solar Generators Under 1 MW
8. Virtual Net Energy Metering (VNEM) Tariffs;
9. Enabling Dynamic Load Management Capabilities; and
10. Cost Recovery for Income-qualified and Storage Programs

All information provided in this testimony is based on the 2021 Avoided Costs Calculator version released May 3, 2021,[163] PG&E's current effective rates as of March 1, 2021,[164] SDG&E's current effective rates as of June 1, 2021,[165] and SCE's current effective rates as of June 1, 2021.[166]

1. Overview: Components and Structure

Our proposed Reform Tariff[167] has four main elements, as shown in Figure IV-27 below:

1. Value-based export compensation rates (ECR) that are decoupled from the retail rate;
2. A residential default cost-based rate;
3. Instantaneous time-of-use (TOU) netting and monthly true-ups; and
4. A Grid Benefits Charge (GBC) based on solar system size.

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[163] Draft Resolution E-5150.

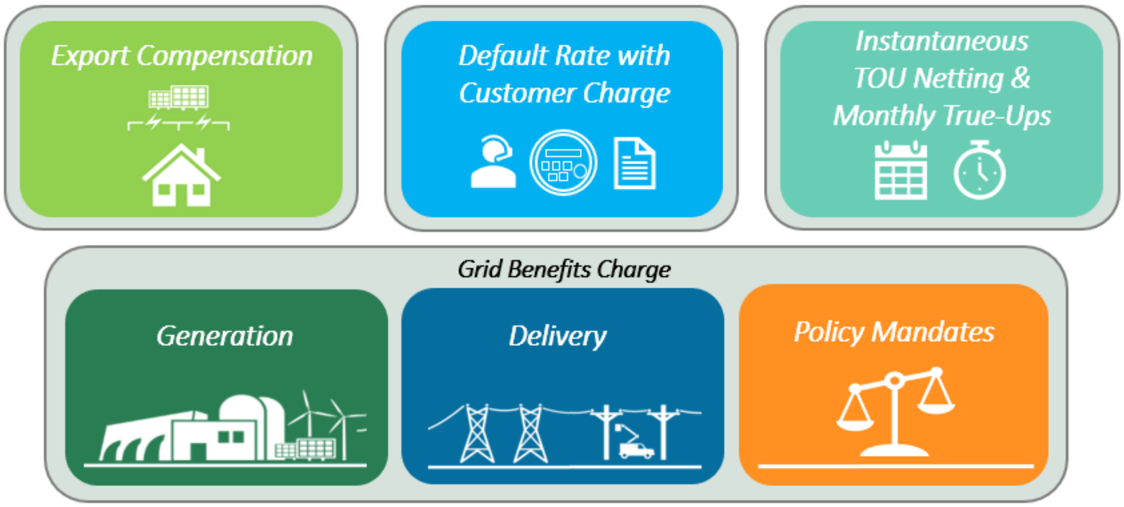
[164] Advice Letter (AL) 6090-E-A.

[165] AL 3756-E.

[166] AL 4488-E-A.

[167] Unless otherwise stated, residential DG-ST customers referred to are non-CARE, non-FERA.

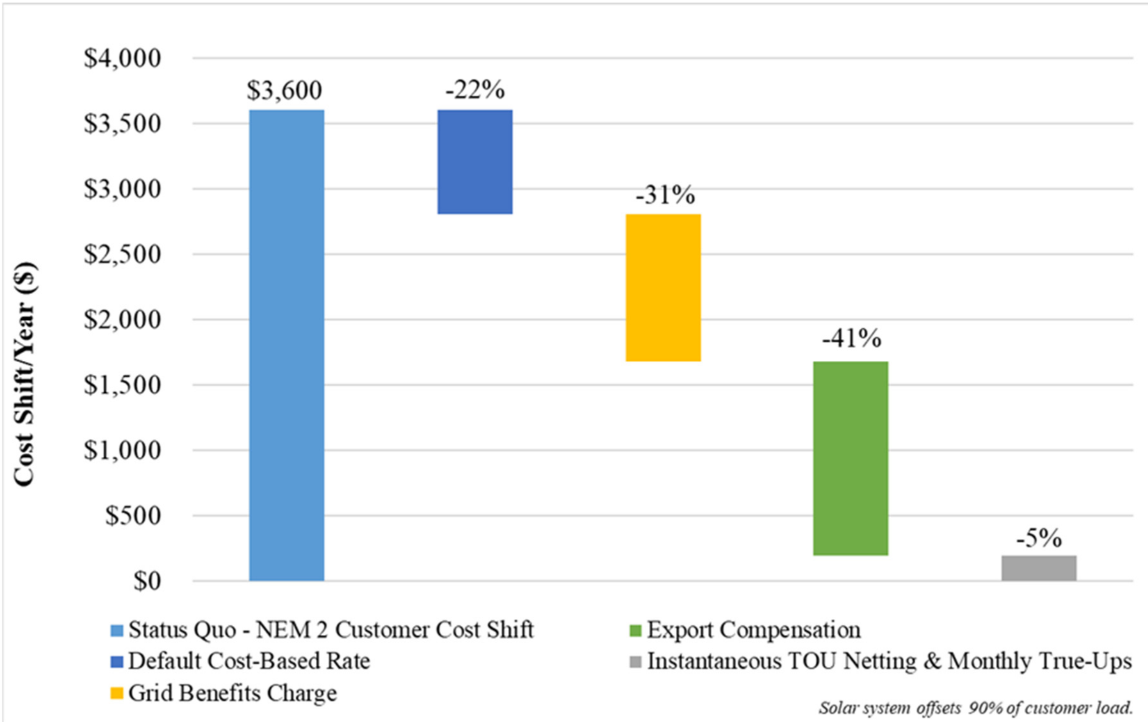
Figure IV-27
NEM Reform Tariff Components



We are proposing a net billing structure, where all energy delivered to the customer on meter Channel 1/Channel A is billed at the retail rate, and all energy exported to the grid on meter Channel 2/Channel B is compensated at the ECR, as discussed in this chapter.

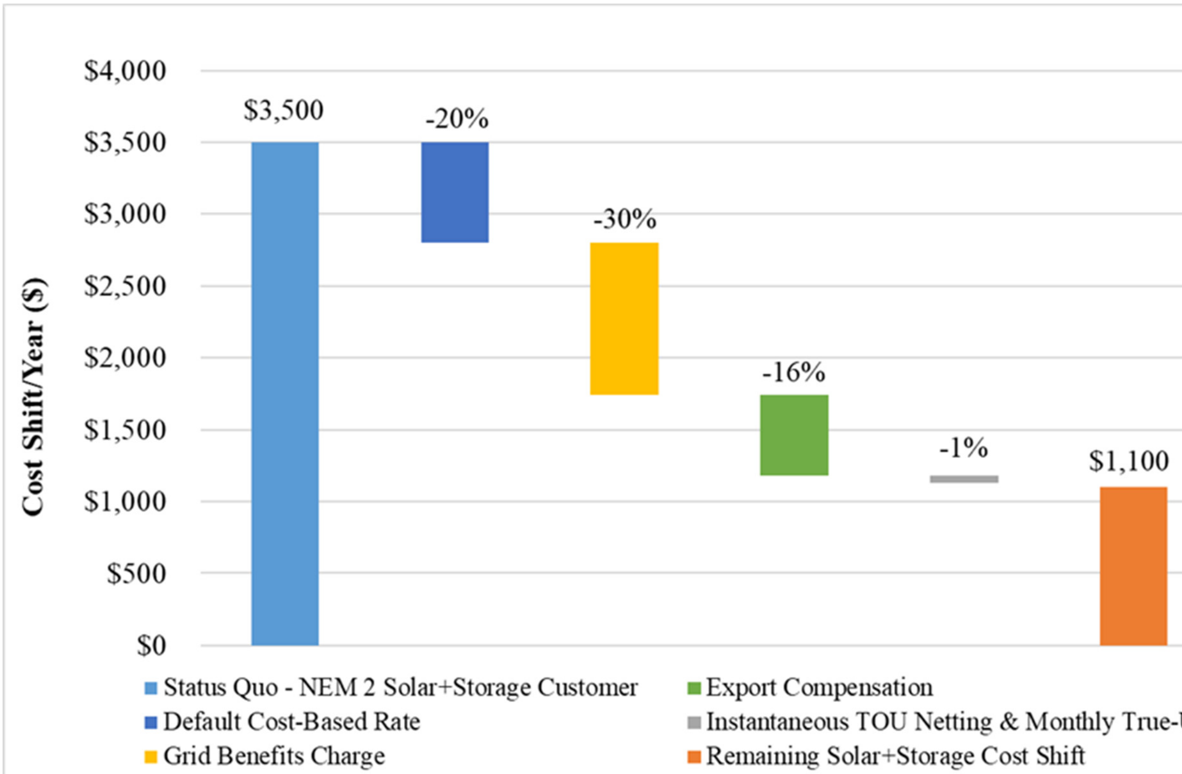
Figure IV-28 and Figure IV-29 below illustrate the cost shift reduction from each of our proposed elements. Adoption of our proposal will result in no cost shift from standalone solar customers on the Reform Tariff. Figure IV-28 also emphasizes the importance of fixed cost recovery through the GBC; solar paired storage customers export little of their generation, and as such, reducing the export compensation rates does little to reduce the cost shift for these customers. As California moves toward a solar paired storage model, it is imperative that the Commission adopt fixed cost recovery for Reform Tariff customers. Changing the export compensation rates only affects the percentage of generation that is exported. For example, if a solar + storage system exports 20% of generation, the maximum the cost shift can be reduced by only changing export compensation is 20%. As discussed in Chapter I, California must move from a standalone solar model toward a solar + storage model, and therefore, the Commission must adopt a level of fixed cost recovery to effectively resolve the cost shift. We have proposed fixed cost recovery through two policy instruments: a residential default rate with a cost-based customer charge and a Grid Benefits Charge.

Figure IV-28
Illustrative Standalone Solar Customer Annual Cost Shift Reduction –
Proposed NEM Reform Tariff[168]



[168] In practice the cost shift reduction for an individual customer may not be reduced to zero due to variation in percentage of generation exported. We discuss how our proposal will update the calculation of the GBC annually to ensure the most accurate cost recovery for each class of customers.

Figure IV-29
Illustrative Solar Paired Storage Customer Annual Cost Shift Reduction – Proposed NEM Reform Tariff[169]



First, new residential Reform Tariff customers would be defaulted to a cost-based rate. Second, those customers will be compensated for exported generation using a net billing structure where exports are compensated based on their value, decoupled from the retail rate. Customers will pay the applicable retail rate for any imports from the grid. Third, customers will be assessed a GBC based on their rooftop solar system's installed capacity (in kilowatt- [kW] CEC-AC[170]). The grid benefits charge will be designed to recover costs that are shifted due to solar customers' onsite consumption, which largely are the result of NEM customers not reducing their total consumption (as compared to the reduced consumption seen through energy efficiency measures). With NEM, onsite consumption does not reduce total demand and the utilities must maintain the ability to meet demand at any point the solar

[169] In reality, the NEM 2.0 cost shift from a solar+storage customer will vary individually due to battery sizing and dispatch patterns.

[170] As defined in each utility's NET ENERGY METERING (NEM) GENERATING FACILITY INTERCONNECTION APPLICATION Form.

photovoltaic (PV) system is not producing. The default rate fixed charge and GBC communicate to Reform Tariff customers that they both use and rely on the grid after adopting distributed solar or solar paired storage.

We propose non-residential customers continue to take service on their current rate schedules,[171] as non-residential customers typically have multi-part, more cost-based rates, but would be assessed a GBC based on their underlying rate and be compensated per the proposed ECR.

Finally, for both residential and non-residential Reform Tariff customers, true-ups will occur monthly and exports may only be netted within their respective time-of-export period. TOU netting will provide more accurate price signals for customers, further encourage load shifting, and ensure that customers exporting during the middle of the day are not able to use these credits to offset increased consumption during the evening peak period.

2. Storage Considerations

Our proposal recognizes the "win-win" impact of pairing storage systems with distributed solar. For participants, storage provides resiliency during grid outages and the ability to reduce usage during higher price periods during blue sky conditions. For non-participants, solar paired storage has the potential to provide more benefits to the grid, if that paired storage is operated in a manner that maximizes grid value.

Behind-the-meter (BTM) battery storage systems can provide grid benefits. For example, as more renewable generation and solar generation interconnects with the grid, the grid operator curtails more renewable electricity every year. Today, when BTM solar generation peaks during the midday hours, there is no mechanism in place to curtail excess energy flowing into the grid, as exists for utility-scale power plants. Paired storage systems can help to mitigate this issue, when coupled with the right price signals.

To counter this inefficiency, our proposal provides incentives for customers to store energy in their BTM batteries during the high production, low-value, hours of the day (*e.g.*, during high solar

[171] SCE's small commercial customers in the TOU-GS-1 rate group will be placed on Option TOU-GS-1-LG. Option TOU-GS-1-LG uses the same multipart rate structure as the applicable underlying rates for the other non-residential rate groups.

production midday) and to consume or export that energy in the late afternoon and evening when it is most valuable and more likely to displace non-renewable generation. This results in a lower payback period for solar + storage systems as compared to standalone solar (Table IV-13), since customers are offsetting a higher average retail rate. Additionally, we propose that solar + storage systems be configured in a way to enable more modern, direct load control, and operation of the resources, when the systems are available.

3. <u>Current NEM Customers Receive 5x Payback Over 20 Years</u>

Existing NEM customers in our service territories see rapid paybacks on their systems and continue to receive subsidized electric bills for 20 years after their interconnection date. These current payback periods for customers installing rooftop solar under the existing NEM program are shown in Table IV-13. Falling technology costs and increasing utility rates have contributed to paybacks of 4 years or less, but current NEM policy allows for the same financial benefits for 20 years,[172] leading to a customer return on investment at least five times greater than the initial purchase price.

The proposed changes bring estimated payback periods for participating customers more in line with system lifetimes and other reformed jurisdictions, as discussed in more detail in Chapter II, which generally have paybacks for standalone solar of at least 10 years. Further, current paybacks are shorter for standalone solar than solar + storage. Our proposal incentivizes adoption of storage by offering a shorter payback period for systems that are paired with storage.

If adopted in full, new Reform Tariff customers who purchase their systems would see the following average payback periods.

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[172] D.14-03-041, OP 1.

Table IV-13
Existing NEM 2.0 Program – Illustrative Estimated Payback Period for New Participating Customers[173]

Utility	Estimated Payback (Standalone Solar)	Estimated Payback (Solar+Storage)
PG&E	4 years	6 years
SCE	4 years	7 years
SDG&E	3 years	5 years

Table IV-14
Joint Utilities Proposal -- Illustrative Estimated Payback Periods of Participating DG-ST Customers

Utility	Estimated Payback (Standalone Solar)	Estimated Payback (Solar+Storage)
PG&E	19 years	14 years
SCE	18 years	12 years
SDG&E	15 years	11-years

As discussed in Chapter II of this testimony, the solar market has matured significantly and the significant subsidies adopting customers enjoy today are no longer needed. The payback periods above more accurately reflect the financial value of exports from a standalone solar system and a paired storage system to the grid. Storage, which is necessary for PV systems to fully deliver value to both the grid and Reform Tariff customers, maintains a payback period that is well aligned with paybacks in other jurisdictions with lower rates of solar adoption. Pairing new solar with storage is necessary to encourage effective use of renewable resources and the Reform Tariff should clearly incentivize the adoption of storage for new Reform Tariff customers.

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[173] These payback period scenarios assume outright purchase of customer-sited systems. Modeling conducted in the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM), and use NREL's Annual Technology Baseline report for system costs.

4. **More Cost-Based Rates are Essential for Reform Tariff Customers**

We are proposing new Reform Tariff customers be enrolled on rates with cost based, non-tiered TOU differentials and fixed charges. It is critical for Reform Tariff customers to take service on rates that reflect accurate prices and that any incentives or subsidies are direct and transparent. This basic principle of connecting cost drivers with cost recovery is more important now as California moves towards its decarbonization goals. Multi-part rate designs are "...intended to reflect the cost realities of an increasingly decarbonized bulk power grid that is composed largely of fixed costs and decreasing variable costs."[174]

As California moves towards its decarbonized future in an environment where the threat of extreme weather events fueled by climate change will increase, grid infrastructure investments play a primary role in achieving these goals. A portion of these investments will be to harmonize grid conditions and the bi-directional flow of energy from an increasing amount of distributed generation, making recovery of grid costs equally applicable regardless of the direction of the flow of energy. Similarly, all customers benefit from infrastructure improvements (e.g., system hardening to mitigate wildfire) and should thus contribute to recovery of these costs, among others.

In Rulemaking (R.) 12-06-013 the CPUC adopted a set of ten Rate Design Principles (RDP).[175] Table IV-15 below presents the RDPs in four categories consistent with D.15-01-007: (1) cost of service; (2) affordable electricity; (3) conservation; and (4) customer acceptance. Our proposal seeks to balance these RDPs, working to promote energy policy that aligns with a vision of technological innovation and choice while providing a clean, safe, and sustainable future.

The current NEM programs are misaligned with nearly all these principles. The Commission must recognize some customers can size their systems to bypass nearly all volumetric energy-only ($/kWh) rates, and distributed generation customers will bypass an increasing proportion of volumetric rates as more customer pair their solar generation with energy storage batteries and as technology improves. Without a more cost-based rate structure and charges to ensure non-participant indifference,

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[174] CPUC, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California," January 28, 2021, p. 33.

[175] R.12-06-013, at pp. 27-28.

adopting customers will continue to shift an increasing amount of costs to these nonparticipants. The Commission has an opportunity to move a subset of residential customers onto more cost-based rates that will, by design, result in a lower cost shift than other currently available rates.

Table IV-15
CPUC Rate Design Principles

Cost of Service RDP	Affordable Electricity RDP	Conservation RDP	Customer Acceptance RDP
(2) Rates should be based on marginal cost; (3) Rates should be based on cost-causation principles; (7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; (8) Incentives should be explicit and transparent; (9) Rates should encourage economically efficient decision-making.	(1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	(4) Rates should encourage conservation and energy efficiency; (5) Rates should encourage reduction of both coincident and non-coincident peak demand.	(6) Rates should be stable and understandable and provide customer choice; (10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

While the Commission has made significant strides in improving the design of residential rates, including consolidating the tiers and defaulting most customers to time-of-use rates,[176] these positive changes have not prevented NEM customers from inequitably shifting an enormous amount of costs to non-participating customers. The underlying rates NEM customers are enrolled on today have several shortfalls that contribute to the significant cost shift placed onto non-participating customers.

Current cost recovery for residential customers is still disconnected from cost-basis, as it is almost entirely volumetric, or kilowatt hour (kWh) rates. The only exceptions to these volumetric rates are the minimum bill, which is approximately $10 and $5 per month for non-CARE and CARE customers, respectively, and can only be increased by: (1) Consumer Price Index (CPI) annually or

[176] D.15-01-007, OPs 9-11.

(2) reviewing in a General Rate Case Phase 2,[177] and a handful of optional rates with fixed charges that have eligibility restrictions. It is imperative that the Commission adopt a default rate structure that more closely reflects the cost to serve customers and ensure that participating Reform Tariff customers do not continue to shift costs, driving up the rates and bills of non-participating customers. In addition, although NEM 2.0 customers are required to take service on TOU rates, they can still choose rates that include a tiering mechanism, or baseline credit, which provides a lower charge for usage deemed to be essential, but distorts the actual cost signals.

Adopting our default tariff will serve the dual purposes of aligning both Reform Tariff and nonparticipating customer's electricity rates by establishing a more transparent and cost-based, sustainable structure for Reform Tariff customers and increasing affordability through a reduced cost shift for nonparticipants. More cost-based rates that do not have tiers and include customer charges will help to ensure that customers pay for fixed costs and receive appropriate price signals.

5. The Commission Should Not Wait Until Residential Fixed Charges are Approved for All Customers

The Commission should adopt our proposed cost-based rates as the default rate option for successor tariff customers. These rates have higher fixed charges and therefore are more aligned with equitable cost recovery. Such rates, because of their higher fixed charges, have lower volumetric charges, which will encourage electrification.

The Commission should not defer action on fixed charges in this proceeding under the assumption that a residential customer class fixed charge will be adopted for each utility in the future. Fundamentally, the policy goal of nonparticipant indifference in NEM and the Reform Tariff cannot be achieved by a hypothetical $10 fixed charge that applies to all participants and nonparticipants. The Commission is severely limited in the amount of residential customer class fixed charge it has the authority to adopt.[178] A fixed charge at the statutory maximum $10/month would reduce SDG&E's

[177] D.15-01-007, at p. 227.

[178] Public Utilities Code § 739.9(f) imposed a $10 cap on residential fixed charges for non-CARE customers and a $5 cap for CARE customers.

current Residential NEM cost shift from $573 million per year[179] to $538 million per year, a reduction of approximately 6%. It is the Commission's responsibility to ensure that non-participating customers do not bear the cost of a future successor tariff. Deferring the issue of fixed charges for solar customers will result in a continued cost shift to nonparticipating customers.

It is unknown whether the Commission will adopt default residential fixed charges in a future proceeding. Therefore, the Commission should not assume in this proceeding that residential fixed charges will be adopted as justification for declining to adopt our default Reform Tariff rate proposals. PU Code § 2827.1(c)(7) specifically allows for the Commission to approve fixed charges for solar customers that are different from non-solar residential customers. The Commission should not pass up the opportunity to meaningfully reduce volumetric rates for Reform Tariff customers and require more cost-based rates.

The default Reform Tariff rates proposed by us are designed to recover residential class authorized revenue requirements and based on marginal cost-causation. As evidenced in PG&E's 2020 GRC Phase 2, both residential and non-residential NEM customers in that proceeding were shown to have a higher cost to serve than non-NEM cohorts.[180] We are supportive of default fixed charges for all residential customers, but this policy instrument, which would be addressed outside this proceeding, cannot achieve NEM or Reform Tariff non-participant indifference.

Our default rate Reform Tariff proposal will not only ensure that participating customers take service on a rate that is closer to their cost of service, thereby lowering the cost shift to non-participants. It also has the potential to encourage electrification through its lower volumetric rate for non-Reform Tariff customers who choose this rate on an opt in basis. This rate design is a first step on the path toward the state's electrification goals. More cost-based, multi-part rate design is necessary to lower volumetric kWh energy rates. Without significant changes, high volumetric rates will be a barrier to electrification.

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[179] Calculated as of June 1, 2021.

[180] PG&E GRC Phase 2 A.19-11-019, Prepared Testimony Chapter 1, Table 1-2, Chapter 8, pp. 8-13 to 8-20, marginal distribution customer costs – NEM vs. non-NEM.

6. Current NEM Customers Should Transition to Our Reform Tariff At The End of Their Legacy Period

As previously discussed in this Chapter, NEM 1.0 and NEM 2.0 receive substantial compensation for their investment over their legacy period—up to five times their payback period. Because the compensation for NEM 1.0 and NEM 2.0 is so generous and the subsidies are provided over such a long period of time – until 2041 for customers installing distributed generation today –the Commission must ensure that non-participants do not continue to subsidize these customers after their legacy period ends. Thus, after NEM 1.0 and 2.0 customers' legacy term ends, the Commission should require those customers to be served on the Reform Tariff.

B. Proposed Default Residential Rate for Reform Tariff Customers

The following sections detail the proposed default base TOU rate for Reform Tariff customers.

1. PG&E

a) PG&E's Residential Rates

PG&E's residential rates consist of the following rate components

- Transmission – charge for the delivery of high-voltage electricity from power plants to distribution points near customers' homes.
- Distribution – charge to distribute power over lower voltage lines to customers. It includes power lines, poles, transformers, repair crews and emergency services, along with public policy programs such as the Self Generation Incentive Program (SGIP).
- Public Purpose Programs (PPP) – charge for the costs of certain state-mandated programs (such as income-qualified and energy efficiency programs.
- Nuclear Decommissioning (ND) – charge for the retirement of nuclear power plants.

- Ongoing Competition Transition Charges (CTC) – charges for the costs for power plants and long-term power contracts approved by state regulators that have been made uneconomic by the shift to competition.
- New System Generation Charge (NSGC) – charge for the costs associated with generation power suppliers that the CPUC has determined should be recovered from all benefiting customers. Within the CPUC planning processes, these are referred to as "Cost Allocation Mechanism" ("CAM") resources.
- Conservation Incentive Adjustment (CIA) – this rate component does not result in net revenue collections but reflects the handling of rate subsidies required by legislation and applied to residential usage up to 100% of baseline allowances. The associated rate cap subsidy amounts that apply to usage up to 100% of baseline allowances are tracked through add-on charges to residential rates for usage in excess of 100% of baseline allowances.
- California Wildfire Fund Non-bypassable Charge – charge for partially funding a source of relief money to pay or reimburse eligible wildfire-related claims.
- Commodity – Charges for energy provided to PG&E bundled customers. Includes costs associated with electricity generation and procurement from both utility-owned generation and third-party power purchase agreements (PPA).

Like the other utilities, PG&E's residential cost recovery is almost entirely through volumetric rates. The only exception to volumetric cost recovery is a delivery minimum bill of 10 dollars-per-month.

b) <u>PG&E's Reform Tariff Default Residential Rate Proposal</u>

Like SDG&E (discussed below), PG&E proposes a new non-tiered TOU rate in this proceeding that will serve as the default rate for residential Reform Tariff customers. This rate would be available to all residential customers. This rate would feature the same TOU periods as the current EV2 rate but would feature a customer charge based on fully scaled customer costs and cost-based TOU differentials. As with SDG&E's proposal, these cost-based TOU differentials can provide accurate price signals to customers with behind-the-meter storage. Further, by appropriately collecting customer related costs through a monthly charge, PG&E would be able to offer a correspondingly lower Grid Benefits Charge while achieving equivalent fair cost responsibility from Reform Tariff customers.

While PG&E's proposal is not based directly on this finding, it is important to note that PG&E's 2020 GRC Phase 2 cost-of-service study found that existing residential NEM customers have much higher marginal customer costs ($17.32/month) compared to all residential customers ($11.52/month).[181] Fully scaled by an equal percentage of marginal costs (EPMC) multiplier, this would justify a $31.05/month customer charge for new solar customers were they a separate customer class. PG&E proposes a customer charge of only $20.66/month for new solar customers, approximately a third less than would be justified were they a separate customer class.

PG&E would also be open to residential Reform Tariff customers taking service on another non-tiered TOU rate, such as EV2 or E-ELEC, the latter of which is not yet approved in PG&E's 2020 GRC Phase 2. However, both would require higher associated Grid Benefits Charge levels to ensure fair distribution cost contribution from Reform Tariff customers. Further, if in the future other residential rate designs with novel features (such as real time pricing-based components) are approved by the Commission, it would be reasonable to allow Reform Tariff customers with battery storage to take service on such a rate. However, this would also require that real time pricing rate to either have a similar rate design as E-DER for non-real time components or have a separately calculated Grid Benefits Charge.

PG&E's proposed E-DER rates as of March 2021 are in Table IV-16 below.

[181] A.19-11-019.

Table IV-16
PG&E's E-DER Rate – Non-CARE

Description	Unit	Total Rate
Customer Charge	$/month	$20.66
Energy Charges:		
Summer:		
On-Peak	$/kWh	0.40
Part-Peak	$/kWh	0.27
Off-Peak	$/kWh	0.22
Winter:		
On-Peak	$/kWh	0.23
Part-Peak	$/kWh	0.21
Off-Peak	$/kWh	0.20

2. <u>SDG&E</u>

a) <u>SDG&E's Residential Rates</u>

SDG&E's residential rates consist of the following rate components:

- Transmission – charge for the delivery of high-voltage electricity from power plants to distribution points near customers' homes.
- Distribution – charge to distribute power to customers. It includes power lines, poles, transformers, repair crews and emergency services.
- Public Purpose Programs (PPP) – charge for the costs of certain state-mandated programs (such as income-qualified and energy efficiency programs).
- Nuclear Decommissioning (ND) – charge for the retirement of nuclear power plants.
- Ongoing Competition Transition Charges (CTC) – charges for the costs for power plants and long-term power contracts approved by state regulators that have been made uneconomic by the shift to competition.
- Reliability Services (RS) – charge for services provided by generating facilities to maintain system reliability.

- Local Generation Charge (LGC) – charge for the costs associated with generation power suppliers that the CPUC has determined should be recovered from all benefiting customers.

- Total Rate Adjustment Component (TRAC) – reflects the handling of rate subsidies required by legislation and applied to residential usage up to 130% of baseline allowances. The associated rate cap subsidy amounts that apply to usage up to 130% of baseline allowances are tracked through add-on charges to residential rates for usage more than 130% of baseline allowances.

- California Wildfire Fund Non-bypassable Charge (WF-NBC) – charge for partially funding a source of relief money to pay or reimburse eligible wildfire-related claims.

- Commodity – Charges for energy provided to SDG&E bundled customers. Includes costs associated with electricity generation and procurement from both utility-owned generation and third-party power purchase agreements (PPA). Includes the Department of Water Resources Credit (DWR Credit).

- Power Charge Indifference Adjustment (PCIA) – cost responsibility surcharge assessed to unbundled customers designed to recover above market costs of utility procurement.

b) <u>SDG&E's Default Residential Rate Proposal (TOU-DER)</u>

SDG&E's residential Reform Tariff default rate design proposal in this testimony is designed to follow and balance the Commission's 10 RDPs. SDG&E's default proposed rate is intended to transition Reform Tariff customers to a more cost-based rate structure while providing stability and promoting acceptance. SDG&E respectfully requests the CPUC adopt this proposed rate design proposal and require Reform Tariff customers to take service on this default rate, unless and until other more cost-based rates are available.

Current residential rate design is misaligned with cost causation principles; residential rates recover nearly all costs in volumetric (kWh) rates, regardless of whether those costs are fixed. SDG&E proposes a new, more cost-based, non-tiered TOU rate ("TOU-DER") as the default rate for residential Reform Tariff customers. This rate would also be available with no eligibility restrictions on an opt-in basis to other, non-Reform Tariff customers. A more cost-based rate will ensure that future Reform Tariff customers receive more appropriate price signals and will allow for a corresponding lower Grid Benefits Charge. Additionally, more accurate price signals will help customers achieve greater long-term financial certainty when they make their energy decisions.

SDG&E's proposed rate includes a $24.10/month customer charge and non-tiered, cost-based volumetric TOU differentials, using SDG&E's current effective standard TOU periods.[182] Cost-based TOU differentials will provide participating customers with appropriate price signals during on-peak periods and encourage adoption of paired storage devices (batteries), and a higher fixed customer charge will lower the necessary GBC assessed on solar system size. A non-tiered TOU rate will ensure that Reform Tariff customers do not shift the cost of the baseline credit to non-participating customers, and has the potential to encourage electrification, as with the proposed default rate there is no point in their monthly consumption at which their rate suddenly increases to a higher tier.

While SDG&E is proposing a default rate for future Reform Tariff customers, SDG&E reserves the right to open other more cost-based rate schedules to these customers in the future. SDG&E proposes to restrict Reform Tariff customers to the default proposed rate or Value of Distributed Energy (VODE) tariff described below, except as discussed in the following paragraph, until other, more cost-based rates are approved by the CPUC.[183]

SDG&E does not offer any existing residential rates that would be appropriate for the residential default Reform Tariff rate. SDG&E has one other opt-in more-cost-based residential rate that has a $16 fixed charge. This rate, Schedule EV-TOU-5, is only available to customers with electric vehicles (EVs) and is designed to specially incentivize EV charging during certain hours. If a Reform Tariff customer also had an EV and met the eligibility requirements for EV-TOU-5, that customer could choose to take service on EV-TOU-5, but the design of this rate is such that it would not be appropriate

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[182] Adopted in D.17-08-030. *See* pages 25-26.

[183] For example, SDG&E was ordered in D.20-03-003 to file an application for an optional residential non-tiered TOU rate with a fixed charge that customers with certain electrification technology eligibility restrictions. SDG&E may propose to allow Reformed Tariff customers to also take service on this rate. Additionally, real-time-pricing (RTP) was addressed in SDG&E's pending GRC Phase 2 Application 19-03-002. In the event the Commission adopts a RTP rate available to residential customers, SDG&E may propose that Reform Tariff customers be able to take service on this more dynamic, cost-based rate.

for customers without EVs.[184] Table IV-17 below shows SDG&E's proposed illustrative residential Reform Tariff default rate structure:

Table IV-17
SDG&E Proposed Illustrative Total Residential DG-ST Default Rate
("TOU-DER")

Description	Unit	Total Rate
Customer Charge	$/month	$24.10
Energy Charges:		
Summer:		
On-Peak	$/kWh	0.54
Off-Peak	$/kWh	0.28
Super Off-Peak	$/kWh	0.22
Winter:		
On-Peak	$/kWh	0.24
Off-Peak	$/kWh	0.23
Super Off-Peak	$/kWh	0.22
Illustrative TOU Differentials:		
Summer - On: Super Off-Peak		2.5 : 1
Winter - On: Super Off-Peak		1.1 : 1

c) <u>TOU-DER Distribution Rate Design</u>

SDG&E's proposed customer charge recovers the customer-specific costs of providing electric service that do not vary with customer usage from residential Reform Tariff customers. These marginal customer costs include the cost of meters, service drop, final line transformer, billing and payment, customer call center, and other revenue cycle services costs, and are fully scaled to current effective revenue requirements.[185]

The fixed charge in TOU-DER would not be incremental; recovery of costs through this fixed customer charge will result in a compensating reduction in the current rate structure's

[184] Because customers taking service on EV-TOU-5 would have a different fixed charge than the one proposed in TOU-DER, they would also have a different Grid Benefits Charge.

[185] Calculated as of June 1, 2021.

artificially inflated volumetric distribution rates. A cost-based fixed charge will help move toward a more equitable system and balanced rate structure, as well as encourage electrification through lower volumetric charges.

In Table IV-18 below, SDG&E presents illustrative TOU-DER distribution rates. For comparison purposes only, SDG&E also shows the distribution rates for its default residential TOU rate, Schedule TOU-DR1. TOU-DR1 is a tiered TOU rate with a baseline credit and a minimum bill. Addition of SDG&E's proposed fixed customer charge in TOU-DER will effectively allow for reduction of the volumetric rate by approximately $0.06/kWh, resulting in an average total volumetric rate of approximately $0.25/kWh.

Table IV-18
Proposed Illustrative TOU-DER Distribution Rates
Compared to Default Residential Distribution Rates

Distribution Charges	Unit	Proposed Illustrative TOU-DER Distribution Rates	Comparison Purposes Only: SDG&E Default Residential Rate Distribution Rates
Customer Charge	$/month	$24.10	$0.00
Volumetric Energy Charges:			
Summer:			
On-Peak	$/kWh	0.06330	0.12180
Off-Peak	$/kWh	0.06330	0.12190
Super Off-Peak	$/kWh	0.06330	0.12180
Winter:			
On-Peak	$/kWh	0.06330	0.12180
Off-Peak	$/kWh	0.06330	0.12190
Super Off-Peak	$/kWh	0.06330	0.12180
Minimum Bill	$/day	0.000	0.345

d) <u>TOU-DER Commodity Rate Design</u>

SDG&E's default residential Reform Tariff rate will be based on marginal cost-based commodity rate TOU differentials, based on the seasonal definitions adopted in D.17-08-030.[186] SDG&E is not proposing a fixed differential. Table IV-19 presents illustrative commodity rates for TOU-DER.

[186] SDG&E's defined Summer months are June-October, Winter months are November-May.

Table IV-19
Proposed Illustrative TOU-DER Commodity Rates

Commodity Charges	Unit	Proposed Illustrative TOU-DER Commodity Rates
Energy Charges:		
Summer:		
On-Peak	$/kWh	0.38718
Off-Peak	$/kWh	0.12423
Super Off-Peak	$/kWh	0.06346
Winter:		
On-Peak	$/kWh	0.08434
Off-Peak	$/kWh	0.07487
Super Off-Peak	$/kWh	0.06436
Illustrative TOU Differentials:		
Summer - On: Super Off-Peak		6.1:1
Winter - On: Super Off-Peak		1.3:1

3. <u>SCE</u>

a) <u>SCE's Current Residential Rates consist of the following rate components</u>

SCE's residential rates consist of:

Generation-Related*: Applicable to Bundled Customers*

- Bundled Generation – Charges for energy provided by SCE to bundled customers. Includes costs associated with electricity fuel and purchase power from both utility-owned generation and third-party power purchase agreements. Includes the Department of Water Resources Credit (DWR Credit) and demand response program costs.
- Ongoing Competition Transition Charges (CTC) – Embedded in the bundled generation rate, CTC recovers the above-market costs of pre-restructuring resources such as eligible QFs and is the same for all applicable customers in each respective class.

Delivery-Related: Applicable to Bundled and Unbundled Customers

- Transmission – charge for the delivery of high-voltage electricity from power plants to distribution points near customers' homes.
- Distribution – charge to distribute power to customers. It includes power lines, poles, transformers, repair crews and emergency services. Distribution costs are recovered through a flat grid-related component and time-variant peak-related component.
- Public Purpose Programs (PPP) – charge for the costs of certain state-mandated programs (such as income-qualified and energy efficiency programs).
- Nuclear Decommissioning Charge (NDC) – charge for the retirement of nuclear power plants.
- New System Generation Charge (NSGC) – charge for the costs associated with generation power supplier to support distribution greed service that the CPUC has determined should be recovered from all benefiting customers.
- Conservation Incentive Adjustment (CIA) – the pricing mechanism used in tiered rate structures that adjusts tiered rate levels to reflect an increase in pricing, from the lower to upper tiers, with the purpose of incentivize energy conservation.
- California Wildfire Fund Non-bypassable Charge (WF-NBC) – charge for partially funding a source of relief money to pay or reimburse eligible wildfire-related claims.

Cost Responsibility Surcharge (CRS): Applicable to Unbundled Customers

- The CTC and PCIA are recovered from unbundled customers through the CRS tariffs. The CRS also includes the Wildfire Fund NBC, which is not reflected in the delivery charges on unbundled customer bills.

Like the other utilities, SCE's residential cost recovery is almost entirely through volumetric rates. The only exceptions to volumetric cost recovery is a nominal customer charge of approximately $0.94 per-month and a minimum bill of $10 per-month. The ability for current NEM 1.0 and 2.0 customers to entirely offset the minimum bill with net surplus compensation credits is also true for SCE.

The Commission should adopt SCE's TOU-D-PRIME ("PRIME") rate as the default rate option for SCE's residential Reform Tariff customers. PRIME is SCE's technology agnostic electrification rate to encourage the adoption of new GHG reducing technologies by reflecting cost-based price signals to discourage usage during high GHG production periods and encourage usage in periods where there are fewer GHG producing resources online. The cost-based nature of PRIME allows customers to affordably adopt new building electrification (BE) and transportation electrification (TE) technologies in advance of solar adoption. This path to adoption can result in more effective rightsizing of solar systems thus making the solar project itself more cost effective and also reducing the cost shift that would otherwise result from an oversized system. PRIME's cost-based nature inherently reduces the cost shift associated with solar adoption through more appropriate time-variant pricing and a cost based fully scaled customer charge, which in turn reduces the level of Grid Benefit Charge used in the successor tariff.

b) <u>SCE's Reform Tariff Default Residential Rate Proposal</u>

SCE proposes to use its existing PRIME rate as the default rate for Reform Tariff residential customers. PRIME is a non-tiered TOU rate with a fixed customer charge that was approved in its 2018 General Rate Case ("GRC") Phase 2.[187] Introduced as a "whole house" option for residential EV charging, PRIME's structure and pricing also make this rate option suitable for broader electrification applications to include heat pumps, heat pump water heaters, and paired storage. The use of PRIME as the default Reform Tariff will encourage solar customers to also adopt paired storage by offering steeper price differentials between the highest and lowest-cost periods. PRIME's inclusion of a meaningful customer charge helps reduce pricing of the energy rates, and the level of Grid Benefits

[187] D.18-11-027.

Charge necessary to achieve a given reduction in the cost shift by reflecting the lower energy rates in development of the GBC. In the future, Reform Tariff customers may select alternative residential TOU rate options, if other more cost-based TOU or real-time-pricing rate schedules with fixed charges become available.

The current PRIME rate reflects a 12 dollar-per-month customer charge to recover costs associated with connecting the customer to the distribution grid[188] including customer service, metering, and billing. SCE proposes to update the customer charge in the periodic consolidated rate adjustments and in GRC Phase 2 proceedings to align with the most current revenue requirements and marginal cost studies.

PRIME's time of use periods were established in SCE's 2018 GRC Phase 2 proceeding. The lowest price periods are from 8 a.m. – 4 p.m. and 9 p.m. – 8 a.m., with the lowest-cost Super Off-Peak period in the winter season (October through May) from 8 a.m. – 4 p.m. The summer rates have two periods during a day with 4 p.m. – 9 p.m. priced at on-peak during weekdays and priced at mid-peak during weekends. Other hours outside of the summer 4 p.m. – 9 p.m. period are priced at off-peak.

The underlying marginal costs associated with PRIME were also established in the 2018 GRC Phase 2, where distribution marginal costs were updated to reflect the two primary functions of the distribution system. SCE functionalized distribution costs into the following components: (1) a peak capacity function to meet time-variant peak customer demand; and (2) a grid or network function that enables the bi-directional flow of energy to and from customers. In taking this approach, SCE recognized the increased adoption of DER technologies to meet California's climate goals would result in third party and customer sited applications that would change the drivers of distribution related costs. A single non-coincident peak demand driver, for example, does not capture the diurnal pattern or bi-directional nature of circuit loading caused by the cyclical DERs powered by the sun for SCE. This pattern was similarly captured in generation marginal costs through the addition

[188] These costs, determined in SCE's 2018 GRC Phase 2, include costs associated with the final line transformer, final line drop, and metering.

of a flex capacity cost component (added to the traditional generation energy and peak capacity components) driven by the ramp in generation resources experiences as the sun recedes. Collectively, the new TOU periods and underlying marginal cost structure provide for cost-based pricing that can drive solar installations in a direction to deliver the most benefit to the grid while reducing the non-participant cost burden.

In SCE's open 2021 GRC Phase 2 case (A.20-10-012), SCE discusses how PRIME was originally designed for residential households with a battery-electric or plug-in hybrid vehicle, BTM battery or electric heat pumps by using a basic fixed charge to reduce the volumetric kWh price levels closer to marginal cost. In the open GRC Phase 2 application, SCE proposes to remove PRIME's eligibility and related attestation requirements for specific clean energy technologies, as the limitations represent an unnecessary barrier to participation, which excludes or limits other technologies, including rooftop solar.

SCE's PRIME rate levels as of June 2021 are shown in Table IV-20 below.

Table IV-20
SCE's TOU-D-PRIME Rate – Non-CARE

Charge	Unit	Total Rate
Customer Charge	$/month	$12.02
Energy Charges:		
Summer:		
On-Peak	$/kWh	0.45
Mid-Peak	$/kWh	0.33
Off-Peak	$/kWh	0.17
Winter:		
Mid-Peak	$/kWh	0.41
Off-Peak	$/kWh	0.17
Super-Off-Peak	$/kWh	0.17
TOU Differentials		
Summer On: Off-Peak		2.6:1
Winter Mid: SOF-Peak		2.5:1

C. Export Compensation Rates

1. Summary

We propose that exports from Reform Tariff customer-generators be compensated at an approximation of avoided cost, with time-of-export (TOE) periods that match the TOU periods of the underlying tariff. Illustrative export compensation rates (ECR) for each utility are shown in Table IV-21 - Table IV-23, using the most recent proposed version of the Avoided Cost Calculator (2021 ACC).[189] The approach of compensating exports according to their actual value is common among jurisdictions which have replaced net metering, including several California Municipal Utilities[190] and

[189] *See* May 21, 2021 E-mail Ruling. Although the 2021 ACC is still in draft form, it will be final by the time the Commission issues its proposed decision in this proceeding. All calculations in this testimony that include the ACC utilize the 2021 version of the ACC. Draft Resolution E-5150 was released on May 3, 2021. The draft resolution is on the June 24, 2021 Commission meeting agenda.

[190] Alameda Municipal Power, Anaheim Public Utilities, City of Palo Alto Utilities, City of Roseville, Imperial Irrigation District, and Modesto Irrigation District have all transitioned to compensating exports at an avoided cost rate. On May 18, 2021, Sacramento Municipal Utilities District submitted its 2021-2022 Rate Proposal, which will pay solar paired storage customers utility avoided costs of $0.074/kWh.

two small multi-jurisdictional utilities subject to CPUC regulation.[191] This section describes the methodology and rationale for how these export compensation rates are determined.

Table IV-21
PG&E Seasonal Export Compensation Rates by TOE

TOE Period	Unit	Residential (E-DER)	Non-Residential (B1, B10, B19, B20)	Agricultural
Volumetric Energy Rates:				
Summer:				
On-Peak	$/kWh	0.113	0.132	0.160
Part-Peak	$/kWh	0.070	0.068	N/A
Off-Peak	$/kWh	0.051	0.048	0.058
Winter:				
On-Peak	$/kWh	0.058	0.063	0.089
Part-Peak	$/kWh	0.037	N/A	N/A
Off-Peak	$/kWh	0.026	0.035	0.030
Super Off-Peak	$/kWh	N/A	0.017	N/A

Table IV-22
SDG&E Seasonal Export Compensation Rates by TOE

TOE Period	Unit	SDG&E Illustrative Proposed Export Compensation
Volumetric Energy Rates:		
Summer:		
On-Peak	$/kWh	0.114
Off-Peak	$/kWh	0.058
Super Off-Peak	$/kWh	0.060
Winter:		
On-Peak	$/kWh	0.059
Off-Peak	$/kWh	0.029
Super Off-Peak	$/kWh	0.028
TOE Differentials		
Summer - On: Super Off-Peak		1.9 : 1
Winter - On: Super Off-Peak		2.1 : 1

[191] CPUC D.20-01-007 adopted PacifiCorp's Net Billing Proposal. D.20-01-008 adopted Bear Valley Electric Service Division's (BVES) proposed net billing tariff, which compensates exports at BVES's avoided costs.

Table IV-23
SCE Seasonal Export Compensation Rates by TOE

TOE Period	**Unit**	**SCE Illustrative Proposed Export Compensation**
Volumetric Energy Rates:		
Summer:		
On-Peak	$/kWh	0.166
Mid-Peak	$/kWh	0.140
Off-Peak	$/kWh	0.063
Winter:		
Mid-Peak	$/kWh	0.050
Off-Peak	$/kWh	0.061
Super Off-Peak	$/kWh	0.034
TOE Differentials		
Summer - On: Off-Peak		2.6 : 1
Winter - Mid: Super Off-Peak		1.5 : 1

2. <u>Use of the Avoided Cost Calculator</u>

The Avoided Cost Calculator (ACC) is an important tool for evaluating the cost-effectiveness of demand-side resources. However, it was not designed to directly inform rate design. The ACC is discussed in more detail in Chapter 3. We propose to leverage the ACC's analysis of the value of DERs to inform the level of the ECR, subject to other considerations to avoid unintended consequences. In many cases, the ACC does not directly align with marginal costs as filed in respective each utility's GRC Phase 2 applications.

The ACC produces a forecast of values for each hour of the year. To aggregate these 8,760 hourly values into ECR rates, we propose weighting the 1-year levelized ACC avoided costs by its metered customers' export profile. This ensures that the compensation provided to Reform Tariff customers for their exported energy will match the value of that energy to the grid. We are not proposing fixed differentials for TOE compensation. Using recorded exports instead of a production profile of a solar generator ensures that customers are properly compensated for when exports occur.

Currently, exports disproportionately occur during times when the system is more likely to have excess renewables. If in the future customers use battery storage to avoid exporting at less valuable times and shift that energy production to more valuable times, the proposed approach would result in the ECRs adjusting accordingly.

Further, weighting ECR by customer exports is a better measure than simply averaging ACC hourly values by TOE period, because it ensures that customers are compensated fairly during each TOU period. For example, customers will be paid a fair rate for their 4 PM – 5 PM exports, rather than paid what they would be worth over the entire on-peak period from 4 PM – 9 PM. Within the ACC, the utilities see higher cost hours in the latter half of the on-peak period (approximately 6 PM – 9 PM) than at the beginning of the on-peak period (4 PM – approximately 6 PM). If customers were compensated at the average ACC values from 4 PM – 9 PM, we would be overpaying for exports at the beginning of the on-peak period. An example of this is seen in Table IV-24 below, using one day's on-peak period in SDG&E's service territory.

Table IV-24
2021 ACC: SDG&E Climate Zone 7 – On-Peak Period, August 27, 2022

Hour Ending	$/kWh	Export Profile
17	$0.055	5.697%
18	$0.039	2.131%
19	$0.430	0.279%
20	$0.110	0.053%
21	$0.074	0.053%

Taking a simple average of the on-peak period for this day would result in an illustrative average on-peak price of $0.142/kWh. However, weighting by the export profile results in an illustrative on-peak price of $0.01/kWh. Using this methodology ensures that DG-ST customers are appropriately compensated for their exports, and not overpaid at 8 PM – 9 PM prices for 4 PM – 5 PM exports. A comparison of average, export profile weighted, and generation profile weighted ECR is presented below for PG&E in Table IV-25.

Table IV-25
2021 ACC PG&E 1-Year Levelized 2022 Values by TOE and Season

2021 ACC - Illustrative 1 Year Values ($/kWh)			
Time of Export Period	Proposed - Export Weighted	Illustrative Comparison - Generation Weighted	Illustrative Comparison - Simple Average
Summer:			
On-Peak	0.113	0.126	0.271
Part-Peak	0.070	0.069	0.098
Off-Peak	0.051	0.051	0.040
Winter:			
On-Peak	0.058	0.063	0.077
Part-Peak	0.037	0.043	0.046
Off-Peak	0.026	0.029	0.034
Average Export Compensation	0.042	0.044	0.052

This approach ensures that the ECR is set in a technology-neutral manner. The ECR tables above are currently weighted by customer solar exports, as the overwhelming majority of recorded NEM exports are from solar generators. This export profile would be updated annually and would likely change over time as the mix of technologies participating in the successor tariff evolves. For example, as solar paired storage proliferates in the Joint utilities' territories, the paired solar generation can be expected to be stored and shifted to higher retail cost periods, and thus change the ECR over time. Currently, CARE customers receive lower export compensation because they pay a lower retail rate. The Joint utilities' proposal rectifies this imbalance.

3. <u>Other Adjustments</u>

After calculating the ECR as described above, the rates should be capped to be no more than the corresponding retail commodity volumetric rate in each TOE period. At current rates and ACC forecasts, this cap is unlikely to impact most rates but may impact certain rates with significant demand charges that have relatively low volumetric rates in the peak period. This reflects that the ACC was not built as a rate design tool and does not necessarily align with utility marginal costs or rate design methodologies.[192] Ideally, export rates should align as much as possible with utility marginal costs. In the future, we recommend exploring how greater alignment can be achieved between utility marginal costs and the ACC.

Export rates exceeding the retail rate would lead to unintended suboptimal discharge behavior. For example, many behind-the-meter batteries can only discharge at maximum capacity for less than three hours. If customers can minimize their bill by exporting at much as possible for the first few hours of the peak window, that will result in the customers returning to their unmitigated usage in the latter half of the peak period. Per the ACC, the highest cost hours tend to occur in the latter hours of the "standard" 4 PM – 9 PM peak period, as shown in Table IV-24.

4. <u>Bundled vs. Unbundled Customer Treatment</u>

Per Guiding Principle H,[193] the Reform Tariff must consider how unbundled customers would interact with the successor tariff. To address this, the ECR should be split into "commodity" and "system" components. By splitting the ECR into these two general "components", we are ensuring that bundled and unbundled customer indifference is achieved to the extent possible.

The generation commodity portion of the ECR would be paid by the customer's load serving entity (LSE), with the utility's commodity ECR rate being based on the energy, cap-and-trade, and capacity components of the ACC output. Other LSEs would be free to choose what compensation they provide, as they do today.

The system portion of the ECR credit would be from the distribution utility and include all other ACC components, including transmission, distribution, greenhouse gas (GHG) adder, and methane leakage. Note that while the GHG adder and methane leakage components are associated with generation services, they represent values that are not directly monetized in generation rates. To avoid any asymmetry between bundled and unbundled ECRs, it is therefore appropriate for these components to be compensated to all customers.

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[192] To the extent the avoided transmission components require approval from the Federal Energy Regulatory Commission (FERC), the Joint IOUs would seek such approval.

[193] D.21-02-007, OP 1.

It is important to levelize ACC costs over a short period to ensure that Reform Tariff customers are both compensated fairly and to achieve indifference between load-serving entities (LSE) for departing load customers. While is it unlikely the Reform Tariff will be able to achieve perfect customer indifference, using a short-term ACC value will minimize the difference LSEs and the utilities pay to Reform Tariff customers.

Our approach is not only simpler, it is more fair to both participating and non-participating customers. Using a 1-year levelized value will help to ensure that the utilities do not overpay for customer-sited generation, which minimizes the risk of shifting the cost of these overpayments to non-participating customers.

5. <u>Update Cadence</u>

The Utilities propose to update the ECR annually via a Tier 1 advice letter following the adoption of the annual ACC update. This would use the ACC's forecast of year ahead values to inform the export compensation. This update frequency would ensure the ECR remains consistent with underlying costs and CPUC policies. The illustrative ECRs above, are from the 2021 version of the ACC, forecasting year 2022 avoided costs, levelized one year. By the time the Reform Tariff is implemented, the 2022 version of the ACC may be available, so the above rates should only be taken as illustrative.

We recognize that a fixed ECR based on a long term, levelized forecast from the 2020 ACC may be preferable to the solar industry. Such a structure represents a significant shift in risk from generators to non-participating customers. California has an unfortunate history of generators being paid based on long-term forecasts that turned out to result in out-of-market payments. Adopting an ECR that is updated annually will ensure that Reform Tariff customer-generators are compensated fairly and that non-participating customers do not overpay (or, potentially, underpay) for their generation.

Indeed, the significant shift in the long-term value of solar forecasted by the 2021 ACC versus the 2020 ACC, while near term values remain similar, demonstrates the flaw of basing compensation on a long-term forecast. Long term forecasts are inherently uncertain, and basing compensation on a long-term forecast value inevitably will result in inaccurate compensation.

For example, the 2020 ACC forecasted value of solar escalated significantly after 2030, while the 2021 ACC forecasted value of solar decreases through 2030, and then only escalates slightly thereafter. If a long term levelized value were based on the high forecast, which turned out to be an overestimate, non-participants would pay a significant premium. Likewise, if a long term levelized value were based on the low forecast, which turned out to be an underestimate, participants would not receive the compensation they deserve.

The Commission recently adopted processes by which to update net billing export compensation rates annually for other utilities subject to CPUC jurisdiction. In D.20-01-007, the Commission found that "an export credit with a fixed value for more than one year may not accurately reflect the values underlying the credit" and adopted PacifiCorp's proposal to update its export compensation annually through a Tier 1 Advice Letter process.[194] Additionally, in D.20-01-008, the Commission adopted a Tier 1 Advice Letter process to update Bear Valley Electric Service's net billing export credit on an annual basis.[195] We respectfully request that the Commission adopt a process by which to update the ECR annually, based on the most recent version of the ACC.

D. <u>Netting Interval / True Up</u>

We are proposing a net billing structure, where all energy delivered to the customer on meter Channel 1/Channel A is billed at the retail rate, and all energy exported to the grid on meter Channel 2/Channel B is compensated at the ECR discussed above, except that customers will only be compensated at the ECR for exports up to the extent they import. This proposal incentivizes Reform Tariff customers to size their systems appropriately for load, better aligns prices with cost-causation, and encourages adoption of solar paired storage over standalone solar by improving price signals to shift load out of high-demand periods. Specifically, we are proposing:

- Export compensation within a TOU/TOE period can only offset grid consumption during the same TOU/TOE period;

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[194] D.20-01-007, at 17-18. COL 1 also states: *This decision should not be regarded as precedent for any future Commission decision that may address the issue of compensation structures for distributed renewable energy systems.*

[195] D.20-01-008, OP 2.

- Exports exceeding the kWh imported within a TOU period will be compensated at the net surplus compensation (NSC) rate;[196]
- Value from NSC can be carried forward from prior billing cycles. The dollar value of those credits would be carried over for up to one year (*i.e.*, interconnection anniversary) to avoid the issuance of monthly customer refunds;[197] and
- Customers will be trued-up monthly.

1. NEM Customers Today Do Not Receive Appropriate Price Signals

Today, NEM customers are credited the retail rate for each kWh they export to the grid. When they are net exporters, customers can carry forward ("bank") credits to offset any future grid consumption nettable charges from month to month and across TOU periods until their annual true-up. Customers are "trued-up" annually on their interconnection anniversary, and any net exported kWh for the year is paid out at the Net Surplus Compensation rate as a cash payment.

Under current netting policy, NEM customers do not receive appropriate price signals. Those NEM customers who take service on a TOU rate can use their generation from the middle of the day (typically an off-peak or mid-peak time period) and offset their consumption in the high-cost evening hours, when the sun is not shining and solar customers are not generating energy. In general, this arrangement allows customers to use their bank of credits to offset nettable charges from consumption at a later date, creating a mismatch of value. For example, customers who over-generate and are net exporters in March and April, when generation costs are relatively low, are able to carry those credits forward and potentially offset consumption in August and September, when the cost of energy is relatively high. Allowing this policy to continue in the Reform Tariff would disincentivize customers from shifting load out of the on-peak period.

As California moves toward its climate and GHG goals, it is increasingly important for the Commission to think about the value of customer-sited generation temporally. During the day, when there is already excess solar generation on the grid, incremental solar exports do not provide significant

[196] We are not proposing a change to the current calculation of net surplus compensation.

[197] As an example, if a billing period ends on 6/30 and a customer has one unused kWh valued at the ECR of $0.15, it would convert to the prevailing NSC value on 7/1.

added value in the same way exports would during the peak evening hours. As discussed in Chapter 1, additional distributed solar is resulting in increasing amounts of curtailed utility-scale solar in California. Therefore, it does not make sense to allow netting of mid-day exports against evening grid consumption or other hours, allowing Reform Tariff customers to use the grid as a free battery – the way current NEM customers are able to. In most cases these clean exports are not stored, and the energy they import during the evening hours is not the same renewable energy they exported. As seen below in Figure IV-30, the marginal emissions intensity of this kWh exchange is not 1-for-1; net zero energy (offsetting 100% of annual load with onsite generation) is not the same as net zero carbon.

Figure IV-30
2021 California Hourly Marginal Emissions Intensity (MT CO_2/MWh)[198]

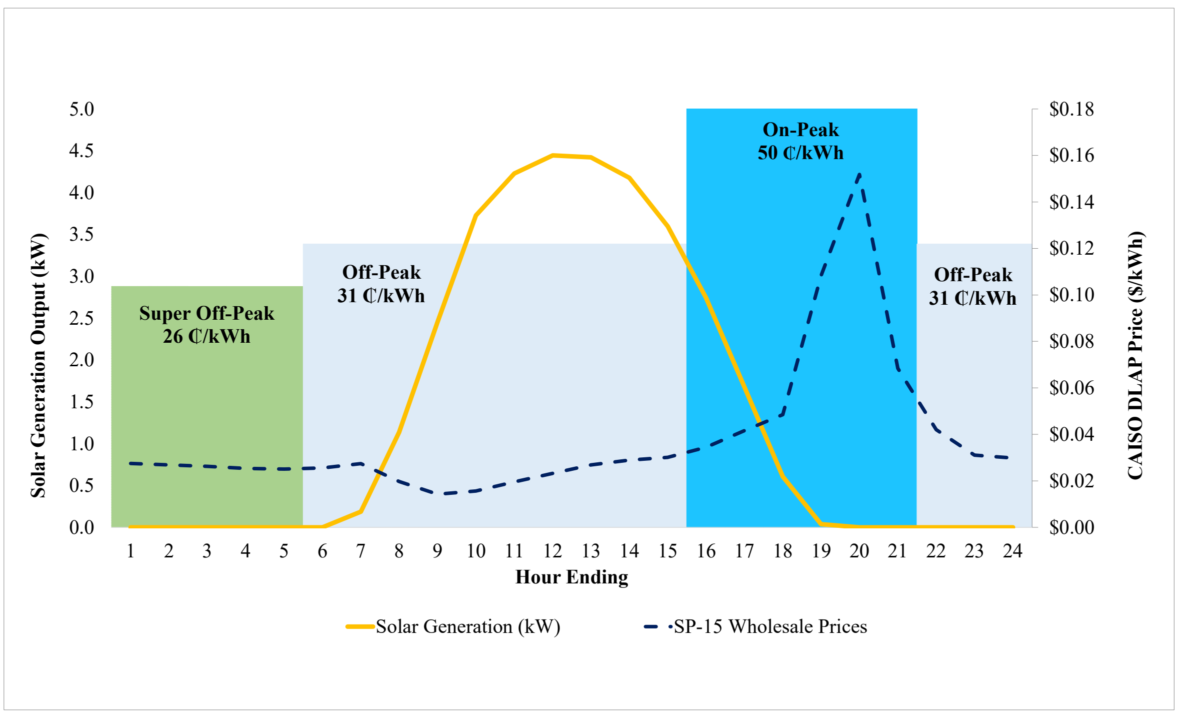
	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0.41	0.39	0.32	0.17	0.17	0.21	0.40	0.42	0.43	0.42	0.41	0.42
1	0.41	0.40	0.33	0.18	0.18	0.23	0.41	0.43	0.43	0.42	0.42	0.42
2	0.41	0.39	0.33	0.18	0.19	0.23	0.41	0.43	0.43	0.42	0.42	0.42
3	0.40	0.39	0.33	0.17	0.18	0.23	0.41	0.43	0.43	0.42	0.42	0.42
4	0.40	0.37	0.31	0.14	0.16	0.22	0.40	0.43	0.43	0.42	0.41	0.41
5	0.38	0.36	0.27	0.12	0.14	0.19	0.40	0.41	0.42	0.40	0.40	0.41
6	0.35	0.31	0.25	0.12	0.13	0.15	0.39	0.41	0.41	0.39	0.37	0.38
7	0.35	0.28	0.27	0.13	0.14	0.15	0.38	0.40	0.41	0.40	0.37	0.38
8	0.31	0.23	0.18	0.11	0.11	0.12	0.28	0.35	0.35	0.33	0.28	0.33
9	0.23	0.14	0.12	0.09	[illegible]	0.11	0.21	0.29	0.30	0.23	0.17	0.22
10	0.20	0.11	0.10	[illegible]	[illegible]	[illegible]	0.17	0.24	0.24	0.18	0.16	0.20
11	0.16	0.11	0.10	[illegible]	[illegible]	[illegible]	0.15	0.22	0.22	0.16	0.15	0.19
12	0.16	0.11	0.10	[illegible]	[illegible]	[illegible]	0.14	0.20	0.22	0.17	0.15	0.19
13	0.19	0.12	0.10	[illegible]	[illegible]	[illegible]	0.14	0.18	0.20	0.17	0.17	0.21
14	0.23	0.13	0.10	[illegible]	[illegible]	[illegible]	0.14	0.16	0.24	0.18	0.22	0.25
15	0.31	0.19	0.12	[illegible]	[illegible]	0.09	0.14	0.16	0.26	0.24	0.35	0.37
16	0.35	0.31	0.17	0.10	0.09	0.09	0.14	0.16	0.27	0.29	0.35	0.35
17	0.32	0.26	0.21	0.11	0.10	0.10	0.14	0.17	0.31	0.28	0.28	0.32
18	0.31	0.24	0.16	0.10	0.10	0.11	0.15	0.22	0.32	0.29	0.28	0.32
19	0.32	0.24	0.17	0.11	0.11	0.12	0.21	0.31	0.35	0.33	0.30	0.32
20	0.34	0.27	0.19	0.11	0.11	0.13	0.30	0.36	0.37	0.35	0.35	0.34
21	0.35	0.31	0.25	0.12	0.12	0.13	0.36	0.38	0.39	0.39	0.37	0.36
22	0.38	0.35	0.29	0.13	0.12	0.14	0.38	0.40	0.41	0.41	0.39	0.39
23	0.40	0.38	0.32	0.14	0.15	0.16	0.39	0.41	0.42	0.42	0.41	0.40

An additional illustration of this contrary relationship in SDG&E's service territory is seen below in Figure IV-31, showing solar generation juxtaposed with CAISO wholesale prices on

198 Source: CEC Staff Draft 2021 Hourly Marginal Emissions, accessed at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442469347.

August 1, 2020, and retail rates that were effective at the time. Solar generation is not aligned with either the utilities' standard on-peak period of 4 PM – 9 PM or wholesale prices. Allowing export credits in the non-peak periods to offset grid consumption during the on-peak period would be misaligned with state policy and would not incentivize customer load flexibility nearly to the same extent as our proposal. The same principle extends to allowing banking of cross-month export compensation credits. Exports in April of 2020 did nothing to offset grid consumption during the hot summer months or rolling outages of 2020; in order to support state policy goals, Reform Tariff customers should not be able to bank export credits as current NEM customers do.

Figure IV-31
Solar Output vs. Market Price Comparison
August 1, 2020



- Retail prices shown for SDG&E default residential rate, TOU-DR1, summer weekdays. Rates effective 7/1/2020 and do not include baseline credit adjustment.
- Hourly generation profile for August based on PV Watts 6.5 kW-dc system in San Diego.

2. <u>TOU Netting Encourages Customer Behavior that Benefits the Grid</u>

We propose that export compensation credits from one TOU period may not offset grid consumption from a different TOU period. Additionally, after a customer nets out all grid consumption within a TOU period, any excess exported generation will be compensated at the NSC rate. Under this proposal, customers will be credited for every kWh exported to the grid, up to the amount of kWh they import from the grid. In other words, customers will not be able to offset kWh produced and exported during low-cost hours (during the mid-day off- or mid-peak hours) against grid consumption during high-cost on-peak hours. This design—where customers cannot be compensated for kWh beyond what they receive from the grid—is necessary to ensure that customers do not receive an inappropriate incentive to oversize their systems, which would occur if the Commission were to adopt an arrangement where customers are compensated for unlimited exports.

This policy will provide better price signals than allowing customers to use over-generation during the day when wholesale market prices are low and the utilities are forced to curtail utility-scale solar generation, to offset their consumption in the evening hours. This tariff feature would provide an additional incentive to adopt paired storage with solar systems, as customers would have an incentive to consume their self-generation onsite.

3. <u>Monthly True-Ups</u>

We propose that customers cannot carry over export credits from one month to subsequent months. The annual true-up cycle is not an effective policy tool and its removal would ensure that credits meant for renewable energy are not being used for grid energy that contains a mix of renewable and fossil fuel sources. Customer export compensation would be aligned with billing cycles, allowing customers to track their system's production and impact on bills with more accuracy.
As described further in Chapter 6, this approach should also enhance consumer protection measures consistent with the Commission's Guiding Principles. Changing the true-up period from an annual period to a monthly period will also reduce unexpectedly high bills that some NEM customers face at the end of their annual true-up period that can surprise and challenge customers financially.

Disallowing carryover of credits over an annual period also has the potential to encourage more reliable demand response. In 2020, customers who had a bank of excess generation credits going into August would have been able to apply those credits to energy pulled from the grid during flex alerts and rolling blackouts initiated by the California Independent System Operator (CAISO). Accumulating credits during the first half of the year that can be applied to subsequent charges reduces the incentive for NEM customers to conserve during periods of high demand, since these excess credits mitigate bill increases the customer would have otherwise seen.

An example of our proposed export compensation TOU netting is presented below in Table IV-26

Table IV-26
Illustrative Export Compensation Monthly True-Up Proposal Example

TOU/TOE Period	Imported kWh	Exported kWh	Compensated at ECR	Net Imports (Exports)	Compensated at NSC
On-Peak	100	25	25	75	n/a
Off-Peak	150	200	150	-50	-50
Super Off-Peak	200	100	100	100	n/a

In the above example, the 50 kWh of generation exported during the Off-Peak period in excess of grid imports during the same period is compensated at the NSC rate, and cannot be counted toward ECR eligible offsets for either On-Peak or Super Off-Peak hours. In other words, a customer can be net zero kWh in each TOU period, but any kWh exports beyond net zero (imports – exports = 0) will be compensated at NSC rates.

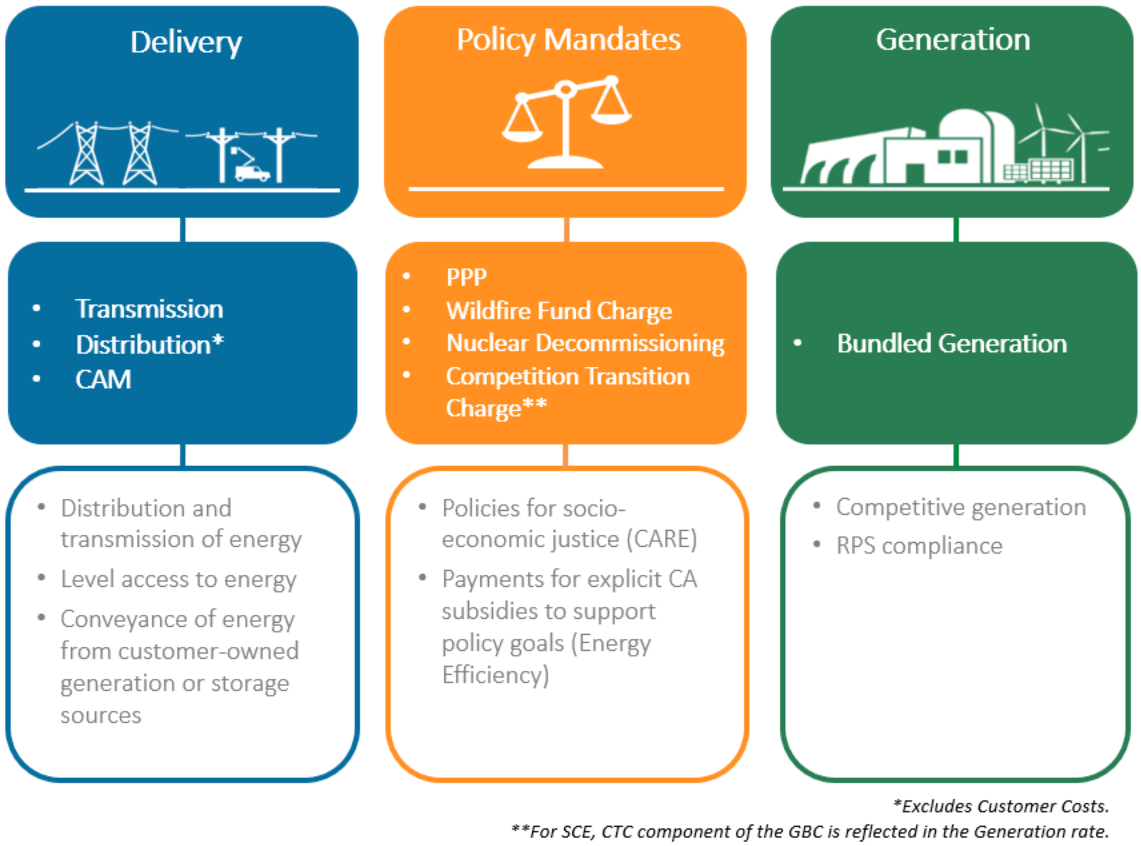
E. <u>Grid Benefits Charge</u>

1. <u>Residential Grid Benefits Charge Overview</u>

Residential customers without solar currently pay for costs of the grid, generation, policy mandates and customer services through volumetric rates. When adopting solar and moving to the current NEM structure, NEM customers are able to avoid paying for those costs with offsetting energy credits priced at the full retail value. To eliminate avoidance of costs that continued to be incurred by those customers, we propose a \$/kW-month Grid Benefits Charge based on a customer's installed solar system size, net of any avoided cost benefits. This charge will vary by utility, and by rate option.
A Grid Benefits Charge is necessary alongside value-based export compensation and default cost-based retail rates because as more customers adopt solar-paired storage systems over standalone solar systems, the amount of self-generation they export will decrease. If the Reform Tariff were only to adopt a

change in export compensation, California would see a significant cost shift from solar-paired storage customers in the future. An illustration of the GBC components is below in Figure IV-32.

Figure IV-32
Grid Benefits Charge Components



A Grid Benefits Charge is essential to ensure that California is adopting a forward-looking tariff that ensures non-participant equity as the standard moves from distributed standalone solar to solar+storage. For example, if a standalone solar NEM customer today exports 50% of their generation to the grid, changing export compensation from retail rates to avoided costs would reduce the cost shift from that customer by approximately 50%. However, solar+storage customers do not export a significant amount of their generation. If a solar+storage customer only exports 20% of their generation compensated at avoided costs, without a Grid Benefits Charge, the potential reduction in cost shift would be limited to that 20%. If the Commission fails to adopt adequate fixed cost recovery, the NEM cost shift will continue to increase at a significant rate, and the Commission may find itself once again reviewing the tariff again in a couple of years. However, at this point the cost shift and upward rate pressure will be even worse.

The majority of NEM customers continue to pull energy from the grid on a daily basis. The Commission has affirmed that customers who depart utility service either in full or in part are responsible for cost responsibility surcharges incurred on their behalf as a utility customer. Even for those customers who only pull energy from the grid intermittently, the Commission has determined that standby charges based on demand are appropriate. If NEM customers were to fully meet their own energy needs and not use any grid energy, they would be most comparable to departed load customers, who are subject to cost responsibility surcharges, including departing load charges. However, currently NEM customers operate in a middle ground that is not subject to charges that would apply to departed load or customers without any form of self-generation despite retaining characteristics of both.

The GBC will ensure that NEM Reform Tariff customers pay for the benefits and services they receive by being connected to the grid.

Distributed generation solar customers use and rely on the grid at all times: when the sun is not shining (at night and during cloudy/rainy days), during peak grid conditions, and during the day in order to export excess generation. Our proposed GBC recovers the portion of distribution, transmission, nonbypassable charges, and generation that current NEM customers avoid by consuming their self-generation onsite, after accounting for avoided costs. Because Reform Tariff customers will also pay the retail rate for any imported energy, the combination of the GBC and retail rate imports ensures that Reform Tariff customers do not shift costs to nonparticipants and make an equitable contribution to grid costs.

The electric distribution system is a network of infrastructure that enables both the historical one-way flow of electricity to the customer's location as well as the two-way flow from solar customer exports. Solar customers use the distribution system daily; this infrastructure is needed to serve energy deliveries and accommodate energy exports. Distribution costs are typically split between customer-related costs (meters, transformers, service drops, and revenue cycle services) and demand-related costs (upstream costs of poles, wires, substations, etc.). As we have proposed to recover customer-related costs through the customer charge component of the default rate, the distribution costs recovered through the proposed GBC are demand-related. However, if the Commission decided not to adopt fixed charges that fully recover customer-related distribution costs from Reform Tariff customers, the GBC should be increase commensurately to ensure equitable cost responsibility from Reform Tariff customers.

Each Utility's Grid Benefits Charges will be based on current effective rates, and the observed estimated average export percentage of that customer class over the previous year. If residential customers export, on average, 60% of their generation as is the case in SDG&E's service territory currently, then the Grid Benefits Charge should recover the costs that are avoided by consuming 40% of self-generation onsite, less any avoided costs. As discussed in Section IV.A.2, we believe that the Reform Tariff should encourage customers to adopt solar-paired storage installations over standalone solar installations, and therefore are proposing to initially set the Grid Benefits Charge for both standalone solar and solar-paired storage installations at the same level. This initial tariff design will create more onsite consumption bill savings for customers who choose to pair their solar system with a battery than those who choose standalone solar systems.

Each Utility's Grid Benefits Charges will be based on current effective rates, and the observed estimated average export percentage of that customer class over the previous year. If residential customers export, on average, 60% of their generation as is the case in SDG&E's service territory currently, then the GBC should recover the costs that are avoided by consuming 40% of self-generation onsite, less any avoided costs. As discussed in Section IV.A.2, we believe that the Reform Tariff should encourage customers to adopt solar+storage installations over standalone solar installations, and therefore are proposing to initially set the Grid Benefits Charge for both standalone solar and solar+ storage installations at the same level. This initial tariff design will create more onsite consumption bill savings for customers who choose to pair their solar system with a battery than those who choose solar+storage systems.

We recognize setting the GBC based on the size of the standalone solar system and each utility's recorded exported generation from existing NEM customers will understate the Grid Benefits

Charge that would be required to eliminate the cost shift from solar-paired storage customers. For example, if the GBC is designed to recover 40% of generation (the portion of standalone solar onsite consumption), and on average, solar-paired storage customers consume 80% of their generation onsite, then the GBC for the solar-paired storage customers would be too low to achieve non-participant indifference. Thus, we acknowledge this approach will need to be refined over time as the cost of storage technology declines and the cost shift from solar-paired storage grows as adoption increases.

The Utilities propose that the issue of providing a single GBC for both standalone solar and solar-paired storage be revisited in either a GRC Phase 2 or Rate Design Window after the implementation of the Reform Tariff. A separate Grid Benefits Charge for standalone solar and solar-paired storage installations should be considered at that time to reflect the different consumption and export behavior of the two groups of customers, particularly as storage costs continue to decline.

2. Residential Cost Components & Calculation of GBC

The Grid Benefits Charge will recover remaining distribution costs, transmission,[199] and remaining bundled rate components, net of relevant avoided costs as established by the ACC tool. We propose that current[200] and future NBCs be included in the Grid Benefits Charge. We acknowledge that certain NBCs are required to be collected "on the basis of usage,"[201] but believe that estimated onsite consumption will satisfy this requirement, similar to how standby departing load customers are currently assessed NBCs based on estimated usage.

a) Distribution

While all customers vary, the utility provides the same traditional services to solar customers as to other customers for all hours when they are not generating, and additional services for accommodating exported energy when solar customers are over-generating during the day. Additionally, because solar generation is intermittent, distribution capacity infrastructure must be able to accommodate all customers' energy and demand needs reliably and safely at a moment's notice.

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[199] Transmission rates are FERC jurisdictional. The utilities will propose this rate design in their respective FERC proceedings pending its adoption by the CPUC.

[200] As defined in the NEM 2.0 tariff.

[201] Public Utilities Code § 381(a).

The utility has to ensure that the grid is able to integrate the variable, fluctuating levels of exported solar generation. The distribution grid both serves like a battery, absorbing excess generation, and as a backup generator, providing energy to solar customers when they have need.

As a rule, distributed solar does not decrease the need for the utility to invest in distribution infrastructure. It is possible that in limited, very localized instances, distributed solar could reduce the need for distribution capacity expansions, but this is a far cry from being the rule of thumb. Additionally, many distribution infrastructure investments are related to safety and mitigating wildfire risks. All customers, regardless of whether they have rooftop solar, benefit from a safe grid. Reform Tariff customers should not be able to shift the cost of safety improvements to non-participating customers, as NEM customers do today.

b) <u>Transmission</u>

After adopting solar, customers continue to rely on the transmission grid. Energy transmitted to solar customers during the times when they are not self-consuming often travels long distances through transmission lines. Because NEM customers still import from and export to the grid, they use the transmission system every day, and therefore should fairly contribute to transmission cost recovery.

Transmission project costs are not solely based on capacity needs. There are a variety of non-demand driven reasons why transmission projects are built, including supporting public policy requirements or goals (e.g. Renewable Portfolio Standard Requirements), building facilities to reduce local capacity requirements (LCR) or reduce congestion, building facilities necessary for safety, grid control, visibility, and measurement enhancements, as well as fire hardening and aging infrastructure replacement. Because these projects benefit all customers, including NEM customers, all customers should contribute to paying for their costs.

c) <u>Policy Mandates & NBCs</u>

Policy mandates include costs of programs and legislative mandates, including but not limited to funds for income-qualified programs, energy efficiency programs, and nuclear decommissioning. This portion of the proposed GBC includes what are currently referred to as "non-bypassable charges" in the NEM 2.0 tariff.[202] In order for NEM Reform Tariff customers to contribute the same equitable amount to these programs as non-participants, they must be included in the GBC. Policy costs are largely fixed budgets, and therefore should be collected equally from all customers.

d) Generation

The final piece of the proposed GBC is generation. The fixed costs of generation facilities and contracts should be recovered equally from all bundled customers, as well as legacy costs from unbundled customers. To the extent that avoided costs do not equal current commodity costs, Reform Tariff customers should contribute to that cost recovery.

3. Illustrative GBC Calculation

To calculate the GBC, we calculate estimated annual kWh generation from 1 kW-AC of nameplate capacity by utility. This production is estimated using the capacity factor from the Verdant NEM 2.0 Lookback Study. The calculation multiplies the production by retail rates, less any avoided costs per the 2021 ACC, using 1-year levelized values, and converts this to a monthly charge. The monthly charge is then adjusted to only recover the percentage of generation that the class consumes on site, on average.

A simplified illustrative Grid Benefits Charge for SDG&E is displayed below in Table IV-27, on a total rate basis, not broken down by rate component. Total proposed GBCs are net of any avoided cost benefits.

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[202] For example, SDG&E's policy costs also include Local Generation Charge (LGC) and FERC Reliability Services (RS).

Table IV-27
SDG&E Illustrative Total Proposed Default GBC Calculation

Description	Unit	Calculation	Reference
Total Average Retail Rate (Proposed TOU-DER)*	$/kWh	0.25443	**A**
Less Avoided Costs	$/kWh	(0.04663)	**B**
Net Retail Rate	$/kWh	0.20780	**C = A - B**
Nameplate Capacity	kW-AC	1.0	**D**
Hours per Year		8,760	**E**
Capacity Factor (AC Rating)**		23.16%	**F**
GBC/Year (unadjusted)	$/kW-AC	$422.67	**G = C * D * E * F**
GBC/Month (unadjusted)	$/kW-AC	$35.14	**H = G / 12**
Residential Percent of Onsite Consumption		40%	**I**
Total Proposed Residential Default GBC	$/kW-AC	$14.06	**J = H * I**

* While only the total average rate is shown here for illustrative purposes, each rate component is broken out and calculated separately.

** kW-DC capacity factors from NEM 2.0 Verdant Lookback Study converted to AC.

Using these illustrative charges, if a customer installs a 5 kW-AC solar system, in SDG&E's service territory that customer will pay: 5 kW x $14.06/month = $70.28/month Grid Benefits Charge. If a customer adopts a 5 kW-AC solar-paired storage system paired with battery storage, that customers would also the same charge.

Table IV-28
Illustrative Residential GBC with Default Cost-Based Rate

Utility	Unit	Illustrative GBC
PG&E	$/kW-AC	$14.13
SDG&E	$/kW-AC	$14.06
SCE	$/kW-AC	$10.24

4. Grid Benefits Charge without Default Cost-Based Rate Adoption

The design of our Grid Benefits Charges is based on the assumption that our proposed cost-based rates are adopted as the default rates for Reform Tariff customers. As discussed in Section IV.B, a more cost-based rate with a fixed charge allows for design of a lower Grid Benefits Charge. However, if the Commission does not adopt our proposal for a more cost-based default rate, the required GBC to achieve non-participant indifference would need to be increased to compensate for the higher volumetric rates that result from not having a fixed charge as part of the Reform Tariff rate design.[203]

The calculation of the illustrative GBC, Table IV-27 makes apparent that the GBC is dependent on the level of retail rate in the underlying rate the Reform Tariff customer takes service on. As shown in Table IV-29, below, the retail rate for TOU-DER is approximately 6 cents-per-kWh lower than it would otherwise be without the fixed customer charge. If the starting retail rate was 6 cents-per-kWh higher than shown, the corresponding grid charge needed to ensure non-participating customer indifference would also be higher. For SDG&E, an applicable GBC for its default tiered TOU residential rate, TOU-DR1 which does not have a fixed charge, would be $18.01/kW-AC per month.

[203] The GBC will also vary based on the rate levels reflected in an applicable optional rate schedule with different pricing than the proposed cost-based default rate schedule.

Table IV-29
Illustrative Residential Grid Benefits Charge without Default Cost Based Rate

Utility	Unit	Illustrative GBC
PG&E	$/kW-AC	$18.34
SDG&E	$/kW-AC	$18.01
SCE	$/kW-AC	$17.54

5. Proposed Non-Residential Reform Tariff

Non-residential base rate structures are typically more cost-effective when considering NEM participating customer benefits and the costs of NEM benefits borne by non-participating customers. All three utilities have multi-part rate designs consisting of fixed charges, demand charges, and time variant energy charges for non-residential service. Multi-part rate design reduces the avoidance of fixed grid infrastructure and grid connection costs through NEM participation. As a result, Reform Tariff considerations for the non-residential sector primarily fall in the areas of export compensation and the application of a Grid Benefits Charge for cost recovery in those cases where existing demand charges do not sufficiently recover costs relative to the default rate in each class. We propose that non-residential customers be allowed to continue service on existing rates.

Electricity rates for the non-residential segment are more closely structured on the principle of cost causation where the various rate elements are designed based on the drivers of those costs. For example, costs driven by metering, billing, and the facilities to connect customers to the grid are typically or partially recovered through fixed dollar-per-month charges. Similarly, costs driven by the level of demand on the distribution grid are typically recovered through monthly demand charges.

The effectiveness of the multi-part rate design is also demonstrated in the results of the NEM Look Back Study Report. In various examples, Verdant makes the point that the burden of the NEM cost shift is mitigated in the non-residential class due to fixed and demand charges.[204]

The relative effectiveness of cost recovery with non-residential base rate designs leads the Joint Utilities to maintain their current non-residential base rate structures as an element of the

[204] Verdant NEM 2.0 Lookback Study, at 93.

successor tariff. The balance of our non-residential Reform Tariff proposal consists of the following elements:

1. A time-variant value-based export compensation rate;
2. A Grid Benefits Charge to supplement recovery of fixed and infrastructure costs, as well as policy/nonbypassable charge costs;
3. TOU netting and a monthly true-up period in place of the current annual true-up period; and

The non-residential export compensation rate will be based on the export weighted ACC avoided costs as described above.

A Grid Benefits Charge will also apply to non-residential rates for those rates that do not already fully recover transmission, distribution, generation capacity, NBCs, and other costs through fixed and demand charges. As most non-residential rates already recover transmission, distribution, and generation capacity costs through demand charges, the imposition of the Grid Benefits Charge may have a muted effect for most participating customers. For non-residential customers, the Grid Benefits Charge will be assessed as a dollar-per-installed kW charge, as described above. Each of the utilities offers non-residential service on a variety of rate schedules. For rate options where demand charges recover a portion of grid and generation capacity costs, additional costs may be recovered through a combination of standard demand charges (applicable to all customers on the same service) and the Grid Benefits Charge. Determination of the Grid Benefits Charge for each non-residential rate class will be performed using the same methodology described for the residential class, with the exception that the charges comprising the Grid Benefits Charge will be limited to volumetric charges thus representing only those portions of cost that are displaced by the adoption of behind the meter technologies. Adjusting the Grid Benefits Charge to accommodate and existing fixed cost recovery will avoid the recovery of the same costs through two different rate components.

We propose to adopt a monthly true-up and TOU netting periods for non-residential Reform Tariff customers, identical to the residential proposal.

Table IV-30 below displays examples of SDG&E's proposed GBCs for existing non-residential rates:

Table IV-30
SDG&E Illustrative Non-Residential Grid Benefit Charges by Rate Schedule

Tariff	Grid Benefits Charge* ($/kW-AC)
TOU-A	$21.35
TOU-A2	$15.93
TOU-A3	$21.25
TOU-M	$14.75
AL-TOU	$10.38
AL-TOU2	$9.16
DG-R	$17.36
A6-TOU	$5.01
OL-TOU	$24.69
PA-T-1	$3.55
TOU-PA	$22.91
TOU-PA2	$5.84
TOU-PA3	$13.02

* Secondary service shown.

Table IV-31
PG&E Illustrative Non-Residential Grid Benefit Charges by Rate

Tariff	Grid Benefits Charge ($/kW-AC)		
	Secondary	Primary	Transmission
B1	$20.84	N/A	N/A
B6	$19.94	N/A	N/A
B1-ST	$17.70	N/A	N/A
B10	$12.52	$11.46	$6.93
B19	$6.10	$5.17	$5.37
B19 - Opt R	$8.68	$7.55	$6.79
B19 - Opt S	$8.68	$7.55	$6.79
B20	$5.60	$5.16	$4.09
B20 - Opt R	$8.11	$7.51	$5.86
B20 - Opt S	$8.11	$7.51	$5.86
AG-A1	$17.58	N/A	N/A
AG-A2	$12.14	N/A	N/A
AG-B	$16.62	N/A	N/A
AG-C	$11.18	N/A	N/A

Table IV-32
SCE Illustrative Non-Residential Grid Benefit Charges by Rate Schedule[205]

Tariff	Grid Benefits Charge ($/kW-AC)
TOU-GS-1	$ 9.75
TOU-GS-2	$ 8.29
TOU-GS-3	$ 7.79
TOU-8-SEC	$ 7.24
TOU-8-PRI	$ 7.07
TOU-8-SUB	$ 3.50
TOU-PA-2	$ 5.31
TOU-PA-3	$ 2.72

6. <u>Update Timing</u>

To provide more certainty and enhance customer understanding, the Grid Benefits Charges for all customer classes should be updated at least once per year to adjust for currently effective rates, with each utility's respective annual consolidated filing, which typically occurs on January 1.[206] An annual update process will ensure that the charge is adjusted for any rate increases or decreases that may occur during the year and will provide the customer stability, as they will pay the same total monthly charge throughout the year. The structure and design of the charge will not be updated at the annual update. Rather, only the rate levels will be updated to reflect any pricing changes that occurred during the year through other rate changes.

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[205] GBC's shown applies to secondary service on SCE's Option-E rates for each class with the exception of the GS-1 class, where the GBC applies to Option LG. The purpose is to maintain a consistent base rate structure for each non-residential class. This also reduces the GBC for the TOU-GS-1 class for the same reason as discussed in the proposed default vs the current default rate for Residential Class section.

[206] The GBC is based on delivery and generation rate components, some of which can be updated in separate rate adjustments outside the first quarter consolidated rate change. Therefore, the GBC may be adjusted more than once per year. For example, if delivery rate components are adjusted in the January 1 consolidated rate change, and the generation components are updated in the second quarter, the GBC will experience two separate adjustments.

F. Value of Distributed Energy (VODE) Optional Tariff

1. Summary

While we believe the core tariff proposal described in this chapter meets the principles adopted in this proceeding, we also recognize that future use cases may require a dual-meter option to facilitate more advanced uses of distributed generation such as demand response or microgrid participation and some customers may prefer this approach due to its simplicity or the improved ability to monitor performance. Therefore, the utilities have also developed a "Value of Distributed Energy" (VODE) optional tariff where onsite generation would be separately metered and credited at a pre-determined rate. Participating customers would continue to be metered and billed based on their gross load like any other member of their class. The metering arrangement does allow for onsite self-supply and lends itself to future programs geared towards demand response and resiliency. This structure has been recognized as being simpler and more transparent for participating customers than other behind-the-meter generation compensation mechanisms. We do not propose that the VODE would be available for customers on the same timeline as the core tariff. Rather, this option could be developed at a later date as needed. For example, a utility could elect to offer this option to meet customer demand or to facilitate a power sharing tariff or a demand response program. The rest of this section outlines the details of this concept.

2. Applicability

Once available, this tariff would be available as an option for all residential and small commercial customers installing generation that would otherwise be eligible for the Reform Tariff and be for systems less than 1 MW in size. We propose to limit this option to customers that would most benefit from a simpler structure or who have a need to better understand and track the output of their system, but the utilities are open to stakeholder feedback regarding further eligibility.

3. Metering

Participating customers would continue to install their generators behind their primary meter, as is the case with the current NEM tariff. However, this installation would also require the installation of a separate generation output meter. This meter data would be combined with the data from their primary meter to determine the customer's gross usage and generation. This metering arrangement would allow solar-paired storage customers to use their systems for backup power while still participating in this structure. Note that this metering arrangement is distinct from traditional "Feed-in-Tariffs" where the generator is located behind an entirely separate meter from customer loads.

4. Compensation

Conceptually, the compensation from this tariff should be approximately equal to the estimated average compensation provided via the Reform Tariff to non-CARE customers. The intent is to offer similar compensation to customers as the baseline tariff but with greater certainty that they will achieve those savings. The Utilities do not propose a specific level of compensation here, but conceptually the rate would be similar to the ECR with an adder in all hours to account for any additional savings realized by avoiding retail rates.

5. Policy Adders

Since all participating customers would receive the same baseline compensation, any adders to promote adoption among certain demographics or geographies would cleanly increase the overall compensation level or achieve a specific compensation target. For example, if the baseline compensation of the tariff was $0.09/kWh, but fluctuating according to changing results from the ACC, an income-qualified adder could be provided which ensures that the resulting compensation is $0.15/kWh for a set term. This would promote easier financing and greater certainty for customer groups.

These concepts are illustrated in Table IV-33 below.

Table IV-33
Illustrative PG&E VODE Credits and Adders

Time of Export Period	Baseline VODE (ACC)	Retail Indifference Adder	Income Qualified Adder	Total
Summer:				
On-Peak	0.126	0.040	0.064	0.230
Part-Peak	0.069	0.040	0.064	0.173
Off-Peak	0.051	0.040	0.064	0.054
Winter:				
On-Peak	0.063	0.040	0.064	0.166
Part-Peak	0.043	0.040	0.064	0.147
Off-Peak	0.029	0.040	0.064	0.132
PV Profile Weighted Average Compensation	0.046	0.040	0.064	0.150

6. VODE Supports Future Use Cases

A VODE option would enable customers to better manage their gross usage and costs, and support greater consumer protection.

Under current NEM structures, customers do not have access to solar generation data through utility bills or customer education tools, because the utilities do not have access to metered solar generation data. Customers often want to see the full picture of their total usage, inclusive of what part of their onsite usage was met through solar generation.[207] Customers often also want to understand what their bill would have been without solar, which the utilities do not have information to provide.

Since this structure compensates customers outside the constraints and complexities of retail rate design, it largely solves the issues of incrementality currently faced by DERs attempting to receive additional compensation for participating in wholesale markets or providing other grid services. While markets for these services are still too nascent to propose linkages in detail here, the VODE tariff would provide a stable foundation for customer-generators that wish to provide such services.

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[207] Based on analysis of customer call transcripts and feedback from PG&E's Solar Customer Service Center Customer Service Representatives.

Greater visibility into how total usage, coupled with solar generation, impacts their overall electric costs, would enable customers to better manage costs through load management behaviors or technologies.

G. Standby Exemption for Non-NEM Solar Generators Under 1 MW Should be Eliminated

Approximately twenty years ago in D.01-07-027, the Commission extended the exemption from standby charges in the original NEM tariff to non-NEM solar customers with capacities under 1 MW. This decision is clearly anachronistic - the findings of fact include that "Small solar generating units will represent far less than one percent of California's peak demand requirements" and "Reliable solar distributed generation will produce electricity coincident with peak demand for electricity."[208] Distributed solar nameplate capacity is now well over 20% of peak demand, and the effective load carrying capacity of new solar is very low. Moreover, the statutory exemption of NEM customers from standby charges that this decision sought to mirror does not apply going forward.

While the utilities do not propose to apply standby charges to Reform Tariff customers, our GBC proposal fulfills a similar role in ensuring customer generators contribute towards the costs of the grid that they rely on. For customers that opt to not participate in the successor tariff and instead interconnect to the grid under Rule 21 non-export provisions, it makes sense to end this exemption.

Existing customers that benefit from this exemption should receive the same prevailing legacy treatment as the NEM 1 and NEM 2 tariffs, which is currently twenty years. There is no statutory requirement for any kind of legacy treatment, unlike for the NEM tariffs. However, given the small number of customers involved and that many of these customers would otherwise be eligible for a NEM tariff, we believe extending this treatment is reasonable. If the legacy treatment for NEM 1 and/or NEM 2 customers is changed in this or another proceeding, legacy non-NEM solar customer standby exemptions should change mirror those changes.

H. Virtual Net Energy Metering (VNEM) Tariffs

1. Introduction and Purpose

To improve the existing Virtual Net Energy Metering (VNEM) tariffs, we are requesting:

[208] D.01-07-027, FF 30, 31.

- Creation of two virtual net metering successor tariffs: DG-ST-VSOM for income-qualified housing, and DG-ST-V for all other customers
- Both tariffs consist of an arrangement of one or more Generating Account(s) (DG-ST-VSOM) or a single Generating Account (DG-ST-V) in combination with a unique group of Benefitting Accounts.
- All Benefitting Accounts continue to be billed on their otherwise applicable tariff (OAT).
- Exports to the grid from the Generating Account(s) are valued at the Avoided Cost – as proposed under our Reform Tariff.
- Benefitting accounts receive a dollar credit allocation based:
    - According to equal treatment rules for income-qualified housing projects (DG-ST-VSOM); or
    - According to a percentage allocation set by the owner of the Generating Account (DG-ST-V)

For the reasons discussed more fully below, we respectfully request that the Commission adopt our proposals.

2. **<u>Background</u>**

There are four virtual net energy metering (VNEM) programs in the current suite of NEM tariffs.[209] Two of these benefit income-qualified customers specifically, and two are available to all customers. Due to varying naming conventions among the three utilities, they will be referred to here as:

- Multifamily Affordable Solar Housing (**MASH**) Program: The virtual net metering program first developed to serve income-qualified customer participants, but later expanded to include participants of the New Solar Homes Partnership (NSHP)

[209] Two additional tariffs warrant mentioning – NEM Fuel Cell (NEMFC) and Generation Benefit Credit Transfer program (RESBCT). Neither of these tariffs are NEM statutes. That is true of NEMFC despite its name. The statute governing NEM is Public Utilities Code Section 2827. AB 327, codified as Section 2827.1, requires the Commission to reform certain aspects of the NEM program. By contrast, NEMFC is governed by Public Utilities Code section 2827.10 and RESBCT is governed by Public Utilities Code section 2830, neither of which are subject to the Section 2827.1 mandate. Thus, any modification to the NEMFC and RESBCT tariffs must conform to their respective governing statutes, not AB 327/Section 2827.1.

Program and customers with solar generation receiving incentives through the Income-qualified Weatherization Program (LIWP).

- Solar on Multifamily Affordable Housing (**SOMAH**): The virtual net metering program for income-qualified multi-family housing that receives an incentive through the SOMAH program.
- Virtual NEM (**NEMV**): The virtual net metering program for multi-tenant properties comprising a single project on contiguous and adjacent parcels.
- NEM Aggregation (**NEMA**): The virtual net metering program originally designed for agricultural customers but open to any customer meeting the criteria of a single owner with multiple accounts on contiguous and adjacent parcels.

Only one of these programs was established by the Legislature: NEMA was added to Public Utilities Code Section 2827 by Senate Bill (SB) 594 in 2012. The other tariffs were established by the CPUC.[210]

VNEM tariffs are fundamentally different from a standard NEM tariff in that the VNEM generation is typically located at a different location on the grid from the load it serves. For some virtual tariffs, all the generation is exported to the grid and none of the generation directly serves the load of the aggregated accounts. This differs from standard NEM, which first reduces the onsite load of the participating customer and only exports when generation exceeds load.

As a result of this difference, the generating account – when sized up to the total load on all benefitting accounts – will typically be exporting all or almost all the generation. Obviously, exporting such a large volume of energy can increase interconnection costs – partially because grid upgrades to accept the exported power are sometimes necessary. In addition, billing costs are typically higher for these complicated arrangements. Finally, unlike NEM installations at a single account, some of the assumed benefits from NEM, such as avoided distribution losses or capacity costs, may not exist for virtual arrangements. For example, if a significant portion of generation is fed back onto the primary

[210] MASH was established by the CPUC in D.08-10-036. NEMV was established by the CPUC in D.11-07-031 based on an Energy Division staff proposal to expand MASH to non-income-qualified customers.

voltage distribution system, that generation will likely go through two voltage transformations before it is delivered, incurring losses at each step.

3. Benefits of Virtual Net Metering

Virtual net metering enabled solar access for customers who could not take advantage of standard NEM. Virtual net metering was initially created to meet two specific needs: 1) the CPUC established the MASH net metering tariff to ensure bill savings for income-qualified customers in housing developments that received incentives from the California Solar Initiative (CSI) program;[211] and 2) the Legislature established the NEMA tariff initially to allow agricultural customers to meet all or part of their load at multiple dispersed meters with a single solar installation.[212] For both types of customers, the virtual tariffs enable larger, more cost effective solar installations to be built.

The CPUC expanded virtual net metering to also allow participation by other income-qualified housing developments and to enable benefits for customers in developments receiving SOMAH funding. In addition, the CPUC created a virtual net metering tariff (NEMV) for multitenant residential and nonresidential buildings. Virtual net metering tariffs have expanded access to solar for customers who would not otherwise have had that access or for whom it would have been extremely difficult to participate in net metering. The MASH and SOMAH virtual net metering tariffs have also ensured that solar bill savings reach the intended income-qualified customers.

4. Drawbacks of Virtual Net Metering Tariffs

Virtual net metering also typically creates issues for participants who are benefitting from the tariffs. For example:

- **The tariffs are extremely complicated and confusing for customers.** Customers with benefitting accounts in a virtual net metering arrangement frequently do not understand the arrangement or the billing. NEMA in particular is difficult to

[211] MASH was established by the CPUC in D.08-10-036.

[212] The Commission authorized the IOUs to implement NEM aggregation (NEMA) in Resolution E-4610.

comprehend.[213] As one indicator, PG&E's Call Center compared call times for virtual net metering calls in 2019 and 2020 and found call duration to be 16 minutes per call, significantly higher than the 10 minutes for the calls to the Solar Hot Line overall.

- **VNEM can result in consumer protection issues.** For customers in housing projects that received MASH or SOMAH funding, there are requirements (from those incentive programs) to ensure that savings reach the benefitting accounts. For NEMA customers, all accounts are required to have the same customer of record. For all other instances of virtual net metering, there may be a consumer protection issue because neither the utility nor the CPUC has any visibility into the financial arrangement between the landlord and the tenant. The CPUC has no insight into the ultimate division of the NEM bill savings between tenant, landlord, and owner of the renewable generator (whether landlord or third party).

As with standard NEM tariffs, virtual tariffs provide compensation at retail rates, which, as discussed in Chapter III, provide compensation far more than the CPUC's estimate of avoided costs. Virtual net metering tariffs result in additional costs and lower benefits than standard NEM tariffs, which are not accounted for in the standard cost-benefit analyses:

- **Virtual NEM systems do not displace onsite load, and therefore does not provide the same distribution benefits as standard NEM.** Unlike other NEM tariffs, there is no actual reduction of load at the benefitting account. The distribution, or even the transmission grid, is necessary to transport the electricity to the benefitting accounts, where it billed as if it had been generated behind the benefitting account meter at a separate – sometimes remote from the solar – location. There is no requirement that benefitting accounts be located on the same utility circuit as the generating account.

[213] To accommodate the high fluctuation in agricultural loads over the course of the year, NEMA reallocates all exports each month based on the history in the current true up period to date. This means a large winery, for example, will be allocated exports in the fall during the bottling operations that were allocated in the summer to an agricultural pump.

There is a pernicious mismatch between how virtual net metering works and the assumption in the avoided cost calculator that the generation is co-located with the load it serves.

- **Billing costs are higher for virtual net metering arrangements.** At PG&E, most NEM customers are billed in the standard Customer Care and Billing (CC&B) system whereas all customers with VNEM arrangements are billed in the Advanced Billing System (ABS). Each month, a VNEM/NEMA account costs approximately $8.40 to bill, over ten times the cost per bill of simpler NEM billing arrangements in CC&B ($0.59 per bill).

5. <u>Our Proposal for Virtual Net Energy Metering Successor Tariff</u>

Aligned with our proposal for the general market Reform Tariff proposal, the utilities propose that moving forward, virtual tariffs compensate generation at avoided cost. We propose to continue to have distinct tariffs that support income-qualified customers. As discussed for the standard NEM tariff, there are policy reasons to continue more generous virtual crediting programs for income-qualified customers on virtual net metering tariffs. These programs are also consistent with legislative direction to provide access to behind-the-meter solar to residential customers in disadvantaged communities.[214] There are several modifications to VNEM tariffs that should be implemented for all customers to align with the general Reform Tariff proposal, enhance customer understanding and reduce program costs. We propose that the VNEM tariff for new customers be modified accordingly, hereafter referred to as "Virtual Crediting Tariffs":

- All exports to the grid from the generating account will be compensated at avoided costs per the export compensation rates in the core Reform Tariff proposal.
- Revenues from exported energy will be allocated to benefitting accounts as a dollar credit.
- Unlike some current VNEM tariffs, benefitting accounts in virtual arrangements will continue to take service on any tariff for which they qualify. They will continue to be

[214] PU Code 2827.1(b)(1).

billed for actual metered usage under that tariff. Because the customer is allocated a dollar credit for exports compensated at avoided costs as described in this chapter, there is no need for a Grid Benefits Charge. Customers may continue to take service on existing tariffs for which they are eligible. There is no need for these customers to be on a particular tariff, as their compensation is fully decoupled from their retail rate.

We propose two virtual crediting tariffs:

- one for income-qualified customers (DG-ST-VSOM); and
- one for other customers that are not income-qualified (DG-ST-V).

DG-ST-V replaces both NEMV and NEMA for future installations and consists of a generating account with no load and a group of benefitting accounts located on contiguous and adjacent property. All property is under a single owner.

For both DG-ST-V and DG-ST-VSOM, the owner of the property must be the owner of the generating account. For DG-ST-V, the owner is responsible for all interconnection costs. For DG-ST-VSOM, the owner is responsible for interconnection costs if the generator exceeds one megawatt (MW). Beyond this, the other major difference between the standard virtual tariff and the low income tariff is that the low income tariff would maintain the current credit allocation rules of the SOMAH program, while the standard tariff would allow the owner to freely determine allocations.

Table IV-34
Comparison of DG-ST-V and DG-ST-VSOM

Tariff	Credit for Exports	Interconnection Costs	Credit Allocation	Generating Account	Benefitting Accounts	Geography
DG-ST-V	Avoided Cost	Paid by applicant	Owner Determined	Single generating meter; no load permitted other than that required by the generator	Owner or Tenant	Continuous/ Adjacent Parcels with same Owner as generating account
DG-ST-VSOM	Avoided Cost	Paid by applicant when system is >1 MW	Qualifying Housing Rules	Multiple generator meters allowed; no load permitted other than that required by the generator	Owner or Tenant	Single project on Continuous/ Adjacent Parcels with same Owner as generating account

a) <u>The Joint Utility Proposal Brings Equity, Clarity, and Transparency to Virtual Crediting</u>

First, by compensating eligible generators at avoided cost, our proposal ensures that beneficiaries of theses tariffs are not unduly subsidized by other customers. As demonstrated above, even applying the same export compensation rates to virtual crediting tariffs as the baseline tariff may overcompensate these customers. However, for the sake of simplicity we propose to use the same methodology as under the baseline tariff.

Our virtual credit proposal also advances consumer protection. The simplicity and clarity of the tariff provides customers/tenants on benefitting accounts with a clear value for their allocation from the renewable generator. This allows the customer/tenant to easily compare the value they receive from the allocation to the price they pay to the landlord for that allocation, whether increased rent or monthly payment. Without the ability to provide CPUC oversight of the customer experience, our tariff gives the customer the tools to better understand their value proposition and make a more informed decision about participation. For virtual arrangement replacing NEMA, the clarity of the credits is a significant improvement over the confusion NEMA customers experience today.

b) <u>Our Proposal provides a solution for all customers</u>

Our proposal would establish a balance that will ensure continued access for customers who cannot have dedicated, behind the meter solar systems for financial or physical reasons while simultaneously minimizing the impact on customers who do not today have access to NEM and likely never will.

I. <u>Enabling Dynamic Load Management Capabilities</u>

We propose that customers interconnecting under the proposed default tariff would require certain communications and cyber security capabilities, for both PV solar and energy storage systems. The universal interconnection configuration requirements as described below would ensure any third party *could* control the device if the customer chose. Active cyber security, communications capabilities and information sharing are necessary components to ensure that DERs have the capabilities needed for California to realize its vision around these technologies, and that they are dispatchable in times of high grid stress. Standardizing these proposed requirements will improve simplicity, understandability, consistency between utilities, and equity among customers.[215] The Commission should adopt the following guidelines to ensure the safety of the grid and enable the state's vision of DERs.

1. <u>All DER owners shall be required to maintain active cyber security monitoring of their systems as a condition of operation</u>

First, we propose that all DERs interconnecting under this tariff should be required to maintain active cyber security monitoring. Unmanaged and unsecure DER connected to the grid represents the largest threat to the future grid. Attacks on key inverters could result in the grid shutting down. For example, SDG&E will soon have over 1.5 GW of distributed nameplate capacity within its service territory. An attack that trips these systems offline in a coordinated fashion would most likely crash the grid and lead to widespread outages. Worse, injecting destructive commands into these

[215] Guiding Principles B, F, G.

devices could cause persistent energy shortfalls for months or years, as increasing dependence is placed on these resources. The utility should not be held accountable for a customer's device failing to operate due to equipment failure or cybersecurity breach. Consistent with supply-side resources, distributed generation facilities should be responsible for maintaining their own systems and ensuring that they function properly. Ratepayers should not pay for device operational deficiencies of other customers.

To ensure DERs have the potential to provide grid support and be able to respond to grid needs nimbly and effectively, all DERs must have certain communications capabilities. Plug-and-play, interoperable communications are needed to ensure that DERs can be managed at scale across multiple vendors. Requiring the same communications capabilities for all devices increases the likelihood that these devices can be effectively coordinated and controlled, increasing the likelihood their capabilities and value can be realized.

We propose that all DERs taking service on the Reform Tarif must be compliant with the IEEE 2030.5 networking standard in the manner described in the Common Smart Inverter Profile ("CSIP"), in accordance with Rule 21. Adopting these requirements would build on an existing established method for all three utilities and would minimize any inconsistencies in requirements statewide. This standard enables utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, electric vehicles, and other functions.[216]

Any inverters that are replaced, regardless of when original interconnection occurred, should be required to provide communications and all current operating requirements and obligations.

All inverters, including those for energy storage, must support the management and dispatch of the unit in accordance with a schedule.

2. <u>Information sharing between utility and device should come at no additional cost</u>

The default IEEE 2030.5/CSIP requires information sharing at no additional cost, giving access to real- and near-time data necessary for utility planning in the provision of operational flexibility and DER enablement. This feature supports both operational and long-term system planning and

[216] https://standards.ieee.org/standard/2030_5-2018.html.

ensures the utilities and ratepayers do not have to pay vendors for device information. Additionally, customers who choose to invest in these technologies should not be penalized if they change aggregators. Additional requirements for non-proprietary communications infrastructure for inverters and local gateways will protect customers and minimize their costs if they do choose to change aggregators.

3. **Communications capabilities should be tested prior to energization.**

To ensure the value of these systems to both the customer and the grid can be realized, DERs should be required to provide proof of compliant, certified communication equipment or systems as a condition of energization under Rule 21 interconnection requirements. Requiring a commissioning test to validate communications will prove that the system can be operated and that in the future, if the utility were to call on the device to respond to grid conditions, that capability would already exist. This is a critical piece of being able to effectively execute Distributed Energy Resources Management Systems (DERMS) and realize the maximum value of DERs when moving toward California's GHG reduction and climate goals.

V.

INCOME-QUALIFIED PROPOSALS

A. Introduction

The Joint Utilities are committed to making progress supporting the goals of the CPUC's Environmental and Social Justice (ESJ) Action Plan ("ESJ Action Plan").[217] The ESJ Action Plan goals include specific considerations for equity and equal access throughout CPUC proceedings and are guiding principles in this portion of our proposal. In this chapter we first provide an assessment of the existing programs that provide access to distributed renewable generation, and then present our proposals to complement those existing programs. This testimony is organized as follows:

- Section B: Solar Incentive Programs – provides an overview of existing solar programs including funding and expected benefitting-customers;
- Section C: Proposed Transitional Discount for Income-Qualified Customers – provides an overview of our Income Qualified Discount (IQD) proposal to encourage adoption of behind-the-meter solar for low-income customers and disadvantaged communities through a discount on the fixed charge component of our Reform Tariff; and
- Section D: STORE Proposal – present out Savings Through Ongoing Renewable Energy (STORE) pilot program that provides subsidies for storage to income-qualified customers. This program is intended to mitigate the adoption gap that we observed with rooftop solar as behind-the-meter storage adoption grows. The total funding for this program would be $330 million dollars over three years, and we estimate that the program would benefit approximately 25,000 low-income customers.

B. Income-Qualified Proposal Considerations and Objectives

Our Reform Tariff proposal will benefit all non-participating customers—including income-qualified customers and disadvantaged communities—by eliminating the cost shift for new distributed generation installations, as discussed in Chapter 4. While we believe that eliminating the cost shift is the

[217] CPUC. 2019. "Environmental and Social Justice Action Plan." Available: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/Infrastructure/DC/Env%20and%20Social%20Justice%20ActionPlan_%202019-02-21.docx.pdf.

best way to benefit the most customers, we also have concerns about the existing adoption gap between non-low, higher-income customers and lower-income customers.

We currently provide income-qualified customers increased access to distributed generation through several existing programs, some of which are fully funded through 2030. These programs are designed to pay for the majority or all the capital expenditures for customers to install a solar PV system. Additionally, income-qualified tariffs aim to support customers who live in multi-family housing and who cannot install solar directly on their rooftop. However, these programs do not fully address the inequities of the existing NEM program. We aim to address these inequities in three ways described in this section.

First, to complement the existing suite of low-income solar access programs, we propose to remedy the existing NEM tariff's disincentive for California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers to invest in distributed generation. This disincentive occurs because NEM compensation is based on retail rates, which are lower for CARE and FERA customers. This is illogical because generation provided by non-CARE customers is no more valuable than generation provided by CARE customers. It also does not make sense from a policy standpoint to provide a regressive subsidy that structurally benefits wealthier customers at the expense of lower-income customers. The Reform Tariff is described in detail in Chapter IV.

Second, we propose a transitional Income Qualified Discount (IQD) to help ensure continued access to rooftop solar for lower-income customers. This tariff proposal provides a discount on the Grid Benefits Charge to provide income-qualified customers a better value proposition than higher-income customers. Table V-35 shows the payback period for income-qualified customers using existing programs and those on our proposed IQD compared to higher-income customers on the Reform Tariff. This proposal is designed to encourage continued adoption of rooftop solar by income-qualified customers and redress the inequity of the existing NEM program design that disadvantages CARE customers.

Table V-35
Illustrative Estimated Payback[218] Periods of Income-Qualified Customers with Existing Programs, the Proposed Income-Qualified Discount, and the Joint Utility Core Tariff Proposal (years)[219]

Utility	Payback for Customers Benefitting from Existing Income-Qualified Programs	Proposed Income Qualified Payback (Standalone Solar)	Proposed Non-Income Qualified Payback (Standalone Solar)
PG&E	0	10	19
SDG&E	0	10	15
SCE	0	13	18

Finally, we propose the STORE pilot to provide storage to about 25,000 income-qualified customers with a prioritization for customers experiencing outages due to wildfire threats and customers with medical needs. To maximize the benefit of these resources to all customers, we propose that the utility retain dispatch rights and customers participate in a to-be-developed dispatch program. We propose developing details of the STORE pilot, including participation in a dispatch program, be developed through a stakeholder process. This proposal is intended to mitigate a storage adoption gap like the observed under-representation of lower income households among solar adopters. To mitigate the bill impact of this program, including the impact on low-income households, we propose funding levels tied to the reduction in cost shift of the adopted NEM successor tariff. Table V-36 provides an overview of the new discounts and programs proposed in this Chapter.

[218] Payback calculations are discussed in Chapter IV.

[219] The payback period estimate for benefitting customers includes income-qualified customers and disadvantaged communities under the DAC-SASH program as well as tenants in a building with solar installed under the SOMAH program. It is possible under the SOMAH program that the building owner may face a non-zero payback time for the portion of the system dedicated to common area load. DAC-GT or the Community Solar Green Tariff (CSGT) provide immediate, guaranteed savings and do not require the installation of any new generating equipment on site. We recognize that in the case of DAC-SASH projects, capital costs can emerge that are not covered by incentives from the program (and often covered by the program administrator through other means such as financing. This analysis does not include MASH or SASH, since incentives for those programs are no longer available or scheduled to be fully reserved by the end of 2021.

Table V-36
Joint Utilities' Proposed New Income-Qualified Discounts and Programs

	Income-Qualified Discount (IQD)	Savings Through Ongoing Renewable Energy (STORE) Pilot
Eligibility	CARE/FERA Enrolled	CARE/FERA Enrolled
Enrollment Period	3 years after implementation of Reform Tariff (e.g. 2023-2026)	2023-2026
Term	Equal to the forecasted simple payback (e.g. 12 years for PG&E)	One-time free installation and potential dispatch benefits over life of system
Estimated Benefiting Customers [1]	166,577	25,357
Estimated Program Cost	$376 Million	$330 Million

[1] The estimate of benefitting customers for the IQD assumes annual uptake equal to the average CARE NEM customer enrollment over the past 3 years. The estimate of benefitting customers for the STORE pilot assumes a cost of $13,000 per customer including cost of the battery and any necessary upgrades. The estimate does not reflect any administrative costs.

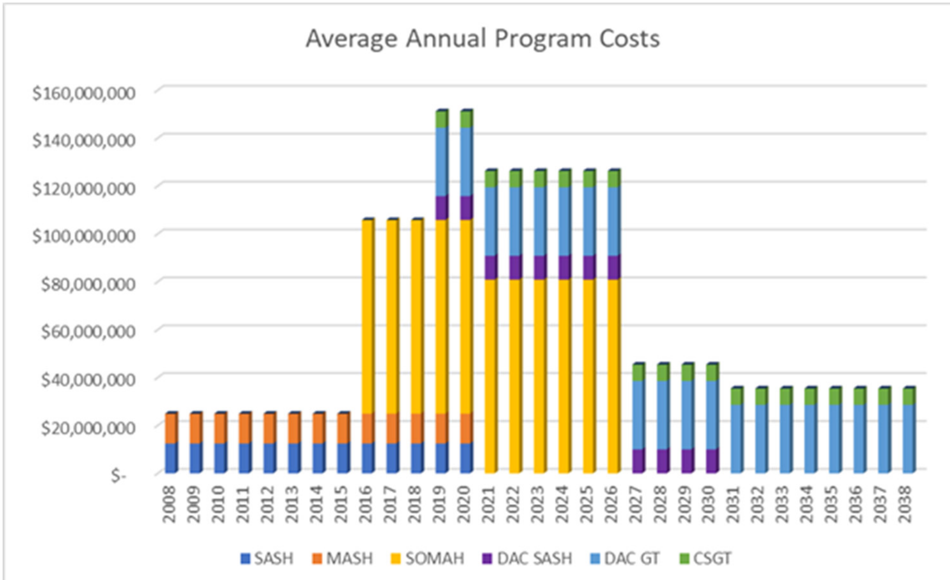
These programs and rate elements are meant to work together to increase investment in clean energy resources to benefit ESJ communities (ESJ Action Plan Goal 2) and increase climate resiliency in ESJ communities (ESJ Action Plan Goal 4). We have also added opportunities for outreach and public participation for ESJ communities (ESJ Action Plan Goal 5) in designing the STORE proposal, as described in Section D.

C. Solar Incentive Programs

Funding for existing income-qualified solar access programs is both robust and in transition. We commend the Commission for its attention to this issue and in developing a comprehensive suite of programs designed to reach many income-qualified customers. As presented below in Figure V-33, since 2008, the CPUC has adopted $2 billion in funding for programs with approximately $1.3 billion remaining to be spent through 2038. Currently, the Single-Family Affordable Solar Homes (SASH) and Multi-Family Affordable Solar Homes (MASH) programs are in the process of program completion while the Disadvantaged Communities Single-Family Solar Homes (DAC-SASH) and Solar on Multifamily Affordable Housing (SOMAH) programs, along with Disadvantaged Community Green

Tariff (DAC-GT) and Community Solar Green Tariff (CSGT), are in the early stages of enrollment or installation.

Figure V-33
CPUC-Approved Funding of Existing Low-Income Income-Qualified Solar Programs (2008-2038)



Of the $2 billion in program funding illustrated in Table V-37, approximately $25 million is funded annually through ratepayer collection and approximately $125 million is funded annually through cap-and-trade funds. Forty-nine percent of program budget earmarked for cap-and-trade funding is required to be funded via ratepayer collection if sufficient cap-and-trade funding is not available in the future.[48] Program funding is not included in our cost shift estimate for the NEM program, although it similarly impacts non-participants, including non-participating lower-income customers.

The current adopted funding for these incentive programs is robust, and the programs are likely to help address barriers to adoption among underserved populations. As displayed in Table V-37 below, if the various incentive programs focused on offering solar access to underserved populations succeed in meeting targets, then upwards of 227,000 such households will gain access to solar.

Table V-37
Target-Based Solar Programs Forecast / Current Program Inventory

All IOUs	Funding Period	Total Participants Expected	Rate Type	Program Cost
SASH	2008-2020	9,627	NEM	$162,000,000
MASH	2008-2020	20,679	VNEM	$162,000,000
SOMAH	2016-2026	106,645	VNEM	$875,364,348
DAC SASH	2019-2030	8,543	NEM	$120,000,000
DAC Green Tariff	2019-TBD	67,785	Discount	$572,028,813
CSGT	2019-TBD	13,766	Discount	$136,421,845
Total	-	227,045	--	$2,007,815,005

We recommend against enhancing the adopted funding of the existing roster of allowable incentive program activity until after the next program review cycle in 2024. The program activities that we considered in arriving at this recommendation included those of SASH, DAC-SASH, MASH, SOMAH, DAC-GT, and CSGT. Gauging these programs' progress against targets will provide a critical input for supporting and understanding adoption within underserved communities. We do not recommend expanding funding of these programs until after the 2024 evaluation period of DAC-SASH and SOMAH because at that time we will be better able to determine if changes to the programs or additional funding are needed to ensure solar adoption continues in underserved communities.
The effort could be coordinated with the workshop (described below) to assess the effectiveness of the IQD.

D. <u>Proposed Transitional Discount for Income-Qualified Customers</u>

We propose a transitional tariff discount for CARE/FERA-enrolled customers, called the IQD. The IQD provides a discount on the Grid Benefits Charge (GBC) and guarantees that income qualified customers will pay only a nominal amount toward the costs underlying the GBC. The IQD would be applied in conjunction with programs for which a customer might qualify, including the California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA) and Medical Baseline programs, and would operate alongside any existing applicable solar incentive programs such as DAC-SASH. The IQD would be applied in conjunction with programs for which a customer might qualify, including the CARE, FERA and Medical Baseline programs, and would operate alongside any existing applicable solar incentive programs such as DAC-SASH.[47] We propose the IQD GBC for customers receiving the IQD be reduced to $1.50 per kW-AC for qualifying customers, which is a nearly 90% discount to the proposed illustrative SDG&E GBC provided in Chapter IV.

1. Transition Period and Eligibility

The IQD would be available to CARE and FERA-enrolled customers who receive permission to operate (PTO) within the first three years from the date of implementation of the successor tariff. One year prior to the expiration of the IQD, we propose that the Commission hold a workshop to examine the success of the Reform Tariff and DG-ST programs in providing access to solar for income-qualified customers. The workshop should assess the following:

- Adoption among qualifying customers before and after tariff reform;
- Assessment of prices of solar to determine whether continuing the subsidy is necessary; and
- Estimation of cost shift of the program.

Based on this information, the Commission could determine whether to extend the IQD or propose adjustments. If no action is taken by the Commission three years after the successor tariff is implemented, we propose the IQD would expire for all new successor tariff income-qualifying customers. Income-qualified customers who took service on the successor tariff with the IQD and remain eligible for the discount would continue to receive the discounted GBC rate for a period equal to their forecasted simple payback period for each utility. For example, if PG&E customers have a forecasted payback period of 10 years, then customers would be entitled to the IQD for 10 years from their PTO date.[220]

2. Anticipated Cost and Cost Recovery of Income-Qualified Discount

Using the total eligible population for the IQD, the Joint Utilities estimate a total subsidy of $376 million for all three utilities over the discount period. We propose that these costs be recovered

[220] We propose to calculate the IQD payback period once for each utility using the same methodology used to calculate simple payback periods in this testimony to be determined upon rates in effect at or near the time of implementation.

from all customers. The determination of cost allocation and recovery will be determined in each utility's General Rate Case (GRC) Phase 2 proceeding to evaluate the unique rate design priorities and rate level pressures faced by each utility.[221]

E. S.T.O.R.E. Pilot: Savings Through Ongoing Renewable Energy

1. Introduction and Overview

This section of testimony describes the purpose, design, scope, community engagement, and costs for our STORE program. The STORE pilot is a behind-the-meter storage incentive for income-qualified customers.[222] Designed to cover the cost of customer-sited battery energy storage systems, the program provides an opportunity for technology adoption to this subset of customers whose adoption of new clean energy technologies has typically lagged. We propose to file an Advice Letter containing details of the pilot, including its evaluation and measurement plan, after a robust stakeholder process.

Market-based incentives like this one have received broad support in California and have helped to promote new and clean renewable energy technologies and efficiency upgrades. These incentives are designed to lower barriers to entry and provide access for new technologies to consumers who may not otherwise adopt them. As described in Chapter 1 of this testimony, NEM has successfully promoted behind-the-meter solar in this way. Historically, these programs have tended to support higher-income customers.[223] In contrast, STORE focuses on incenting income-qualified customers, helping bring them to the front of the adoption curve in order to meet California's energy and environmental goals. Currently for PG&E, with only 4.5% of storage adoption coming from CARE customers, there is a significant gap to bridge to reach the levels achieved in standalone PV, where 14% of adopters are CARE customers.

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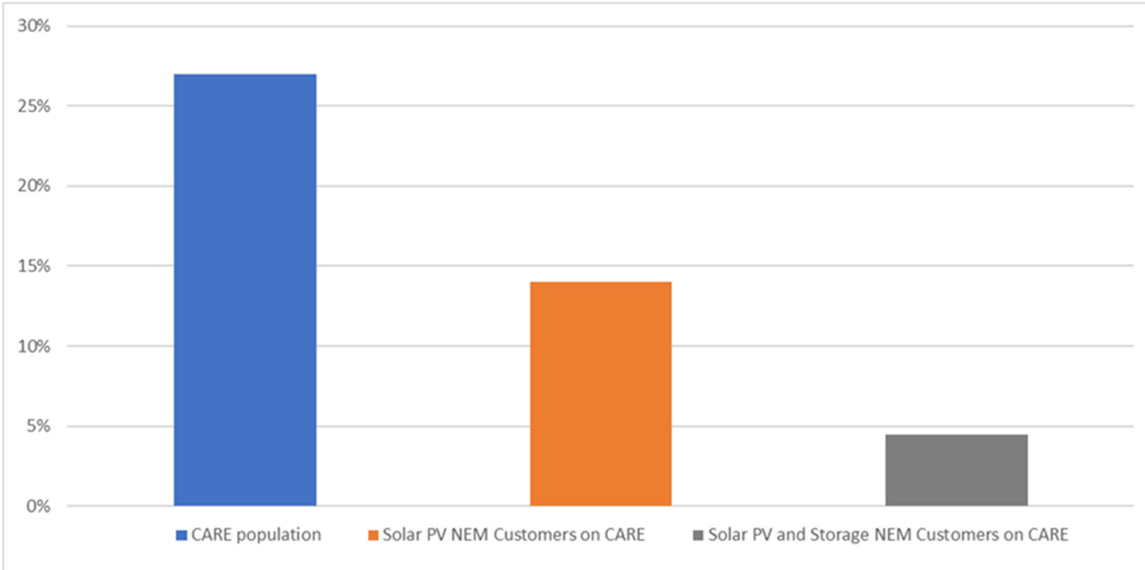
[221] The Joint utilities propose to initially recover these costs through the Public Purpose Programs charge, but each utility may propose a different recovery mechanism for these charges in the future. SCE has a pending proposal for an allocation protocol for transportation electrification and wildfire related costs, a similar approach will be applied to income-qualified program costs.

[222] Income-qualified customers means customers enrolled in CARE/FERA.

[223] Bird and Hernandez, 2012; Scavo *et al*., 2016; Parsons *et al*., 2018.

Figure V-34
Adoption Levels for CARE Customers of Standalone PV vs. Storage (PG&E)



The STORE pilot would purchase batteries for income-qualified customers, resulting in a significant reduction in payback for their system versus payback for CARE solar-paired storage systems that do not receive a battery through the STORE program. The table below shows these values for the three utilities, assuming no participation in the existing solar access programs described earlier in this chapter.

Table V-38
Payback STORE vs. NON-STORE under CARE Reform Tariff (2021 ACC)

Utility	Estimated Payback (CARE Solar + Storage)	Estimated Payback (CARE Solar + STORE Program)
PG&E	12	8
SDG&E	11	7
SCE	13	7

2. Technology – Behind the Meter Batteries with Utility Dispatch

California is not new to providing incentives for behind-the-meter storage. The Self-Generation Incentive Program (SGIP), which now focuses on behind-the-meter storage, has existed in some form or another since the mid-2000s.[224] Although residential storage incentives categories are already fully subscribed in some jurisdictions,[225] SGIP continues to provide incentives for customers to install behind the meter storage. STORE leverages technological and programmatic best practices from SGIP but contains key elements, to be detailed herein, that separate it as a standalone pilot. Customers who receive SGIP are not eligible for STORE. While SGIP has certain budgets targeted toward lower-income customers, STORE is a program designed specifically for lower-income customers. Additionally, STORE features utility dispatch of the storage device, which is intended to promote the transition to a cleaner grid while creating a net benefit for all ratepayers and participants.

Behind-the-meter battery technology, like solar technology ten years ago, has undergone dramatic improvement in functionality and equally dramatic downward movement in cost. Software improvements have allowed for customers to install systems and to leave them to manage themselves ("set it and forget it"). Like PV, these batteries can provide their service without requiring engagement from the customer. Paired systems in particular "represent a unique and disruptive power sector technology capable of providing a range of important services to customers, utilities, and the broader power system."[226]

Behind-the-meter storage has moved into a phase of large-scale commercialization in the U.S.[227] However, it remains a technology unrecognizable by many, its uses and benefits not yet well understood by the population at large. California has been and continues to be a world leader in promoting technology and supporting new markets that help it to meet its highest goals for GHG reduction. In this

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[224] The CPUC established the SGIP program in 2001 in D.01-03-073.

[225] https://www.selfgenca.com/home/program_metrics/.

[226] Zinaman, Bowen, Aznar. "An Overview of Behind-the-Meter Solar-Plus-Storage Program Design." National Renewable Energy Laboratories, 2020.

[227] Spector, Julian. "As Residential Solar Deployments Fell, the US Home Battery Market Powered On." GTM, 2020.

context, behind-the-meter storage will not be any different, except perhaps in one way: by engaging income-qualified customers early in the development of the technology and by delivering the subsidy directly to those who need it most.

3. STORE: Equity through Energy Affordability and Ownership

In addition to creating access to advanced DER technology for income-qualified customers, STORE aims to provide subsidies to targeted populations most at risk of falling into energy poverty. For example, income-qualified rural customers who face regular public safety power shut off (PSPS) events and who have little energy resiliency will be prioritized for the STORE incentive. This and other categories of customers will be further defined in the eligibility portion of this proposal.

STORE aims to support California's effort to provide equitable access to technology as it moves towards decarbonization. The program leverages learning and networks from current income-qualified programs to further technology adoption of behind-the-meter storage for income-qualified customers. This incentive program aims to achieve three key goals: 1) offer income-qualified customers the opportunity for long-term energy bill savings; 2) engage income-qualified communities early in the adoption curve of behind-the-meter storage technologies; and 3) create grid benefits for all customers through utility dispatch during crucial times.

4. Pilot Program Design

The STORE pilot program would provide a battery for eligible customers through either:

1. Contracting with an installer/manufacturer to purchase a large quantity of batteries at a discount potentially through a competitive process; or
2. Providing a direct subsidy to customers or the installers working with those customers similar to the existing Self-Generation Incentive Program (SGIP).

The route for deployment would be selected by each utility. After purchase, the customer would assume responsibility for maintenance and eventual disposal of the storage system, unless that service is offered under a contract with an installer/manufacturer under Option 1 above.

We will work with providers to establish standards regarding closed standards for batteries provided by vendors, capabilities for providing interval meter data, and dispatch protocol.

Where needed, customers would be eligible for additional funds for electrical upgrades in their home necessary to install the storage system. The utilities will work with stakeholder to establish a cap for upgrades.

The implementation of this program will adhere to the guidelines developed by CPUC decisions such as 18-06-027, which describe the responsibilities of the program administrator.

5. Utility Dispatch of Batteries

As part of the program, participating customers will allow utility dispatch rights over the storage resource – either directly or via an aggregator contracted by the utility. Utility dispatch rights will allow the utilities to optimize the value that the battery creates for all customers through participation in market participating or demand response programs. There are various potential programs in existence and other programs in development that the utilities can elect for these batteries to participate in, but we decline to propose a single program in this testimony. Instead, we propose to work with stakeholders through CPUC workshop processes to design a utility-dispatch program where customers who received a storage system through the STORE pilot continue to realize bill savings from the storage system.

Examples of how other utilities have developed programs that allow for battery dispatchability, ranging from peak shaving to resiliency, are outlined in Table V-39.

Table V-39
Examples of Utility Storage Dispatch Programs

Program/Pilot Name	Description	State	Funding Source	Who Owns?
Connected Solutions	Peak reduction program. Utility pays customer-sited battery owners incentive of either $225/kW or $50/kW for use of stored energy during peak events	MA, RI, CT *(National Grid or Eversrouce)*	Ratepayers	Customer
Solar Choice + smart thermostat	Smart thermostat demand response program	SC, NC *(Duke Energy)*	Ratepayers	Customer
Soleil Lofts Building VPP	Storage (and solar) included in each of 600 units built in this purpose-built complex. Utility to control batteries to reduce peak demand.	UT *(Rocky Mountain Power in part only)*	Ratepayers (funding DR aspect only; developer owns batteries)	Developer
Resilient Home Program	Customers pay an $30/month for 10 years (or $3000 up front) for a PowerWall to use for resilience. Customers may also BYOD	VT *(Green Mountain Power)*	Ratepayers + customer (can be customer for equip. if BYOD)	Utility (Customer if BYOD)
Battery Storage Pilot Program	Customers pay $50/month (or $4866 up front) for two batteries installed, used, and maintained for 10 years. BYOD expected in future. Requires TOU rate use.	NH *(Liberty Utilities)*	Ratepayers + customer	Utility (Customer if BYOD)
Smart Energy Optimizer Pilot	Utility subsidize storage equipment for customer resilience/outage use if SMUD can use at least 51% of energy stored in device for dispatch use up to 120 days/year.	CA *(SMUD)*	Ratepayers	Customer
VPP Pilot	Customers receive $250 to enroll and allow aggregator to test dispatch scenarios	CA *(SCE)*	Ratepayers	Customer

6. Comparison to SGIP

While SGIP shares environmental, customer resiliency, and market transformation objectives with the STORE program, STORE modernizes the SGIP program by including utility dispatch control which improves upon the SGIP program by ensuring more benefits to non-participants. When the battery is 100% customer operated as is the case with SGIP, it may not be optimized to time-of-use rates[228] let alone real-time grid conditions and, while the storage system may provide resiliency for the customer, it does not support grid support or resiliency in the way that dispatchable generation does. By requiring dispatch of the resources at times that are most valuable to the grid, the STORE pilot provides additional value to non-participating customers.

Another central difference between the two programs is participant eligibility requirements and prioritization, as described in detail in the next section. The STORE eligibility criteria are focused solely on income-qualified customers and allow for prioritization of higher needs customers within that group. This allows us to target those customers who could benefit the most from the storage systems based on the customer's financial situation, likelihood of wildfire related power shutoff, and medical needs.

Finally, the STORE pilot allows for some flexibility in how storage resources are procured. In SGIP, customers are eligible for funds up to a cap which provides no incentive for manufacturers and installers to price storage systems below the cap. For the STORE proposal, we would like to explore bulk procurement of storage resources by the utility through either bilateral negotiations or a competitive process with the idea of reducing the per unit cost of the batteries and providing benefit to more income-qualified customers.

7. Eligibility

General customer eligibility criteria for the STORE Pilot Program is as follows:

- CARE/FERA enrolled customers in single family homes with standalone, individually dedicated solar (*i.e.*, CARE/FERA NEM 1.0 and NEM 2.0 customers); or
- New solar CARE/FERA enrolled customers installing solar at their residence.

For existing NEM 1.0 and 2.0 CARE/FERA customers to participate in the STORE Pilot, they will be required to transition to the NEM successor tariff.

[228] As of April 2020, residential customers enrolled in SGIP are required to be on specific time-of-use rates.

Prioritization of customers will be developed through a comprehensive stakeholder process led by utilities and supported by customer advocacy groups, subject matter experts, community organizations, vendors and aggregators. For example, the collaborative stakeholder process might identify a priority and eligibility qualification for Medical Baseline and Life Support Customers in High Fire Threat Districts and High Fire Risk Areas (HFTD/HFRA). Another example of prioritization may be for tribal communities in high fire threat areas, also an area of alignment with the CPUC's ESJ goals.

For example, if a utility intends to begin the program in 2023, they may start outreach and allow sign-up for Medical Baseline customers in high fire-threat zones in Q3 of 2022, followed by the same opportunities for CARE/FERA-enrolled customers in Q4 of 2022, followed by opening the program to all CARE/FERA-enrolled customers in 2023.

Once priority groups have been identified, the utilities may partner with lower income clean energy advocacy groups to facilitate customer adoption. Input in the stakeholder process will include invitations to private companies, non-profits and state-run agencies with special focus on equity and environmental justice. The CPUC has already developed a network of advisory boards and programs to assist and promote state and federal low-income programs. This network includes the Low-Income Oversight Board, the CPUC and CEC Disadvantaged Communities Advisory Group, and the State Workforce Development Board. We intend to leverage existing networks where possible to achieve efficiencies and lower administrative costs of outreach to potential participants.

In addition to the stakeholder processes for identification of priority customers and implementation, STORE could also add to jobs. Using existing income-qualified programs' workforce development resources will bring co-benefits for communities and will capitalize on efficiency and investment from these programs. We would like to use the stakeholder process to explore potential opportunities for creating jobs in ESJ communities.

8. <u>Program Funding, Duration, and Size</u>

The STORE program will be funded with cost shift savings realized by the reform of the NEM program as we have proposed. For the first three years after the Reform Tariff is in place, ten percent of the cost shift savings that exist because of transitioning new customers to the successor tariff will be allocated to a fund earmarked for STORE. With this funding approach, the following estimated number of storage devices would be available:

Table V-40
STORE Program: Estimated Cost and Benefitting Customers

	Cost Shift Reduction, DGST (millions)			Benefitting Customers			Total Benefitting Customers	Annual STORE Budget (millions)
Year	PG&E	SDG&E	SCE	PG&E	SDG&E	SCE	IOU	IOU
2023	$ 230	$ 67	$ 168	1,770	516	1,296	3,582	$ 47
2024	$ 545	$ 144	$ 410	4,190	1,110	3,151	8,452	$ 110
2025	$ 869	$ 215	$ 648	6,687	1,651	4,985	13,323	$ 173
Total	$ 1,644	$ 426	$ 1,226	12,648	3,277	9,432	25,357	$ 330

Table V-41
Authorized SGIP Ratepayer Collections, 2020-2024 and Expected STORE Collections 2023-2026

	Authorized SGIP Ratepayer Collections, 2020-2024	**Expected STORE Collections 2023-2026**
Utility	Total Collection (millions)	Total Collection (millions)
PG&E	$ 360	$ 164
SCE	$ 280	$ 123
SDG&E	$ 110	$ 43
Total	$ 750	$ 330

We propose that, following a final decision in the NEM successor tariff proceeding, the utilities jointly would provide a forecast of savings from the adopted successor tariff compared to a status quo of NEM 2.0 for future adopters of solar. This forecast would estimate the cost shift consistent with the methodology we used in this testimony and described in Chapter 3 to set the budget for the three years of this program. This budget would not be updated over the course of the program based on actuals to provide program funding certainty.

While program funds would be collected over a period of three years, funds collected but not spent in those first years could be spent up to six years after the implementation of the successor tariff. We propose that the CPUC review program spending a year before the end of the program to consider changes to the program if funding is underspent (e.g., higher portion of funding for electrical upgrades, targeting new construction, reallocation to low-income electrification efforts).

VI.

IMPLEMENTATION, ME&O AND CONSUMER PROTECTION ISSUES

A. Introduction and Purpose

We are committed to implementing a reformed distributed generation successor tariff (Reform Tariff) proposal – or an alternative NEM Successor Tariff established through this proceeding – as soon as is practicable, while supporting customers and industry stakeholders with marketing education and outreach (ME&O) to help them navigate the transition. In this Chapter, we outline a proposed implementation process and ME&O approach for transitioning to the Reform Tariff. Additionally, this chapter describes how the proposed Reform Tariff would support customer understanding and consumer protection per the principles articulated in D.21-02-007 issued February 17, 2021 that a successor tariff should "enhance consumer protection measures" and "be transparent and understandable to all customers". This testimony is organized as follows:

- Sections VI.B. Implementation of the Reform Tariff – Outlines implementation timing and requirements for the tariff, including new tariff schedules, interconnection activities and billing
- Sections VI.C Marketing, Education, and Outreach – Describes ME&O activities to support customer understanding of the Reform Tariff
- Section VI.D. Consumer protection considerations – Discusses how the Reform Tariff will support and inform Net Energy Metering consumer protection measures
- Section VI.E. Revenue Allocation and Cost Recovery

B. Implementation of the Reform Tariff

To bill customers on the Reform Tariff or any new NEM tariff, changes to utility billing systems will be required. The requirements to accommodate a Reform Tariff will vary by utility, given that each utility's billing system requirements are different. However, all three utilities will require changes across multiple processes and platforms related to interconnection, meter data management, bill calculation, and bill presentment to accommodate a new successor tariff. For our proposed Reform Tariff, key changes include:

- The addition of a Grid Benefits Charge
- New rate structures (for PG&E and SDG&E)
- Treatment of export compensation credits
- Modifications to netting logic based on TOU periods
- A monthly, rather than annual, true-up process
- Bill presentment of new line items; and
- Updating of existing bill management tools (e.g. rate analysis tools)

1. Billing Implementation Timing

Substantial changes will need to be made to each utility's billing systems and supporting platforms to bill customers on our proposed Reform Tariff, or on any other NEM proposal of similar complexity. We estimate that the implementation of a new Reform Tariff would occur 12-24 months following the issuance of a final decision adopting a new tariff structure. This initial estimate of time assumes the prompt completion of:

- Advice letter preparation and submittals to implement new tariffs and forms;
- Advice letter approval process, including responding to inquiries from Energy Division staff;
- Identification of technical billing requirements associated with the approved successor tariff across multiple rates and NEM sub-schedules; and
- Code and test changes across billing and supporting platforms.

Also, timelines to implement a successor tariff may vary by each utility due to different billing system capabilities, and other competing regulatory directives that require billing system changes. PG&E is pursuing updates to our billing systems in the next few years which will need to be coordinated with the successor tariff implementation and could potentially result in implementation delays.

2. Establishing a Cutoff for NEM 2.0 Eligibility and Enacting the New Tariff

NEM 2.0 eligibility for new distributed generation customers should end as soon as possible due to the significant cost shift that is "locked in" for each additional month that customers remain able to take service on the current NEM 2.0 Tariff. This is particularly true if new NEM 2.0 customers are allowed the 20-year "Legacy Treatment" (eligibility period for taking service on the tariff) that is allowed for existing NEM 2.0 customers. Each month of additional customer interconnections permitted under the current NEM 2.0 tariff in 2022 adds approximately $935 million over a 20-year period to the total NEM cost shift from participant to non-participant customers.[229] We ask that the Commission set a clear deadline after which no new DG customers will be able to take service under NEM 2.0, and that this deadline occur as soon as possible after a final decision that clarifies the NEM successor tariff. An expedient transition to the successor tariff is needed not only to eliminate further cost shift from NEM 2.0, but also to manage the "gold rush" of new customer interconnections that we anticipate will occur if NEM is reformed and customers hurry to take service on NEM 2.0.

3. Transitioning Customers to the Successor Tariff Is Necessary But Should Be Limited in Duration

Customers should be transitioned to the Reform Tariff promptly after the final decision adopting a new tariff. However, we also understand that this needs to be done in a way that reduces possible adverse impacts to prospective distributed generation customers that could result from too abrupt a change from NEM 2.0 to the Reform Tariff, specifically for those who are already in the process of purchasing solar. Here, we outline an approach to manage the transition while controlling the cost shift associated with new customers taking service on NEM 2.0 promptly.

We recognize that there will need to be some limited transition time between the final decision and ending NEM 2.0 eligibility. The sales cycle for a customer interested in acquiring solar can take several weeks to several months. A transition approach should

[229] PG&E: $505M; SDG&E $158M; SCE $272M.

minimize potential situations where a customer may have made an agreement with a contractor right before NEM is reformed, which then, under the Reform Tariff, may have different financial considerations. To minimize the possibility of this situation, we propose a limited "buffer period" that would allow customers who are in the purchase process, or may be waiting on local permits near the time of the final decision, to submit an application for utility interconnection under NEM 2.0 before the deadline on which the Reform Tariff will take effect. The interconnection application submittal date was chosen as the milestone customers must reach before the deadline because it is the point at which the utilities first receive notification of a customer's intent to install DG technologies and take service on NEM.

A limited buffer period between the final decision and ending NEM 2.0 eligibility for new customers would also allow time for updating customer-facing materials to reflect requirements of the successor tariff. As pointed out by the Solar Energy Industries Association (SEIA) and Vote Solar in their March 15, 2021 Party Proposal, vendors and their supporting providers will need some transition time to revise sales materials, resources, and training for customers based on the successor tariff.[230] We will also update customer-facing educational resources and tools to reflect the structure of the next tariff as described in the next section of this chapter.

We do not propose a specific length of a buffer period between the final decision and ending NEM 2.0 eligibility at this time but will continue to assess an appropriate timing for ending NEM 2.0 eligibility during this proceeding.

4. Legacy Treatment for New NEM 2.0 Customers should be Reduced to Control Cost Shift

To control the cost shift associated with customers who take service on NEM 2.0 during the buffer period describe above, we propose that upon approval of a final decision adopting a successor tariff proposal, 20-years of legacy eligibility treatment on NEM 2.0 will end. After such date, we submit that new distributed generation customers should not be

[230] SEIA/Vote Solar March 15, 2021 NEM Revisit Party Proposal, pp. 38-39.

provided the 20-year legacy period afforded to existing NEM 2.0 customers. Instead, customers who interconnect after the final decision, but before NEM 2.0 enrollment eligibility for new customers ends, should be provided a shorter legacy treatment tied to typical payback for NEM 2.0 customers (for example, 3-7 years, depending on the utility and if storage is included). This will allow customers who may have already entered into an agreement near the final decision to still receive a payback for their investment.

5. <u>New Customers Should Take Service on the Reform Tariff, but Be Initially Billed on NEM 2.0</u>

At the end of this limited buffer period when NEM 2.0 eligibility would end, any new customers who submit applications would take service on the Reform Tariff. On an interim basis, however, these customers would need to be billed on NEM 2.0 until the successor tariff is available in utilities' respective billing systems.

We suggest that NEM 2.0 eligibility should end well before the Reform Tariff can be operationalized in our billing systems, which may take 12-24 months. The resulting continued cost shift that would result if customers remained NEM 2.0-eligible during this time is wholly inconsistent with equity and affordability goals and untenable. In a 12-month period after the Final Decision (assuming it is issued in January 2022), we estimate that $11.2 billion[231] of additional nominal cost shift would be locked-in over 20 years if customers were able to take service on NEM 2.0 during this period with current legacy treatment. This would exacerbate the equity and affordability issues already caused by the current unsustainable cost shift across the three utilities. We note that the 12-13 month transition period between the final decision and the end of NEM 2.0 eligibility proposed by SEIA and Vote Solar would lock-in a comparably unsustainable level of continued cost shift.[232]

[231] Chapter III describes the NEM cost shift and calculation methodologies in detail. This incremental cost shift is calculated based on current NEM 2.0 adoption projections and does not take into account additional cost shift that may be created by a "gold rush" scenario, *i.e.*, a spike in interconnection applications prior to closure of the NEM 2.0 tariff to new customers.

[232] SEIA/Vote Solar March 15, 2021 Party Proposal, page 40.

We therefore propose that customers who interconnect after NEM 2.0 eligibility ends should be temporarily billed on NEM 2.0 and then transitioned to the Reform Tariff once it is operationalized.[233]

6. Approach for Transitioning from NEM 2.0 to Reform Tariff

The utilities' recommended transition approach is summarized in Table VI-42 below, which shows what tariff treatment customers would receive based on the timing of when they submit an interconnection application. Customers who submit applications for interconnection of NEM-eligible technologies before the Final Decision, would take service under the current NEM 2.0 tariff. New customers who submit applications during the "buffer period" between the Final Decision and the deadline for ending NEM 2.0 would take service on NEM 2.0, but with reduced legacy treatment. Any new customers who submit an application for interconnection after the NEM 2.0 eligibility period ends, but before the Reform Tariff is available in the utility billing systems, would take service on NEM 2.0 temporarily, and then be transitioned to the new tariff once the tariff is operationalized. Once the Reform Tariff is operationalized, new customers would take service on it immediately. This approach allows for a buffer between the Final Decision and NEM 2.0 eligibility ending, while also controlling additional NEM 2.0 cost shift.

[233] And once their NEM 2.0 annual True-Up cycle or "relevant period" has ended.

Table VI-42
Recommended Transition Phases

	Time Period in which Interconnection Application is Submitted	Change to Tariff Treatment
a.	Before final decision	None, customers would remain on NEM 2.0 with current legacy treatment (20 years)
b.	After final decision, before TBD deadline to end NEM 2.0 eligibility	New customers who submit interconnection application after final decision, but before NEM 2.0 eligibility ends, have abbreviated legacy treatment (years of eligibility for staying on NEM 2.0) that is tied to payback for respective IOUs (3-7 years).
c.	After NEM 2.0 eligibility deadline, before the Reform Tariff is available in IOU billing systems	Customers take service on the Reform Tariff, but are billed temporarily on NEM 2.0 until the Reform Tariff is operationalized in IOU billing systems
d.	After the Reform Tariff is operationalized in IOU billing systems	Customers take service on, and billed on, the Reform Tariff

7. Solar Consumer Protection Information Packet Should be Updated to Indicate NEM is Changing

To further facilitate customer awareness of pending changes to Net Energy Metering in the months leading up to a final decision on NEM reform, we request that the CPUC update the California Solar Consumer Protection Guide to inform prospective distributed generation customers that NEM will be changing in 2022. This update should occur as soon as possible and by no later than November 1, 2021. This would help customers who may be on the cusp of entering into contracts before the deadline for ending NEM 2.0 eligibility consider whether their technology choices and contract terms will still be favorable under a revised tariff.

C. Marketing, Education and Outreach

The Joint Utilities recognize the need to raise customer awareness about the successor tariff so that customers can make informed choices about investing in DG technologies.

Empowering customers to understand NEM changes is a key component of consumer protection. To this end, we plan to conduct Marketing, Education, and Outreach activities to provide customers and vendors information on the next tariff. In this section, we outline key ME&O strategies to help raise customer and vendor understanding of the Reform Tariff established through this proceeding. ME&O strategies may be adjusted to accommodate the tariff structure that the Commission ultimately adopts.

Key changes in our proposed Reform Tariff and proposed revised residential default rates that would be addressed through ME&O activities including:

- Explaining the shift from an annual to a monthly true-up, netting within TOU intervals, and how seasonality in solar generation can impact customer bills throughout the year;
- New otherwise applicable rate requirements for NEM customers; and
- The monthly Grid Benefits Charge and what that charge covers (including the Low-Income Discount).

In our outreach strategies, we will consider the needs of specific customer segments, including customers with non-English language needs, to drive awareness throughout the customer journey. We will also leverage multiple communication channels to ensure changes are communicated to as broad an audience as is practicable.

Our outreach plan will also include strategies to support vendors with information they need to manage NEM changes for their sales and customer support activities.

1. <u>Key Customer Segments</u>

ME&O activities will be targeted toward specific customer segments based on where customers are in their experience in taking service on NEM or the Reform Tariff. Assuming customers are transitioned to the Reform Tariff as outlined above, the utilities' approach to ME&O could be tailored to the following customers:

- Those currently taking service on NEM 1.0 and 2.0

- New Reform Tariff customers who:
  - Request to interconnect on NEM 2.0 after the final decision but before the deadline for NEM 2.0 eligibility, and thus have the proposed abbreviated legacy treatment on NEM 2.0.
  - Request to interconnect after the deadline for NEM 2.0 eligibility, but before the Reform Tariff program is operationalized, and thus will temporarily be billed on NEM 2.0 until the Reform Tariff is operationalized.
  - Are considering taking service on and are being billed on the new Reform Tariff.

Across these customer segments, we will employ strategies to make information available to customers with non-English language needs.

a) NEM 1.0 and NEM 2.0 Customers

Our proposal does not propose changes to the NEM tariffs for existing customers, though other party proposals submitted on March 15, 2021, do. If tariff or programmatic changes are established for existing NEM customers through this proceeding, once the regulatory directives are clear, our outreach plans will need to communicate with existing customers about any changes. For example, if Cal Advocates' proposal is adopted and existing NEM customers are transitioned to the Reform Tariff five years from the date of the final decision, existing NEM 1.0 and 2.0 customers would receive communications prior to the transition to be educated about the change in billing structure.

b) New Customers who Fall Within the Post-Decision Transition Period

We plan to have a specific outreach strategy for new customers who would take service on NEM 2.0 during the transition "buffer period" described in section VI.B. above. We will implement communication strategies to help customers understand:

- When NEM 2.0 eligibility will end;
- What milestones must be reached by a given deadline to qualify for the NEM 2.0 current legacy treatment and an abbreviated legacy treatment; and

- That new NEM customers who submit applications after the NEM 2.0 eligibility deadline will take service on the Reform Tariff once it is operationalized.

Customers who will be transitioned to the Reform Tariff will also receive communications several months prior to their transition Reform Tariff explaining the change in billing structure.

c) <u>New Customers Taking Service on the Reform Tariff</u>

We will update customer-facing information and processes to support DG customers throughout their customer journey based on the requirements of the Reform Tariff that is established through this proceeding. These resources may include online educational resources, direct communications to participating customers, bill presentment, as well as training and reference materials for account representatives and call center representatives.

Key stages in the customer journey, and the associated resources that support customers, include the following:

(1) <u>Exploration</u>

As potential solar customers research their DG technology and vendor options, we will provide information on Reform Tariff and Value of Distributed Energy (VODE) tariff changes within online resources. Providing this information enables customers to better understand solar and storage technologies, the financial benefits and risks of investing in these technologies, and how they will be billed. We will also provide information for California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) program customers and how they might benefit through a lower GBC and storage incentive, as discussed in Chapter 5.

(2) <u>Installation</u>

Incorporating links to online Reform Tariff billing information within the permission to operate communication will further educate customers on what to expect in advance of their first bill.

(3) Billing

After a customer interconnects their solar, storage, or other DG technology, we will provide customers with solar-specific information designed to educate customers about Reform Tariff billing. For example, customers will need to understand how their bill charges may vary from month to month based on solar system generation (*i.e.* summer generating more, winter generating less). In addition, helping customers understand what they are being charged for, and what those charges cover, promotes a better customer experience.

d) Customers with Non-English Language Needs

Across the customer segments outlined above, we will make resources available in key non-English languages represented in our respective service areas to the greatest extent feasible.

2. Solar Industry Stakeholders

We will consult with DG industry stakeholders to update contractor-facing utility resources and to support solar vendor understanding about the new tariffs, interconnection, billing, and other elements of the DG customer and contractor journey.

3. ME&O Channels

We will utilize a variety of communication channels to raise awareness of changes related to the Reform Tariff. Outreach activities will drive customers and vendors to online resources for each utility. The Commission's Solar Consumer Protection Guide[234] will also be prominently featured online by each utility.

Communication tactics will vary depending on the targeted customer class. While resources and potential channels vary across utilities, possible outreach channels to communicate with existing and potential DG customers, as well as industry stakeholders include:

- Direct communications by letter or email
- Online text, graphics, and videos

[234] https://www.cpuc.ca.gov/solarguide/.

- Online tools such as solar calculators
- Webinars
- Bill messages/inserts
- Call centers; and
- Assigned account representatives

We will seek ways to engage Community Based Organizations to communicate with customers for whom the above strategies may not be preferred. We will also explore opportunities to leverage resources and relationships developed by statewide income-qualified solar incentive program administrators such as Grid Alternatives and the Center for Sustainable Energy to raise customer awareness about changes to NEM.

D. <u>Consumer Protection Considerations</u>

We appreciate and support the Commission's attention on consumer protection for utility customers who invest in DG and storage and take service on Net Energy Metering tariffs. As stated in D.21-02-007, "the Commission should consider how potential successors may support or inform consumer protections".

To provide context for what existing consumer protection measures have been instituted by the CPUC and other agencies, we in this section first review existing measures. We then recommend updates to the California Solar Consumer Protection Guide. Finally, we outline how key design elements of our proposed Reform Tariff and VODE tariff will enhance consumer protection by facilitating greater billing transparency and customer understanding. We see customer understanding of DER tariffs as an important component of consumer protection. Solar and storage investments represent significant expenditures that will have on-going impacts on customer bills under the new tariffs. Better customer understanding of these tariffs can help customers make better decisions related to their solar and storage investments.

1. Existing Consumer Protection Activities

We have supported, and will continue to support, efforts by the CPUC, California State Licensing Board (CSLB), the Department of Financial Protection and Innovation (DFPI), community-based organizations, consumer advocacy groups, and solar industry stakeholders to promote greater consumer protection for solar customers.

Legislation and CPUC directives under the proceeding on enhanced consumer protection measures (R.14-07-002) have instituted key measures. These measures require that solar vendors:

- Obtain signatures attesting customer review of a "California Solar Consumer Protection Guide" developed by the CPUC to help customers review key financial and other considerations before going solar.
- Obtain signatures attesting customer review of a "CSLB Solar Disclosure Form" per AB 1070, Chapter 662, Statutes of 2017.
- Use "Standardized Inputs and Assumptions for Calculating Estimated Electricity Bill Savings from Residential Solar Energy Systems" when providing bill savings estimates provided as part of the solar sales process (also per AB 1070) and D.20-08-001.
- Submit signed copies of the consumer guide, disclosure form, through the IOU interconnection application portals at the time of interconnection, subject to audit, per D.18-09-044, D.20-02-011 and D.20-08-001.
- Submit a valid CSLB license as part of the IOU interconnection process (D.18-09-044).

In addition to the above requirements, D.18-09-044 directs the utilities to track complaints they receive related to solar providers and report those complaints to the CPUC.

2. Updates to Existing Consumer Protection Information

Once the design of the Reform Tariff or other NEM successor tariff is clarified through a final decision, consumer protection documentation will need to be updated to reflect changes under the Reform Tariff, including the California Solar Consumer Protection Guide and Standardized Inputs and Assumptions for solar bill savings estimates. As stated above, we also propose that no later than November 1, 2021, the CPUC update the current Consumer Protection

Guide with a disclaimer that indicates changes to NEM may be instituted in 2022. This will provide a way for customers who may be considering solar on longer sales, contracting, and permitting cycle times to be aware that their bill savings may be different if their system does not make the deadline for NEM 2.0 eligibility described in Section VI.B of this Testimony.

3. Reform Tariff and VODE Tariff Design Elements that will Enhance Consumer Protection

Key design elements of our proposed Reform Tariff will enhance consumer protection. In designing a new tariff, it is important that policy makers and stakeholders balance sometimes conflicting rate design principles: ensuring the design reflects cost-causation, which can add tariff complexity, with facilitating customer understanding, a critical component of consumer protection.

Understanding of NEM billing is important for consumer protection and customer experience, as it enables customers to:

- Assess bill savings projections before they invest in solar;
- Validate bill savings once they have gone solar; and
- Understand how additional load management behavior or technologies will impact their overall electricity costs once they are on a NEM billing structure.

In R.14-07-002 on enhanced consumer protection measures, misunderstanding of both projected and realized bill savings was identified as a consumer protection problem. In D.18-09-044, the CPUC identified a key consumer protection issue raised by parties to the proceeding was "a lack of customer understanding of the factors impacting their actual bill savings, including changes in their energy usage and rate structures underlying the current NEM framework." Furthermore, the CPUC's Rate Design Principles as articulated in D.15-07-001 state that rates should be "understandable." As described further below, our proposal will provide greater transparency to customers and vendors, and will be easier to understand, which can reduce confusion about successor tariff billing and facilitate consumer protection.

a) Monthly True-Ups Will Eliminate Surprising and Challenging Annual Bills

We are proposing to change the true-up period from annual to monthly, as described in Chapter IV. Changing the true-up period from an annual period to a monthly period will reduce unexpectedly high bills some NEM customers face at the end of their annual period, which is a significant pain point for many customers. Under the existing NEM programs, residential and small commercial customers generally pay only minimum or fixed charges on a monthly basis. At the end of their annual true-up period, customers pay the net of their annual consumption charges and export credits, with a Non-Bypassable Charge (NBC) adjustment for NEM 2.0 customers and Net Surplus Compensation adjustments for net exporters.

Customers can end up with large bills at the end of the annual true-up period, the amount of which can be difficult for customers to manage, particularly those with lower incomes. Hearing about high yearly true-up bills from peers may even dissuade some customers from going solar. In PG&E's service area, residential NEM customers are more likely to use PG&E's Payment Arrangement option, which provides customers a payment extension. Compared to customers who are not on NEM, the use of this option is about 70% higher among non-CARE NEM customers and 30% higher among NEM CARE customers, which suggests that some NEM customers have trouble paying their true-up bills (Table VI-43).

Table VI-43
Percent of PG&E Service Agreements that Utilized Payment Arrangement
(March 2020 – February 2021)

	Not on CARE	On CARE
NEM	6.9%	23.3%
Non-NEM	4.0%	18.0%
Percent higher utilization rate among NEM customers (compared to non-NEM)	71.9%	29.0%

b) Standardized Export Compensation Will Facilitate Customer Understanding

A clear standardized compensation rate for solar exports would simplify Reform Tariff billing and improve customers' ability to understand projected and realized bill savings. While customers often rely on analysis from vendors and installers to evaluate the overall cost-effectiveness of systems, many customers want to understand what drives bill savings in order to validate the projected savings before they purchase solar. Customers also often wish to verify that projected savings have in fact materialized after an investment in solar.

Under the current NEM 2.0 structure, estimating and validating bill savings is complicated and confusing for customers. Under NEM 2.0, the amount owed by customers at their annual true-up is in part a function of charges for consumption and credits for exports to the grid, valued at the customers' underlying rate. However, export credits cannot offset charges at true-up below the amount of the customers' total NBCs, which, in effect, changes the value of solar exports. If a customers' net imports from the grid are not coincident with the hours in which solar is generating, and the customer has a larger solar system that is creating significant export credits during the day, then the total amount owed at true-up can be a function of the NBCs, rather than the sum of export credits and consumption charges. This tariff structure was put in place by Decision 16-01-044 in an effort to ensure that a certain minimum of NBCs would be collected from NEM 2.0 customers. However, this structure has significantly complicated what overall bill savings a customer will actually experience and is very difficult for customers to understand. Setting standardized export compensation rates (coupled with collection of NBCs through the Grid Benefits Charge) would ensure that customers pay a reasonable share of NBCs in a much simpler manner. It would make the value of solar exports more transparent and improve customer understanding of potential and realized bill savings under the Reform Tariff. Finally, having a clear price signal of the cost of energy consumed from the grid versus exported to the grid would provide more clarity on how load management behavior or technologies such as storage will affect overall bill savings.

c) <u>The Customer and Grid Benefits Charge Clarify that Customers Still Use the Grid and Should Contribute to Cost Recovery</u>

Solar customers taking service under NEM use the grid at night or at other times when their electric load exceeds their solar system's generation. Also, solar customers use the grid when their solar exports excess generation to the grid to generate NEM credits. Accordingly solar customers are still responsible for paying for the use of the grid. Solar customers are sometimes told by solar contractors that their electric utility bill will be "zero" and then are surprised when they still receive a bill from their respective utility.[235] A default rate with a customer charge and GBC, as described in Chapter 4, would make the fact that solar customers still use the grid, and must pay for grid services, more transparent and understandable for customers, both before they invest in solar and as they navigate solar billing.

d) <u>A VODE Option Would Improve Solar Generation and Gross Load Visibility for Customers</u>

Under the Value of Distributed Energy (VODE) tariff described in Section IV.F., customers would have the option to meter their solar generation and send that information to the utility for billing purposes. This would enable the utilities to provide customers insight not only into their solar generation, but also into customers' gross load (on-site solar consumption plus usage from the grid).

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[235] Based on review of customer calls to PG&E's Solar Customer Service Center.

Under current NEM structures, customers do not have access to solar generation data through utility bills or customer education tools, because the utilities do not have access to metered solar generation data. Customers often want to see the full picture of their total usage, inclusive of what part of their onsite usage was met through solar generation. Customers often also want to understand what their bill would have been without solar, which utilities do not have the information to provide without metered solar generation data.[236] Greater visibility into how total usage, coupled with solar generation, impacts their overall electric costs, would also enable customers to better manage costs through load management behaviors or technologies.

E. <u>Revenue Allocation and Cost Recovery</u>

1. <u>Cost Recovery of Income Qualified Discount, STORE Program, Implementation, and ME&O</u>

a) <u>Introduction</u>

In this section we discuss the cost allocation and cost recovery for new subsidies emerging from our IQD and STORE proposals, as well as incremental cost for implementation and ME&O. Our cost allocation and recovery proposals are consistent with the principles established through D.21-02-007 and the D.15-01-007 RDPs discussed earlier in Chapter 4. Overall, our Reform Tariff structure results in a meaningful reduction of the cost shift. This reduction is achieved through a tariff structure that properly values standalone solar and paired storage based on each technology's cost of service and value delivered to the grid, while expanding participation in underserved communities through the IQD and the STORE program.

2. <u>Guiding Principles – Proposal for Cost Allocation and Rate Recovery</u>

Cost allocation is driven by the nature and purpose of the underlying costs. Our proposal adheres to this basic tenet by allocating costs that are appropriately tied to the appropriate function (*i.e.*, specific to the generation, distribution, or transmission functions), and

[236] *Id.*

allocating other costs associated with larger societal goals on a broader non-functionalized basis. In this way, our proposal is consistent with the principles established on D.21-02-007 and D.15-01-007 listed here.

NEM Reform Tariff Principles from D.21-02-007:

1. A successor to the net energy metering tariff should ensure equity among customers
2. A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities.
3. Rate Design Principles from D.15-01-007:
4. Rates should be based on cost-causation principles
5. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals

Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates and minimizes and appropriately considers the bill impacts associated with such transitions.

Our NEM Reform Tariff proposal produces two categories of costs. The first category results from funding of the IQD and STORE program ("LMI Programs"), where the nature and purpose of the costs are both societal and functional. As described in Chapter 4, the IQD is a benefit available to CARE and FERA customers, with the purpose of making solar applications more affordable to this segment. From this perspective, cost associated with the IQD serve the broader societal goal of program expansion. The IQD provides a credit to the GBC component of the reform tariff. Here, the utilities provide a discount on the delivery and generation portions of the GBC to bundled customers, and only on the delivery portion for unbundled customers. From this perspective, the discount is a functionalized cost recoverable from bundled and unbundled customers based on the costs responsibilities and services attributed to each group. The STORE program similarly expands access to an underserved segment with storage devices that can serve as a generation capacity resource, introducing a functional element to the nature of costs and benefits associated with STORE. We have not fully explored the contractual relationships and implications of a single capacity resource assigned to multiple LSEs. At this stage, our proposal does not define STORE eligibility between bundled and unbundled customers. This determination, in addition to the exact allocation and cost recovery mechanism, will be developed as the program is further defined, potentially through a workshop process.

When there are competing objectives between principles, such as exists between the principle of cost causation and the principle of subsidies in support of a greater societal good, an allocation based on contribution to system revenue with recovery through PPP charges, strikes an appropriate balance between strict cost causation allocation and the socialization of costs in recognition of a greater societal benefit. A system revenue-based allocation reflects the aggregation of prescribed functional cost allocators (generation, distribution, and transmission) while ensuring that program costs are more broadly socialized. Recovery through PPP charges, ensures the same cost recovery from bundled and unbundled customers, and to some degree from customer groups who participate in the programs. In this way, a contribution to system revenue-based allocator with PPP charge recovery balances the principle of cost causation by marginally adjusting individual group allocations to appropriately reflect how public purpose programs influence utility revenue requirements based on the drivers of cost. The following describes our allocation and recovery proposal for LMI Program costs.

3. <u>Income Qualified Discount</u>

We request that the Commission authorize the Utilities to establish new or utilize existing two-way balancing account(s) to record and recover the revenue shortfall. The generation[237] portion of the rider will be allocated based on bundled generation marginal costs and recovered annually through bundled generation rates. The delivery portion will be allocated based on contribution to system revenues and recovered annually through the PPP charge rate component. We believe that two-way balancing account treatment is appropriate to recover the

[237] Generation refers to providing the electric commodity to electric bundled residential customers.

revenue shortfall since the amount of the discount as well as the criteria used to determine customer eligibility will have been set by the Commission when it issues the final decision on this matter. Additionally, we believe the rate design is equitable to bundled and unbundled customers such that the revenue shortfall related to the services provided to each customer group are recovered from that customer group. The Utilities will file a Tier 1 advice letter to establish new balancing account(s) or, if necessary, modify existing balancing account(s) to record and recover the revenue shortfall.

4. STORE Program:

Once the STORE program has been fully defined, the Utilities request the Commission authorize us to establish a new or utilize an existing balancing account to record the related costs for the STORE Program. The utilities will present a forecast of the total expenses and the related revenue requirement for the program in a Tier 2 advice letter filing. Upon Commission approval of that advice letter, the actual expenses incurred up to the adopted amounts will be recorded to the balancing account. Costs will be allocated based on contribution to system revenues and, or a functional basis depending on how the program's attributes and costs are divided among the LSEs offering the program. This proposed one-way balancing account treatment is appropriate in situations like this where (1) the Utilities are performing necessary work to better serve its customers in the ordinary course of business, (2) the Utilities are able to develop a reasonable forecast for the cost of the work to be performed, and (3) parties will have an opportunity to review the proposed scope of the necessary work and the associated forecasted costs through the advice letter process before any costs are recorded to the balancing account. Adopting balancing account treatment that caps the adopted budget that the Utilities may spend and the authorized revenue that the Utilities may collect from customers without further reasonableness review is an appropriate method of controlling costs and allows the Commission and stakeholders to understand the full costs of the program in a comprehensive manner. Additionally, we would be authorized under this proposal to record into either (1) a separate a memorandum (memo) account or (2) a separate subaccount or tracking account within the one-way balancing account any costs for the STORE Program in excess of the adopted amounts and seek recovery of these costs through the filing of an application and subject to a reasonableness review of those incremental costs above the originally authorized revenue requirement. The Utilities will include in the advice letter the establishment of a new balancing account or, if necessary, a modification to existing balancing account(s) to record and recover the storage program costs up to the adopted amounts.

5. Implementation & ME&O

The second category of costs includes those associated with implementation and delivery of new tariffed options. This category of costs will be allocated based on distribution marginal costs and recovered through distribution rates. The incremental activities associated with ME&O and implementation arehe same in nature and purpose as standard customer care and implementation activities in the provision of electric service normally presented and litigated in a GRC Phase 1. In this case, these costs are being presented separately as the respective GRC Phase 1 proceedings are out of phase with the NEM reform proceeding. Prior to implementation of the NEM Reform Tariff, we expect to file an appropriately designated Advice Letter, which among other things would establish a memorandum account for implementation costs and reiterate the revenue recovery mechanism.

We request that the Commission authorize that the actual incremental expenses and the capital revenue requirement associated with the actual incremental capital expenditures related to implementation and ME&O be tracked and recorded in a new memo account. Disposition of the balances in this account would be addressed in a future General Rate Case (GRC) or other application or proceeding, subject to the Commission's review and approval of reasonableness. Upon approval, the IOUs would transfer the balances to the appropriate electric balancing account(s), as may be directed by the Commission, for recovery in distribution rates through the next annual electric rate true-up. Memo accounts are appropriate in situations such as this one when a utility is unable to make a forecast, or when a utility has not made the forecast available for review by parties prior to cost recovery.

a) **PG&E**

PG&E supports the proposed cost control, allocation, and recovery for costs described above. Further, PG&E clarifies that recovery through and true-up of PPP, generation, and distribution rates as previously described above would be through its Annual Electric True-up (AET) advice letter process.

b) **San Diego Gas and Electric**

SDG&E supports the proposed cost control, allocation, and recovery for costs described above. Further, SDG&E clarifies that recovery through and true-up of PPP, generation, and distribution rates as previously described above would be through its Annual Consolidated Rate Change Advice Filing.

c) **Southern California Edison**

SCE supports the proposed cost control, allocation, and recovery for costs described above. Further, SCE clarifies that recovery through and true-up of PPP, generation, and distribution rates as previously described above would be through its Annual Consolidated Rate Change Advice Filing.

VII.

ASSESSMENT OF THE JOINT UTILITIES' PROPOSED REFORM TARIFF AGAINST CERTAIN CRITERIA

A. Proposed Reform Tariff Summary and Overview

The Joint Utilities' proposed Reform Tariff offers the Commission a compelling option for transitioning to the next chapter of distributed generation compensation in California. The proposal balances support for customers' adoption of rooftop solar and other distributed energy resources while ensuring just and reasonable rates for all the Joint Utilities' electricity customers.

As described in Chapters IV and V, the Joint Utilities' proposal is designed to replace the existing net metering tariff with a net billing structure with default cost-based rates, where all energy delivered to the customer is billed at the retail rate, and all energy exported to the grid is compensated at the export compensation rate. There are four core elements of the proposal package:

- A more cost-based residential default rate for residential customers on the Reform Tariff, including through time-of-use rates for three periods for the summer, and winter seasons.
- A value-based export compensation rate (ECR) decoupled from the retail rate, with the export rate set at the Avoided Cost Calculator values and based on a one-year forward estimate in different time periods when the customer injects supply into the grid and with the rate updated annually.
- A grid benefits charge (GBC) for residential customers and non-residential customers based on solar system size and updated annually, with the GBC designed to recover distribution, transmission, generation, and non-bypassable, and other policy charges less relevant avoided costs.
- The netting of a customer's consumption and exports on an instantaneous basis during time-of-use (TOU) periods, with monthly true-ups.

There are three other key elements of the proposal. First, the proposal anticipates no change in existing NEM 1.0 and NEM 2.0 customers' terms and conditions of service. Second, it offers two provisions targeted to income-qualified customers: (a) An Income-Qualified Discount (IQD) to reduce the GBC for income-qualified customers that adopt solar, in conjunction with export compensation at the full (non-discounted) avoided cost[238] as determined by the Avoided Cost Calculator available to

[238] As discussed in Chapters IV and V.

other Reform Tariff customers; and (b) A pilot program called Savings Through Ongoing Renewable Energy (STORE) to procure behind-the-meter storage for income-qualified customers which will include utility dispatch rights to maximize the value of the generation to the grid while improving the customer's value proposition. Third and finally, it includes revised virtual net energy metering (VNEM) successor tariffs — one applicable to low-income housing and one for customers in other buildings with a VNEM arrangement.

The Joint Utilities' proposed Reform Tariff accomplishes the following:

- Addresses the unsustainable cost shift from participants to non-participants for new distributed generation customers.
- Ensures that new distributed generation customers pay their fair share of transmission, distribution, and public policy costs.
- Fairly compensates new distributed generation customers for the value their electric supply provides to the electric system.
- Allows for sustainable growth of customer-sited renewable generation by enabling customers to install distributed generation to meet their objectives for hedging electricity costs and long-term savings, supplying their own power, reducing emissions from power generation, and back-up power, even if the value proposition is not as generous as in the past.
- Provides income-qualified electricity consumers with equitable (if not more attractive) incentives to adopt solar resources.
- Aligns customers' rates so that they reflect the costs and benefits that their generation provides to the system.
- Supports and aligns with California's goals for increased reliance on renewable energy, greenhouse gas emissions reductions, improvements in air quality, electrification, customer choice, and more equitable access to clean energy by low-income people and disadvantaged communities.

As described in this concluding chapter of the Joint Utilities' opening testimony, their Reform Tariff meets the Guiding Principles adopted in this proceeding. The proposals bring the tariff for residential and other customers into alignment with the Commission's core ratemaking principles of basing rates on the cost of service, affordable electricity, conservation, and customer acceptance. Additionally, as described in Chapter 2, transitioning policy as market conditions change is a hallmark of good policy design.

This concluding chapter compares the provisions of the Joint Utilities' proposal with the Commission's Guiding Principles, its ratemaking principles, and other sound public-policy standards.

B. Alignment of the Proposed Reform Tariff with the Guiding Principles and Other Policy Goals

1. Guiding Principle (a): *A successor to the net energy metering tariff shall comply with the statutory requirements of Public Utilities Code Section 2827.1.*

Section 2827.1: (1) Sustainable growth in customer-sited renewable distributed generation. The Joint Utilities' proposal, if approved, would be implemented in the context of favorable behind-the-meter renewable market conditions, would allow customers to continue to realize bill reductions through the installation of behind-the-meter solar and solar-paired storage, and would prevent unsustainable increases in the cost shift to non-participants. For instance, as described in Chapter I, numerous renewable-energy and distributed-generation policies have been implemented in California in the 25 years since NEM was instituted in the state. All new buildings, for example, will be required to have rooftop solar. Likewise, as discussed in Chapter II, the market for solar has matured in that period as well, with much-broader customer awareness of solar, much-lower costs of rooftop PV and residential battery storage, and more providers are in the market with a wide variety of service offerings. Solar and storage provide an appealing combination, with storage customers looking for resiliency and back-up power more than payback period. Other states that have reformed their distributed-energy tariffs from net metering to net billing have continued to experience growth in customer adoption of rooftop solar. As the Joint Utilities explained in Chapter IV, new distributed generation customers will continue to see bill reductions under the Reform Tariff proposal. Finally, as discussed in Chapter III, without reform of the NEM 2.0 tariff, the existing NEM subsidy would increase from $3.4 billion annually to $10.7 billion annually in 2030 with annual bill impacts to non-CARE non-participating customers of $505 for PG&E, $555 for SDG&E, and $385 for SCE. The Reform Tariff would mitigate these bill impacts by limiting cost shift to (1) existing NEM 1 .0 and NEM 2.0 customers and (2) low-income discounts and programs.

Section 2827.1: (1) Specific alternatives designed for growth among residential customers in disadvantaged communities. As discussed in several chapters of testimony, there are many elements of the Reform Tariff that provide specific options for households in low-income and other disadvantaged communities. Chapters IV and V explain how the proposal spares lower income customers from bearing increasing cost shifts that will occur absent reform. Chapter V discusses the proposed discount on the Grid Benefits Charge for Income-Qualified customers that adopt solar, and the proposal that they receive export compensation at the full (non-discounted) avoided cost available to other Reform Tariff customers. This provides an improved value proposition of these customers relative to other customers. Chapter V also discusses the Joint Utilities' proposal for the STORE pilot, which offers low-income customers the opportunity to install behind-the-meter storage which can be subject to the utility's dispatch control, making the value proposition for solar paired with storage relatively attractive with an improved payback compared to solar alone. This proposed pilot will help these customers manage their electricity bills and take advantage of exporting power when it is most valuable to the system. Likewise, the proposed revised VNEM tariff is applicable to low-income housing, with the credits allocated on an even basis to all customers on the VNEM arrangement. Overall, the proposed Reform Tariff should also be understood in the context of other existing programs that cater to lower income customers, such as Solar on Multifamily Affordable Housing (SOMAH) program, the DAC-Single Family Solar Homes (DAC-SASH) program, the DAC-Green Tariff program, and the Community Solar Green Tariff program. The SOMAH and DAC- SASH programs include up-front incentive funding to lower the costs to participating customers.

Section 2827.1: (2) Establish terms of service and billing rules. Each utility proposes to modify its billing systems and other processes in numerous ways (e.g., interconnection process, bill calculation). The Joint Utilities have proposed implementation steps they will take between a Commission order and the placement of customers fully on to the Reform Tariff. (Chapter 6)

Section 2827.1: (3) & (4) Ensure that the standard tariff made to eligible customer-generators is based on the costs and benefits of the renewable facility, and that the total benefits of the standard tariff to all customers and the system are approximately equal to the total costs. The Joint Utilities' proposal would eliminate the cost shift for all new distributed generation solar only customers, except for low-income customers who would be eligible for a discount on their grid-benefits charge. (Chapters IV, V)

- The proposed tariff is cost based, with export compensation tied to the value of electricity supplied to the grid.

- This is accomplished in the new default residential tariff by the combination of the new Grid Benefits Charge, the compensation for exports at avoided costs and net surplus compensation at wholesale market prices, the time-of-use (TOU) rates combined with the instantaneous netting within each TOU period and the monthly true-up of credits.

- Customers that newly adopt rooftop solar and other distributed generation technologies would pay their share of the costs of maintaining a reliable electric system that depend on when they are purchasing power from the grid and when they are using it to absorb the power they export to others.

- The proposal's incentives for customers to install storage in combination with rooftop solar better align rooftop solar customers' interests with those of the system and its other customers.

- The proposal's reliance on 1-year forward time-differentiated avoided costs (rather than long-term avoided costs), updated annually, as the basis for compensating exports, more closely aligns with a reasonable approximation of (a) the value of exports to the system over the course of a day and a season, and (b) the character of system benefits as they change from one year to the next.

- Similarly, the annual updating of the Grid Benefits Charge will keep it current with system costs.

Section 2827.1: (5) Allow projects greater than 1 MW that do not significantly impact the distribution grid to be built to the size of the onsite load. The Joint Utilities have not yet described how they would address this principle.

Section 2827.1: (6) Establish a transition period. The proposal maintains existing NEM 1.0 and 2.0 legacy periods. These customers would be required to take service on the Reform Tariff at the end of their legacy period. The Joint Utilities have proposed implementation steps they will take between a Commission order and the placement of customers fully on to the Reform Tariff. (Chapter VI)

Section 2827.1: (7) The Commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding… and shall ensure customer generators' rates are just and reasonable. The proposals the Commission is now reviewing are part of a rulemaking proceeding in which the CPUC will determine what tariff structure design will yield just and reasonable rates for customer generators as well as other customers.

Guiding Principle (b): ***A successor to the net energy metering tariff should ensure equity among customers.*** The Joint Utilities' proposal provides equitable treatment for participating and non-participating customers. (Chapters IV and V)

- The standardized compensation for exports, set at the time-differentiated avoided cost, ensures equal compensation for the same generation within different time periods, whether supplied by a behind-the-meter resource or a grid-connected resource. (Chapter IV)
- Export compensation is the same for customers on low-income discount programs such as CARE and customers that are not on low-income discount programs (Chapter V)
- The Grid Benefits Charge provides for the collection of unavoidable and non-bypassable charges from customers adopting behind-the-meter generation.

Guiding Principle (c): ***A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services.*** The Joint Utilities' proposal includes a number of elements to protect consumers, including continuation and updating of customer education materials, greater transparency regarding the costs of providing various aspects of utility service and the value of exports to the grid, and greater connectedness between the timing of electricity consumption and exports and the billing of services related to them. (Chapter IV and VI)

Guiding Principle (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.*** The Joint Utilities' proposal is neutral with regard to different behind-the-meter generation sources. (Chapter VI)

Guiding Principle (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.*** The Joint Utilities' proposal aligns well with California's and the Commission's energy policies (Chapters I and II)

- The proposal will address the fact that the large cost shift makes electricity more expensive for everyone, and thus risks making electrification of building and transportation less attractive. (Chapters I, II and III)
- The proposal will continue to provide consumers with the option to adopt rooftop solar, with or without storage, and to recover the costs of the investment(s) over its life, thus supporting California's goal of decarbonizing the state's electricity supply. (Chapters I and II)
- On new buildings where solar PV systems will be required, and on existing buildings, the proposal will create incentives for paired storage, thus aligning the availability of supply from customers to the grid to times when such supply is most valuable to the energy system. (Chapters I and IV)
- It aligns compensation for exports at avoided costs, which are informed by the IRP process. (Chapter IV)
- It addresses the affordability concerns associated with electricity prices in California. (SB 100) (Chapters I, III, IV, and V)
- It aligns with the Commission's principles for designing just and reasonable rates -- that they be based on the cost of service, affordable, support conservation, and be acceptable to customers. (D.15-01-007) (Chapters I, II, and IV) The proposal aligns with specific policies and processes including:
    - SB 100: The proposal promotes decarbonization at least cost by proposing compensation for behind-the-meter renewables based on the utility's ACC values. The proposal also promotes stable retail rates, another goal of SB 100.
    - IRP: The overall tariff design is informed by utility ACC values, which are an output of the IRP.
    - Title 24: The proposal provides a reasonable value proposition for rooftop solar, consistent with Title 24 mandate for rooftop solar on new construction where cost effective.
    - Executive Order B-55-18: The proposal supports California's carbon-neutrality goals through a design that enables the continued growth of rooftop solar without

compromising other sustainability efforts such as electrification and affordability of utility service.

Guiding Principle (f): ***A successor to the net energy metering tariff should be transparent, understandable to all customers and should be uniform, to the extent possible, across all utilities.*** The Joint Utilities have developed a proposal with common elements across the utilities' tariffs, where possible. (Chapter IV and V)

- The design of the proposed Reform Tariff is more transparent and understandable to customers in that it sends more direct and clear price signals to customers about the continued need to pay for grid services and public programs (through the Grid Benefits Charge). The Reform Tariff also improves transparency regarding the value of solar exports by having standardized export rates (based on ACC values). This will be easier for customers to understand than the current NEM 2.0 structure under which the value of solar exports is tied to the customers' retail rate, with a complex adjustment for non-bypassable charges. (Chapter VI)

- The Joint Utilities' optional Value of Distributed Energy tariff proposal provides greater transparency for customers regarding their overall consumption (including solar generation which serves on site load). Having separate metering of the solar system on the VODE tariff would also provide greater visibility into how total usage, coupled with solar generation, impacts their overall electric costs. This would enable customers to better manage costs through load management behaviors or technologies. Separate solar metering would also facilitate customer's participation in load and or solar generation management programs that may be used to provide grid services. (Chapter VI)

Guiding Principle (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.*** The proposal appropriately prices exports from customer-sited systems at ACC values, thus assuring that the customer generator receives compensation tied to the value of the resource to the system and non-participating customers do not overcompensate customer generators (which would be a transfer of value from non-participants to new solar adopters).

Guiding Principle ***(h): A successor to the net energy metering tariff should consider competitive neutrality amongst Load Serving Entities***. The proposal splits the export compensation rate into two parts: "commodity" and "system" components. This feature is designed to ensure competitive neutrality among load serving entities.

Other public-policy objectives:

A successor should be aligned with the Commission's rate design principles. The Joint Utilities' proposal aligns well with the Commission's 10 ratemaking principles for residential rate design.

1. Low Income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost. (Chapter V)
2. Rates should be based on marginal cost. (Chapter IV)
3. Rates should be based on cost-causation principles (Chapters III and IV)
4. Rates should encourage conservation and energy efficiency (Chapter I)
5. Rates should encourage reduction of both coincident and non-coincident peak demand (Chapters I and IV)
6. Rates should be stable and understandable and provide customer choice (Chapter IV and VI)
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals (Chapters I, II, III, IV and V)
8. Incentives should be explicit and transparent (Chapters II, IV and V)
9. Rates should encourage economically efficient decision making (Chapter IV)
10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions (Chapter VI).

A successor shall transition financial incentives as the market conditions change over time. The Joint Utilities' proposal represents an appropriate evolution in the design of the NEM tariffs since they were first introduced 25 years ago. Now that the industry is more mature, the costs of rooftop solar and residential storage have declined substantially, and the adoption of solar equipment by customers is no longer novel, it is time to modify the structure of this policy.

1. The Joint Utilities' proposal eliminates the subsidy for standalone solar borne by all other customers to enable some customers to adopt rooftop solar, although it provides an incentive (lower than before) for solar paired with storage.

2. The proposal retains incentives for low-income customers most in need.

3. And the compensation rate based on the 1-year levelized avoided cost for each hour, based on the ACC, updated annually avoids reliance on long-term forecasts, and better reflects market conditions as they change over time.

A successor tariff should be open to relying on sources of financial incentives from non-ratepayer-funded sources, where such incentives and subsidies are primarily designed to support broad societal objectives rather than goals directly related to the provision of utility service. The Joint Utilities' proposal does not explicitly address this consideration, but it would not be incompatible with potential future decisions by the California State Legislature to authorize and fund additional incentives for consumers' adoption of rooftop solar.

Appendix A

Witness Qualifications

SAN DIEGO GAS & ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF APRIL BERNHARDT

Q. Please state your name and business address for the record.

A. My name is April Bernhardt. SDG&E employs me as a marketing manager in the company's Corporate Communications and Marketing department. My business address is 8306 Century Park Court, CP-62C, San Diego, California, 92111.

Q. Briefly describe your present responsibilities at San Diego Gas & Electric Company (SDG&E).

A. I have been employed by SDG&E as a communications manager since 2010 with increasing areas of responsibility. As the marketing manager of Pricing Plan Education, I oversee the marketing and communication efforts for Clean Transportation, Demand Response programs, Community Choice Aggregation, Rate Reform, and Net Energy Metering. My responsibilities include developing marketing strategies to increase customer awareness and understanding of the issues mentioned above. Additionally, I am responsible for collaborating with internal and external stakeholders to ensure stakeholders are informed on critical Marketing, Education, and Outreach activities.

Prior to my current role, I served as a senior project manager in communications overseeing executive communications and internal change management for SDG&E. I also served as a senior communications manager in Media and Employee Communications at SDG&E, and previously held management roles in communications at Sempra Energy and Qualcomm Inc.

I have previously served as a witness before the California Public Utilities Commission.

Q. Please summarize your educational and professional background.

A. I graduated from San Diego State University with a Bachelor of Liberal Arts and Science in Psychology. I have more than 17 years of experience working in corporate communications and media relations, and most recently, marketing—my career spans working both in wireless communications and the energy sector.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF COLIN KERRIGAN

Q. Please state your name and business address for the record.

A. My name is Colin Kerrigan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q. Briefly describe your present responsibilities at Pacific Gas and Electric Company (PG&E).

A. My current position at PG&E is Rate Analyst, Principal on the Rate Architecture and Load Forecasting team. I am responsible for preparing and managing the preparation of retail electric rate design proposals for presentation before the California Public Utilities Commission.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science in Environmental Economics and Policy from the University of California, Berkeley in 2011. I joined PG&E in 2011 as an analyst in PG&E's Customer Energy Solutions department, and took on roles of increasing responsibility in this department through 2016. My primary responsibilities included providing analytical support for the various customer programs managed by PG&E, such as Energy Efficiency, Demand Response, Pricing Products, and Distributed Generation. I transitioned to the Energy Procurement and Policy Department in 2017. In this role I developed PG&E positions and strategy regarding the nexus of supply side planning and distributed energy resources. I transitioned to my current role at the start of 2021.

Q. What is the purpose of your testimony?

A. I am sponsoring the following testimony in the Joint Investor-Owned Utilities' Net Energy Metering Successor Tariff OIR proceeding:

Chapter 3, PG&E Cost Shift Estimates for PG&E

Chapter 4, Section H – Proposed Default Residential Rate for Reform Tariff Customers 1 – PG&E

Section I – Export Compensation Rates

Section L - Value of Distributed Energy (VODE) Optional Tariff Section M - Standby Exemption for Non-NEM Solar Generators Under 1 MW Should be Eliminated

Section G - Virtual Net Energy Metering (VNEM) Tariffs

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF BRIAN D. KOPEC

Q. Please state your name and business address for the record.

A. My name is Brian D. Kopec, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am Senior Advisor, Marketing within the Customer Programs and Services division of Southern California Edison. In this role, I am responsible for SCE's marketing communications associated with residential rates.

Q. Please summarize your educational and professional background.

A. I completed a Bachelor's degree in Business Administration from Eastern Michigan University with emphasis in advertising and marketing. I have worked at SCE for approximately 14 years in Customer Service. Prior to my current function which I described above, I was the Manager of Residential Marketing in the Customer Service Programs and Services division for approximately three years. Prior to SCE, I have over 10 years of experience in business working in disciplines such as advertising, marketing, promotion, branding and public relations for a variety of businesses, both consumer package goods and services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to co-sponsor the portions of marketing, education and outreach related testimony identified as assigned to me in Chapter 6.

Q. Was this material prepared by you or under your supervision?

A. Yes it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF REBECCA MADSEN

Q. Please state your name and business address for the record.

A. My name is Rebecca Madsen, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q. Briefly describe your present responsibilities at the Pacific Gas and Electric Company (PG&E).

A. I am an Expert Regulatory Analysis and Forecasting Analyst in PG&E's Energy Accounting Department, within the Controller's organization. In this position, I am responsible for ensuring the recovery of the costs included in cases from customers. I advise on emerging regulatory issues, act as a cost recovery witness for cases, and implement cost recovery requirements in California Public Utilities Commission (CPUC) decisions. I am also responsible for process improvements and documentation of existing processes.

Q. Please summarize your educational and professional background.

A. I earned a Bachelor of Arts degree in Archaeology from the George Washington University and an Associate in Science degree in Accounting from Skyline College. I have been a registered Certified Public Accountant in California (License 118069) since 2013.

I have been with PG&E for over 6 years. During that time, I have worked within the Energy Accounting Department of the Controller's organization, where I was responsible for performing month end close activities, including recording journal entries, reconciling accounts, and performing variance analysis, related mainly to Public Purpose Programs. I was also responsible for reading and interpreting decisions and resolutions issued by the CPUC, understanding the accounting impacts, and recording the related journal entries and preparing the supporting documentation.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring the following prepared testimony in support of the Joint Investor Owned Utilities Opening Testimony in the NEM Successor Tariff proceeding R.20-08-020:

- Chapter VI, Section E. – Revenue Allocation and Cost Recovery -PG&E testimony

Q. Based on information and belief, is your testimony true and correct?

A. Yes, it is.

Q. Does this conclude your qualifications?

A. Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF MELANIE MCCUTCHAN

Q. Please state your name and business address for the record.

A. My name is Melanie McCutchan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q. Briefly describe your present responsibilities at Pacific Gas and Electric Company (PG&E).

A. My current position at PG&E is Supervisor, Product Management for Distributed Generation Programs in the Customer Energy Solutions Department. In this capacity, I manage a team that coordinates implementation of Net Energy Metering tariffs and supports the customer experience for PG&E customers who install Distributed Generation (solar, fuel cells, wind etc.) and storage technologies at their homes or businesses.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Arts degree with a double major in Economics and Environmental Sciences from the University of California at Berkeley, in June 2000. In June 2009, I received a Master's Degree in International Business and Environmental Policy from the University of California at San Diego's Global Policy School (formerly the School of International Relations and Pacific Studies).

I have over ten years of experience working on Distributed Generation (DG) technologies, in areas related to program management, tariffs, product management, and regulatory policy and market analysis, both at PG&E (2013 to present) and previously at the Center for Sustainable Energy (2010-2013). Prior to that, I worked for a clean energy technology startup and as a Research Associate on air quality and energy policy in the binational San Diego/Tijuana region at a non-profit organization.

I joined PG&E in April 2013 as a Senior Business Analyst in Distributed Generation (DG) Programs in the Customer Energy Solutions Department. My responsibilities in this position included DG and billing data management, analysis, and reporting to facilitate efficient business operations, meet regulatory requirements, and improve customer satisfaction. I transitioned to a role as an Expert Policy and Strategy analyst in July 2014, remaining on the same team. In this position, I researched DG customer adoption behavior, and designed and implemented improvements to PG&E's DG generation forecast, an input to company load planning. I also analyzed DG/storage market and policy developments to inform regulatory strategy. In October 2016, I retained the position and responsibilities but moved to PG&E's Grid Integration and Innovation department.

In June 2017, I transitioned to an Expert Product Manager on the DG Programs team in Customer Energy Solutions. In this role, I developed and managed billing and online products to improve the customer experience for PG&E's solar customers. In June 2019, I was promoted to my current position on the DG Programs team as a Supervisor and currently focus on DG tariff implementation and customer experience management.

Q. What is the purpose of your testimony?

A. I am sponsoring the following testimony in the Joint Investor-Owned Utilities' Net Energy Metering Successor Tariff OIR proceeding:

Chapter VI – Implementation, ME&O and Consumer Protection Issues

Section A – Introduction

Section B – Implementation of the Reform Tariff - PG&E Testimony

Section C – Marketing, Education and Outreach (ME&O) - PG&E Testimony

Section D – Consumer Protection

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF EVA MOLNAR

Q. Please state your name and business address for the record.

A. My name is Eva Molnar, and my business address is 1515 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am the Senior Manager of Pricing Implementation, and I have been in this role since March 2016. My responsibilities currently include overseeing the rollout of major rate initiatives, as well as the launch, enhancement, and management of customer energy management tools.

Q. Please summarize your educational and professional background.

A. I graduated from the Wharton School of Business, University of Pennsylvania in 1994 with a Bachelor of Science in Economics. I received my MBA from Pepperdine University in 2006. I have over 20 years of experience with launching programs, products, and rates for a variety of different businesses. I started SCE in 2006 and have worked at SCE for over 15 years in a variety of different positions in Customer Programs & Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to co-sponsor the portions of testimony identified as assigned to me in Chapter 6.

Q. Was this material prepared by you or under your supervision?

A. Yes it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SAN DIEGO GAS & ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF GWENDOLYN MORIEN

Q. Please state your name and business address for the record.

A. My name is Gwendolyn Morien. My business address is 8330 Century Park Court, San Diego, California 92123.

Q. Briefly describe your present responsibilities at San Diego Gas & Electric Company (SDG&E).

A. I have been employed as a Rate Strategy Project Manager in the Rate Strategy & Analysis group of the Customer Pricing Department at San Diego Gas & Electric Company since 2017. My primary responsibilities include the development of rate design in various regulatory filings, cost-of-service studies, and determination of revenue allocation. I began work at SDG&E in 2016 as a Business/Economics Analyst and have held positions of increasing responsibility in the Electric Rates group.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science in Accounting from the State University of New York at Geneseo in 2010 and a Master of International Affairs from the School of Global Policy and Strategy at the University of California, San Diego in 2016. I am a licensed CPA in New York. I have previously testified before the California Public Utilities Commission. I have also submitted testimony to the Federal Energy Regulatory Commission.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF CARLA J. PETERMAN

Q. Please state your name and business address for the record.

A. My name is Carla J. Peterman, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q. Briefly describe your present responsibilities at Pacific Gas and Electric Company (PG&E).

A. I am the Executive Vice President, Corporate Affairs. I am responsible for developing and implementing strategies for all aspects of corporate affairs, including regulatory; federal, state and local government relations; public policy; and charitable giving.

Q. Please summarize your educational and professional background.

A. I joined PG&E in June 2021, from Southern California Edison (SCE), where I had served since October 2019 as Senior Vice President, Strategy and Regulatory Affairs. Prior to my role at SCE and earlier in 2019, I was appointed by Governor Gavin Newsom to chair the Commission on Catastrophic Wildfire Cost and Recovery, which developed recommendations that led to legislation designed to hold utilities accountable for reducing wildfire risk and encourage a financially stable electric industry.

Prior to these roles, I served a six-year term on the California Public Utilities Commission (CPUC) from 2013 to 2018, where I served as the assigned Commissioner to a number of proceedings, including those relating to energy efficiency, alternative transportation, energy storage, the Renewable Portfolio Standard (RPS), Power Charge Indifference Adjustment reform, and general rate cases.

Before joining the CPUC, I served on the California Energy Commission, where I was the lead Commissioner for renewables, transportation, and natural gas. Earlier in my career, I conducted energy policy research at the University of California Energy Institute and the Lawrence Berkeley National Laboratory.

I serve on the external advisory board for Sandia National Laboratories' Energy and Homeland Security Portfolio, and as a member of the Federal Reserve of San Francisco Economic Advisory Council. I have also served on various other boards, including the National Association of

Regulatory Utility Commissioners (NARUC), and NARUC's Energy Resources and Environment Committee (Vice-Chair). I hold a BA from Howard University, a PhD in energy and resources from the University of California, Berkeley, and MS and MBA degrees from Oxford University, where I was a Rhodes Scholar.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring the following testimony in the NEM Successor Tariff proceeding, R.20-08-020:

- Chapter 1, “Background and Introduction”

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SAN DIEGO GAS & ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF ADAM PIERCE

Q. Please state your name and business address for the record.

A. My name is Adam Pierce, and my business address is 8330 Century Park Court, San Diego, California 92123.

Q. Briefly describe your present responsibilities at San Diego Gas & Electric Company (SDG&E).

A. I am the Director of Customer Pricing at SDG&E. My primary responsibilities include managing: the development of rate design in various regulatory filings, rate strategy, cost-of-service studies, determination of revenue allocation, and load forecasting and analysis.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science degree in Business Administration with emphases on Economics and Finance from Saint Louis University in 2007. Upon receiving my Bachelor's degree, I was employed at financial services firms focusing on debt, equity and mergers & acquisitions transactions for energy and power companies. I joined Sempra Energy in 2012 and have held various positions of increasing responsibility at the Sempra family of companies including: Sempra Energy's Corporate Development Department, Sempra Renewables' Financial Analysis Department, and Sempra Energy's Investor Relations Department.

I have not previously testified before the California Public Utilities Commission.

SAN DIEGO GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF PAUL D. THOMAS

Q. Please state your name and business address for the record.

A. My name is Paul D. Thomas. My business address is 8326 Century Park Court, San Diego, California 92123.

Q. Briefly describe your present responsibilities at San Diego Gas and Electric Company (SDG&E).

A. I have been employed as an Operations Strategy Project Manager in SDG&E's Customer Care department since 2019. My primary responsibilities include management of SDG&E's Complaint Resolution Team and the development of strategic initiatives for the Customer Care Centers organization. Both of these roles include a significant focus on the customer satisfaction and the overall customer experience. Prior to my current role, I began work at SDG&E in 2017 as a Senior Energy Programs Advisor and have more than 16 years of progressively responsible design, development, planning, analysis, management and implementation of energy and water projects and programs for regulated energy utilities (gas and electric) in southern California, both as an employee of the energy utilities, and as a strategic planning consultant.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science in Business Administration from the California State Polytechnic University, Pomona and am both a Certified Energy Manager (CEM) and Certified Demand Side Management (CDSM) Professional as certified through the Association of Energy Engineers (AEE).

Q. What is the purpose of your testimony in this proceeding?

A. I am co-sponsoring the following testimony in the Joint Investor-Owned Utilities' Net Energy Metering Successor Tariff OIR proceeding: Chapter 6, Section B.

I have not previously testified before the California Public Utilities Commission.

SOUTHERN CALIFORNIA EDISON COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF ROBERT A. THOMAS, P.E.

Q. Please state your name and business address for the record.

A. My name is Robert Thomas, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am Director of the Pricing Design, Load Research, and Forecasting Groups in the Regulatory Affairs Department at Southern California Edison Company. In this position, I am responsible for development of SCE's rate designs. I have held this position since September 2019.

Q. Please summarize your educational and professional background.

A. I hold a Bachelor of Science and Engineering from the University of Arizona, a Masters in Business Administration from California State Polytechnic University, Pomona and a Professional Engineering License in Mechanical Engineering.

Prior to my present position, my responsibilities have included Principle Manager of Pricing Design, Marginal Cost, Sales Forecasting, and Revenue Reporting, within State Regulatory Operations. I was responsible for the development of pricing designs and the underlying cost of service studies, including sales forecasting. Prior to this position, I held the position of Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was the SCE's Program Manager for the Self Generation Incentive Program. In this position, I was responsible for all aspects of the program to include dispute resolution, processing applications, program promotion and was SCE's lead representative on the Working Group.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to co-sponsor or sponsor the portions of testimony discussing cost impact of the current NEM structure, rate design, revenue allocation, and cost recovery.

These include:

1) Chapter 3 – Cost impact of the current NEM structure.

2) Chapter 4 – SCE underlying base rate design and Reform Tariff rate design related items specific to SCE.

3) Chapter 6 – Revenue allocation and cost recovery.

Q. Was this material prepared by you or under your supervision?

A. Yes it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

ANALYSIS GROUP, INC.

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF SUSAN F. TIERNEY, PH.D.

ON BEHALF OF THE JOINT UTILITIES

Q. Please state your name and business address for the record.

A. My name is Susan Tierney, and my business address is 1900 16th Street, Suite 1100, Denver, Colorado, 80202.

Q. Briefly describe your present responsibilities at Analysis Group.

A. I am currently a Senior Advisor at Analysis Group, Inc. My current responsibilities include leading consulting engagements, writing reports and white papers, and serving as an expert witness on matters relating to economics, policy and regulation in the electric and natural gas industries.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor's degree from Scripps College, and a Master's degree and Ph.D. in Regional Planning from Cornell University. After my graduate studies, I served in government for 13 years: My last position in government was as the Assistant Secretary for Policy at the U.S. Department of Energy. Before that, I was the Secretary of Environmental Affairs in Massachusetts, Commissioner at the Massachusetts Department of Public Utilities, Chairman of the Board of the Massachusetts Water Resources Authority, and Executive Director of the Massachusetts Energy Facilities Siting Council. Since leaving government in the mid-1990s, I have consulted to businesses, federal and state governments, tribes, environmental groups, foundations, and other organizations on energy markets, economic and environmental regulation and strategy, and energy projects. I have authored numerous articles and reports and have served on three National Academy of Sciences committees: The Future of Electric Power in the U.S.; Accelerating Decarbonization in the United States (an ongoing committee): and Enhancing the Resilience of the Nation's Electric Power Transmission and Distribution System. I serve on several boards and advisory committees, including chairing the Board of ClimateWorks Foundation and the Board of Resources for the Future, serving as a trustee of the Barr Foundation and a director of World Resources Institute and the Energy Foundation. I am a member of the advisory councils of Columbia University's Center for Global Energy Policy, New York University's Institute for Policy Integrity Institute, Duke University's Nicholas Institute for Environmental Policy Solutions, and the New York Independent System Operator (NYISO). I chair the External Advisory Council of the National Renewable Energy Laboratory (NREL) and recently chaired the Department of Energy's Electricity Advisory Committee. I was co-lead author of the energy chapter of the National Climate Assessment. I was a Visiting Fellow in Policy Practice at the University of Chicago's Energy Policy Institute and taught at the Department of Urban Studies and Planning at MIT and at the University of California at Irvine, and have lectured at Harvard University, Yale University, New York University, Tufts University, Northwestern University, University of Chicago, and University of Michigan. I received NARUC's Mary Kilmarx Award in 2015, and in 2020 was designated as a National Associate of the National Research Council of the Academies of Sciences, Engineering and Medicine.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Chapters II, , and VII of the Joint Utilities' opening testimony.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF SAMUEL WRAY

Q. Please state your name and business address for the record.

A. My name is Samuel Wray, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q. Briefly describe your present responsibilities at Pacific Gas and Electric Company (PG&E).

A. My current position at PG&E is Strategic Analyst, Principal on the Customer Choice Policy team. I am responsible for analyzing methodologies and policies related to demand-side resource evaluation in the Integration of Distributed Energy Resources (IDER) proceeding, including evaluation of avoided costs and cost-effectiveness methodologies and tools.

I formerly served as Expert Load Forecasting Analyst in the Rates and Regulatory Analytics Department within the Regulatory Affairs organization. In this capacity, I was responsible for the development of electric sales and customer forecasts.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Arts degree in Economics with a minor in Statistics from the University of Nevada, Reno in December 2008. From 2009-2013, I worked in the legal field as a Litigation and Research Assistant at a firm in Reno, Nevada specializing in civil litigation. My primary responsibilities included legal precedent research, discovery document review and analysis, drafting and editing motion arguments, and client communication.

Concurrent to my work in the legal field, I received a Master of Science degree in Economics in 2013. During my studies, I interned with the Nevada Department of Taxation as a Tax Revenue Forecaster. In this capacity, I developed econometric models to forecast the state of Nevada's general fund tax revenue for the 2013-2015 biennium.

I joined PG&E in 2014 as a Revenue Requirements Analyst in the General Rate Case (GRC) and Regulatory Operations Department. My responsibilities included revenue requirement and cost analysis of Administrative and General (A&G) expense forecasts in PG&E's 2014 and 2017 GRCs. Additionally, I served as a Witness Assistant for the A&G area in the Transmission Owner (TO) 16 rate case. I transitioned to the load forecasting department in September 2015, and in this capacity, I was responsible for developing PG&E's annual electric sales and customer forecasts. In addition to witness responsibilities in the 2017-2019 Energy Resource Recovery

Account forecast proceedings, I served as witness for the TO 18 rate case and testified at the Federal Energy Regulatory Commission on PG&E's load forecast practices. In 2018, I transitioned to my current role, where I've focused on cost-effectiveness and valuation methodologies for demand-side resources.

Q. What is the purpose of your testimony?

A. I am sponsoring the following testimony in the Joint Investor-Owned Utilities' Net Energy Metering Successor Tariff OIR proceeding:

Chapter 3, "Evaluation of NEM Participation Cost Impacts on other Retail Electricity Customers": Section C1 through C5, "Standard Practice Manual Section"

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS AND PREPARED TESTIMONY

OF MARIL WRIGHT

Q. Please state your name and business address for the record.

A. My name is Maril Wright, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q. Briefly describe your present responsibilities at Pacific Gas and Electric Company (PG&E).

A. As Senior Director of Customer Energy Solutions, I am responsible for oversight of PG&E's Income Qualified, Clean Energy Transportation, Customer Resiliency, Demand response, Distributed Generation, and Energy Efficiency programs.

Previously, I served as Director of Pricing Products, where I was responsible for defining and implementing how customers experience our pricing programs, such as: Time-of-Use (TOU), California Alternate Rates for Energy (CARE), other rate plan offerings, and Advanced Metering Infrastructure (AMI) enabled pricing services and tools. In addition, I oversaw PG&E's Energy Savings Assistance (ESA) Program.

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science degree in Engineering from California Polytechnic State University, San Luis Obispo in 1990. From 1990 1998, I worked as a management consultant for PricewaterhouseCoopers LLP (now owned by IBM) in San Francisco where I primarily focused on the utility and transportation industries. In 1998, I joined Proxicom Consulting in San Francisco as Account Manager for utility clients. While at Proxicom, I was promoted to Regional Director for the Western Region consulting offices. In 2000, I transitioned to Vice President for North American Operations for Proxicom (later acquired by Dimension Data). In 2003, I joined Primitive Logic as a Director for Consulting Services. From 2004 2008, I joined Wells Fargo as Vice President for Wholesale Banking.

In 2008, I joined PG&E in the Customer Care Division, Customer Energy Solutions group. The Customer Energy Solutions group is responsible for designing, implementing and administering customer demand side management programs; including energy efficiency, distributed generation, demand response, and rate programs that help PG&E customers in northern and central California manage the energy use of their homes and businesses, which also results in positive environmental impacts and cost savings. My first role was manager of Energy Efficiency Government and Statewide Partnerships. In December 2011, I was promoted to Director, Chief of Staff for the Vice President of Customer Energy Solutions. In 2013, I transitioned to Director of Energy Efficiency Products and Programs where I was responsible for the residential, commercial, industrial agricultural, codes and standards, emerging technologies, information / behavioral products, and engineering programs. In 2014, I transitioned to Director of Pricing Products where I was responsible for implementing how customers experience our pricing programs as well as other AMI enabled pricing services. In my current role overseeing Customer Energy Solutions, I am responsible for overseeing program design, implementation, quality delivery, and cross-functional integration among programs.

Q. What is the purpose of your testimony?

A. I am sponsoring the following testimony in the Joint Investor-Owned Utilities' Net Energy Metering Successor Tariff OIR: Chapter 5, "Income-Qualified Proposals and Savings Through Ongoing Renewable Energy (STORE) Proposal."

Q. Does this conclude your statement of qualifications?

A. Yes, it does.

Appendix B

A Review of Net Metering Reforms Across Select U.S. Jurisdictions

Prepared for Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison Company

(North Carolina Clean Energy Technology Center, February 2021)

A Review of Net Metering Reforms Across Select U.S. Jurisdictions

Prepared for: Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison

Prepared by: North Carolina Clean Energy Technology Center at North Carolina State University

February 2021

About the NC Clean Energy Technology Center

The NC Clean Energy Technology Center, located within the College of Engineering at North Carolina State University, was founded in December 1987 as the North Carolina Solar Center. For the last 30 years, the Center has worked closely with partners in government, industry, academia, and the non-profit community while evolving to include a greater geographic scope and array of clean energy technologies. As a result of this evolution, the Center has grown into a state agency respected for its assistance to the burgeoning "clean tech" sector in North Carolina, as well as one of the premier clean energy centers of knowledge in the United States.

The Center provides services to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, we envision and seek to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy, and mitigating the environmental impacts of fossil fuel use. Since 1995, the Center has managed the Database of State Incentives for Renewables and Efficiency (DSIRE), which is the most comprehensive public source of information on incentives and policies that support renewable energy and energy efficiency in the United States.

The Center is funded through a combination of North Carolina state appropriations (FY19-20 – 21%), federal and other grants (FY19-20 – 67%), and independent fee-for-service research and analysis work (FY19-20 – 11%).

Prepared for: *Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison*

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Executive Summary

The purpose of this study is to examine the key features of net metering tariffs and successor programs in several U.S. utility territories, including Arizona Public Service, Los Angeles Department of Water and Power, PacifiCorp, Sacramento Municipal Utility District, Hawaiian Electric Company, NV Energy, National Grid, and Duke Energy. The key elements of each utility's distributed generation (DG) compensation program (or proposed program, in the case of Duke Energy) are summarized in Table 1. States and utilities are taking a variety of approaches to net metering successor tariff development, as can be seen in the examples discussed.

Table 1. Summary of Net Metering or DG Tariff Structures

Utility	Netting Interval	Export Credit Rate	Net Excess Generation	Additional Fees
Arizona Public Service	Instantaneous	Phasing down to avoided cost; current rate is $0.1045 per kWh	Carries forward indefinitely or paid out	DG Grid Access Fee or On-Peak Demand Charge
LADWP	Monthly	Retail rate	Carries forward indefinitely	None
PacifiCorp (CA)	Instantaneous	Time-varying: On-Peak: $0.04865/kWh Off-Peak: $0.03699/kWh	Carries forward, but expires at end of annual period	None
SMUD	Monthly	Retail rate	Carries forward indefinitely or paid out at special rate	None
HECO Utilities (CGS+)	Instantaneous	$0.1008/kWh to $0.2080/kWh (varies by island)	Carried forward and reconciled at export rate at end of annual period	None
HECO Utilities (Smart Export)	Instantaneous	$0.11/kWh to $0.2079/kWh (varies by island; exports only allowed 4pm – 9am	Carries forward and expires at end of annual period with no compensation	None
NV Energy	Monthly	Retail rate	Carries forward indefinitely	None
National Grid (NY) (Mass Market)	Monthly	Retail rate	Carries forward indefinitely	Customer Benefit Contribution (starting in 2022)
National Grid (NY) (VDER)	Hourly	Value of DER rate	Carries forward indefinitely	50% of Customer Benefit Contribution (starting in 2022)
Duke Energy (SC) - *Proposed*	Monthly, by TOU period	Time-varying: Critical Peak: $0.25/kWh On-Peak: $0.151760-$0.15843/kWh Off-Peak: $0.087586-$0.09529/kWh Super Off-Peak: $0.060268-$0.06994/kWh	Credited at avoided cost rate	Minimum Bill, Increased Basic Facilities Charge, Non-Bypassable Charge, Grid Access Fee

This study also analyzed the payback period for a 5 kW residential customer-owned solar photovoltaic system under the tariff structures noted in Table 1 and identified the current and historic levels of installed net-metered capacity in each jurisdiction. The payback period analyses were completed using the National Renewable Energy Laboratory's System Advisor Model to estimate the simple payback using a 20-year analysis period.

System cost data comes primarily from online solar marketplace EnergySage (ES) (2020 median prices by state) and Lawrence Berkeley National Laboratory's Tracking the Sun (TTS) report.[1] The analysis assumes that the 26% federal investment tax credit is used, as well as any currently available state or utility incentives. Customer electric load data comes from OpenEI and uses low, base, and high load cases.

Table 2. Summary of Simple Payback Period and Installed Capacity Analysis

Utility	Payback Period – ES Base Case (Yrs)	Payback Period – TTS Base Case (Yrs)	Nov. 2020 Installed Resi. NEM PV (MW)	Nov. 2020 Installed C&I NEM PV (MW)	Resi. NEM % 2019 Peak Demand	Total NEM % 2019 Peak Demand	% Resi. NEM Customer Participation
APS	9.6	14.4	940.53	301.89	13.2%	17.5%	10.2%
PacifiCorp (CA)	>20	>20	4.19	5.01	**	**	1.5%
LADWP (Zone 1)	6.6	8.9	270.61	115.91	4.8%	6.9%	3.7%
LADWP (Zone 2)	7.1	9.6	270.61	115.91	4.8%	6.9%	3.7%
SMUD	12.9	17.3	144.38	97.82	4.9%	8.3%	5.8%
HECO Utilities – CGS+	6.0*		405.59	112.78	25.6%	32.7%	16.0%
HECO Utilities – Smart Export	9.0*		405.59	112.78	25.6%	32.7%	16.0%
NV Energy	11.6	18.5	413.38	78.07	5.6%	6.6%	5.3%
National Grid (NY) – Mass Market	11.3	14.1	142.61	277.27	2.5%	7.2%	1.5%
Duke Energy (SC)	19.3	N/A*	75.58	32.64	**	**	1.4%

* Cost data for Hawaii is unavailable from EnergySage and Tracking the Sun. The Hawaii analysis uses average system cost data from SolarReviews. Tracking the Sun does not include cost data for South Carolina.

** EIA does not include peak demand data specifically for PacifiCorp's California service territory and Duke Energy's South Carolina service territory.

The study also examined residential solar adoption rates before and after major net metering reforms, using data from the U.S Energy Information Administration's Form 861-M. Table 3 compares the average monthly residential net-metered capacity additions in the 12 months prior to a net metering reform taking effect to the additions in the 12 months following the reform. These figures suggest that net metering reforms may have had a significant impact on residential solar adoption rates in several states. Another factor likely affecting solar adoption rates is the market uncertainty when major reforms are under consideration and when utilities have reached state-established aggregate caps on net metering.

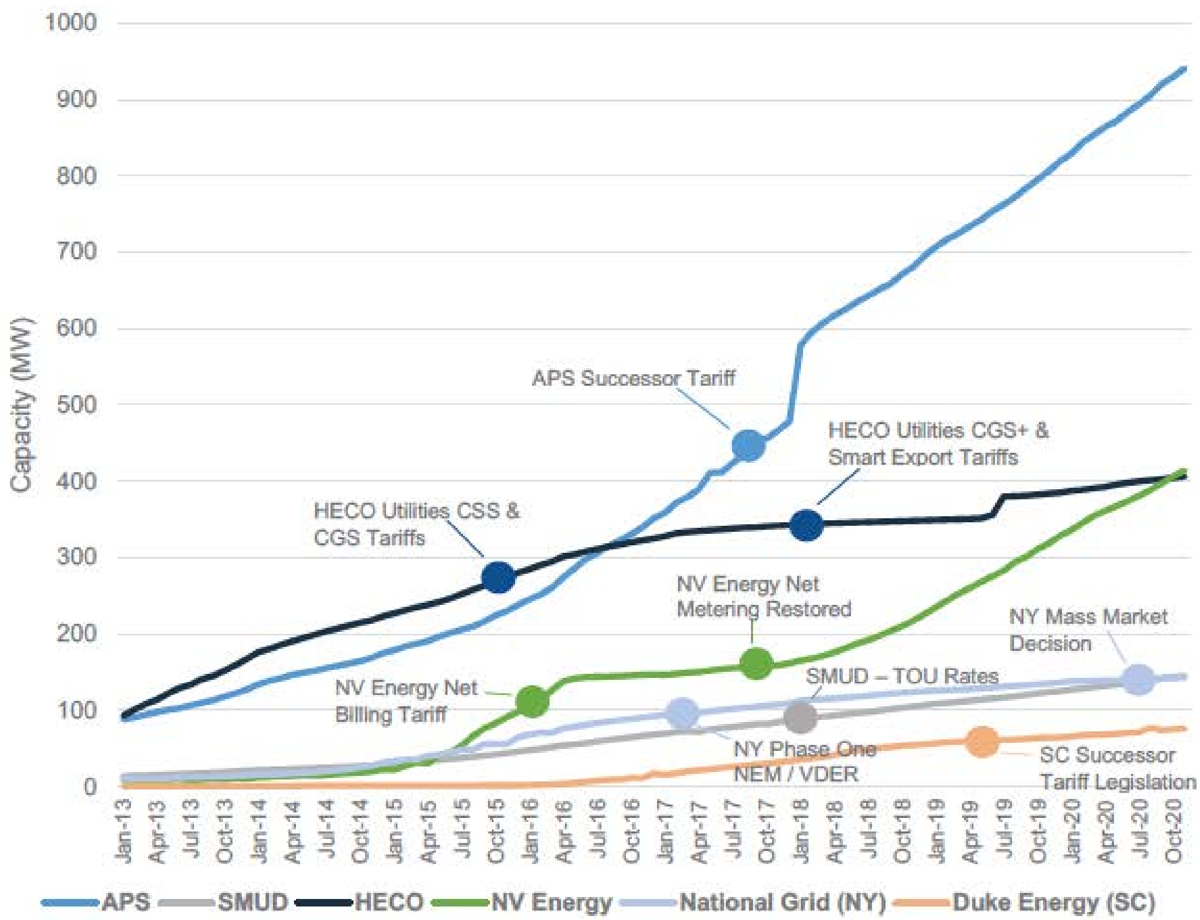
[1] Galen Barbose, Naim Darghouth, Eric O-Shaughnessy, and Sydney Forrester. Lawrence Berkeley National Laboratory. *Tracking the Sun Distributed Solar 2020 Data Update*. December 2020. https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf.

Table 3. Residential Solar Adoption Before and After Net Metering Reforms

Utility	NEM Reform Date	Avg. Monthly Capacity Additions Before NEM Reform (MW/Month for 12 Months Preceding Reform)	Avg. Monthly Capacity Additions After NEM Reform (MW/Month for 12 Months Following Reform)
Arizona Public Service	Sept. 2017	9.36	16.30
PacifiCorp (CA)	Mar. 2020	0.05	0.025*
HECO (CSS / CGS)	Oct. 2015	4.04	4.06
HECO (CGS+ / Smart Export)	Feb. 2018	0.97	0.43
NV Energy (Net Billing)	Jan. 2016	6.33	3.37
NV Energy (Net Metering)	Sept. 2017	0.96	3.36
National Grid (NY) – Phase One NEM / VDER	Mar. 2017	1.99	1.48
SMUD (TOU Rates)	Jan. 2018	1.40	1.54

* Average monthly capacity additions for Mar. – Nov. 2020

Figure 1. Residential Solar Net-Metered Capacity Over Time



Review of State Net Metering Reforms

Arizona (Arizona Public Service)

Net Metering Successor Tariff Development

In July 2013, Arizona Public Service (APS) filed an application to make changes to its net metering policy, asserting that solar net metering customers are shifting significant costs to other customers.[2] APS proposed two possible solutions: (1) maintaining the use of net metering and using new and existing retail rate schedules to recover the cost to serve solar customers through basic service charges, demand charges, or standby charges or (2) moving from net metering to a buy-all, sell-all compensation structure setting the purchase price for solar energy at either a market-based price or a price based on non-market, value-based concepts.[3]

In December 2013, the Arizona Corporation Commission (ACC) ruled on APS' petition, approving an interim Lost Fixed Cost Recovery adjustment of $0.70 per kW per month for new distributed generation (DG) customers to address cost shift issues.[4] The amount of the charge would be grandfathered for customers, with subsequent adjustments to the charge impacting new DG customers. The decision also stated that the Commission would open a generic docket on net metering issues and hold stakeholder workshop to inform future policy. In 2014, the Arizona Corporation Commission opened this generic docket on net metering issues and the value of distributed generation.[5]

In June 2016, APS filed a general rate case application including changes to its net metering tariff.[6] APS proposed a new net billing rider that would compensate all exported energy, measured on an instantaneous basis, at an avoided cost rate of 2.92 cents per kWh during the summer and 2.867 cents per kWh during the winter, while grandfathering existing rooftop solar customers for a period of 20 years from the date of interconnection. As part of APS' application the utility also proposed significant residential rate reforms. APS requested approval to move all residential customers, except certain low-use customers, to three-part rates including on-peak demand charges. All rooftop solar customers would be required to be on a three-part rate.

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[2] Application of Arizona Public Service Company for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248. July 12, 2013. https://docket.images.azcc.gov/0000146792.pdf?i=1614295521422.
[3] Application of Arizona Public Service Company for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248. July 12, 2013. https://docket.images.azcc.gov/0000146792.pdf?i=1614295521422.
[4] Decision No. 74202. Arizona Corporation Commission Docket No. E-01345A-13-0248. December 3, 2013. https://docket.images.azcc.gov/0000149849.pdf?i=1614295521422.
[5] Arizona Corporation Commission Docket No. E-00000J-14-0023. http://edocket.azcc.gov/search/docket-search/item-detail/18350.
[6] Arizona Public Service Company Rate Application. Arizona Corporation Commission Docket No. E-01345A-16-0036. June 1, 2016. https://docket.images.azcc.gov/0000170846.pdf?i=1614358276675.

In January 2017, the ACC issued a decision in its generic net metering docket, adopting the resource comparison proxy methodology for calculating the value of DG exports.[7] The order also determined that once the five-year avoided cost methodology is finalized, the ACC may use either this method or the resource comparison proxy method for setting the value of the DG export rate. Additionally, the decision ordered that rooftop solar customers would be treated as a separate rate class.

The ACC grandfathered existing DG customers for a period of 20 years from the date of interconnection, and determined that grandfathered DG customers that move will no longer maintain grandfathered status. However, customers moving to homes with grandfathered DG systems would be eligible for the grandfathered net metering rate. The grandfathering status does not apply to rate design changes, such as fixed charges.

In March 2017, parties filed a settlement agreement in APS' rate case on DG rate design issues.[8] The settlement allows DG customers to select from four different rate options, including an all-energy time-of-use rate (TOU-E) that does not include a demand charge. However, the TOU-E rate includes a grid access charge for DG customers. The settlement established the initial export credit rate using the resource comparison proxy method. The ACC issued an order on APS' rate case application in August 2017, approving the DG rate design provisions included in the settlement.[9]

Tariff Design

APS' current compensation tariff for distributed solar is the Resource Comparison Proxy (RCP) Export Rider.[10] The tariff allows customers to self-consume energy from on-site solar generation behind the meter. Power exported to the grid on an instantaneous basis is credited at the RCP rate. The ACC determines the RCP rate each year, and the rate may not be reduced by more than 10% each year. The current RCP rate effective through September 30, 2021 is $0.1045 per kWh, and beginning October 1, 2021 the rate will be $0.9405 per kWh.[11]

Net excess generation credits remaining at the end of the monthly billing period may be carried forward indefinitely, or the customer has the option of requesting a check for the outstanding credits at the end of the year. If the amount of the outstanding bill credits is greater than $25, the utility will automatically issue a check to the customer.

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[7] Decision No. 75859. Arizona Corporation Commission Docket No. E-00000J-14-0023. January 3, 2017. https://docket.images.azcc.gov/0000176114.pdf?i=1614371719161.

[8] Staff's Notice of Filing Settlement Term Sheet. Arizona Corporation Commission Docket No. E-01345A-16-0036. March 1, 2017. https://docket.images.azcc.gov/0000177680.pdf?i=1614358276675.

[9] Decision No. 76295. Arizona Corporation Commission Docket No. E-01345A-16-0036. August 18, 2017. https://docket.images.azcc.gov/0000182160.pdf?i=1614358276676.

[10] Resource Proxy Export Rate (RCP). Rate Schedules and Adjustors. Arizona Public Service. https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors.

[11] Resource Proxy Export Rate (RCP). Rate Schedules and Adjustors. Arizona Public Service. https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors.

Table 4. APS Resource Comparison Proxy Export Rider Summary

System Capacity Limit	System nameplate capacity may not exceed 150% of the customer's maximum one-hour peak demand over the prior 12 months.
Aggregate Capacity Limit	None
Netting Interval	Instantaneous
Export Credit Rates	Current export credit rate is $0.1045 per kWh. Customer credit rates are locked in for 10 years. The export credit rate is based on avoided cost using the resource comparison proxy method, but may not decrease by more than 10% per year.
Monthly Net Excess Generation	Carried forward indefinitely, unless outstanding bill credits at the end of the year exceed $25, in which case the utility will automatically issue a check. Customers have the option of requesting a check for outstanding credits at the end of the year.
Fees	Basic Service Charge: $0.427 per day TOU-E Rate: DG Grid Access Charge of $0.93 per kW-DC of generation R-2 Rate: On-peak demand charge of $8.40 per kW R-3 Rate: On-peak demand charge of $12.239 per kW (winter) and $17.438 (summer)
REC Ownership	Customer owns RECs
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Customers with rooftop solar plus battery storage have the option of participating in the pilot R-Tech tariff.
Utility or Aggregator System Control	N/A

Customers with on-site solar generation must take service on one of the utility's time-of-use rate plans, Saver Choice TOU-E, Saver Choice Plus R-2, or Saver Choice Max R-3.[12] Saver Choice TOU-E includes a basic service charge of $0.427 per day, as well as on-peak, off-peak, and super off-peak energy charges. The Saver Choice Plus R-2 and Saver Choice Max R-3 tariffs include a basic service charge of $0.427 per day, plus on-peak and off-peak energy charges and an on-peak demand charge. The Saver Choice TOU-E tariff does not include demand charges, but applies a monthly DG grid access charge of $0.93 per kW-DC of on-site generation.

[12] Rate Schedules and Adjustors. Arizona Public Service. https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors.

Table 5. Arizona Public Service DG Rate Options

Rate	Basic Service Charge	Time Periods	Energy Rates ($/kWh)	Demand Charges
TOU-E	$0.427/day	On-Peak: 3pm to 8pm, Mon. – Fri. year-round Off-Peak: All other hours Super Off-Peak: 10am to 3pm, Mon. – Fri. in winter Winter: Nov. – Apr. Summer: May – Oct.	On-Peak: $0.24314 (summer), $0.23068 (winter) Off-Peak: $0.10873 Super Off-Peak: $0.032	None, but includes $0.93/kW-DC generation grid access charge
R-2	$0.427/day	On-Peak: 3pm to 8pm, Mon. – Fri. year-round Off-Peak: All other hours Winter: Nov. – Apr. Summer: May – Oct.	On-Peak: $0.1316 (summer), $0.11017 (winter) Off-Peak: $0.07798	$8.40/kW during on-peak hours
R-3	$0.427/day	On-Peak: 3pm to 8pm, Mon. – Fri. year-round Off-Peak: All other hours Winter: Nov. – Apr. Summer: May – Oct.	On-Peak: $0.08683 (summer), $0.06376 (winter) Off-Peak: $0.0523	$17.438/kW during summer on-peak hours, $12.239/kW during winter on-peak hours
R-Tech	$0.493/day	On-Peak: 3pm to 8pm, Mon. – Fri. year-round Off-Peak: All other hours Winter: Nov. – Apr. Summer: May – Oct.	On-Peak: $0.0575 (summer), $0.0475 (winter) Off-Peak: $0.0475	On-Peak: $20.25/kW (summer), $14.25/kW (winter) Off-Peak: $6.50/kW for kW above first 5 kW

Low-Income Customer Provisions

APS' net billing tariff does not include any specific provisions applicable to low-income customers. APS offers two residential rate tariffs for customers using less than 600 kWh per month and less than 1,000 kWh per month, but these are not available to customers with on-site DG systems. APS offers a Solar Partner Program, in which the utility installs a solar system on a customer's rooftop, and the customer receives a $30 monthly bill credit for 20 years.[13] This program does not have any credit score requirements, so it may be more accessible to lower income households. This program is currently fully subscribed.

[13] Solar Partner Program. Arizona Public Service. https://www.aps.com/en/About/Sustainability-and-Innovation/Technology-and-Innovation/Solar-Partner-Program.

Energy Storage

Residential customers with two or more qualifying primary on-site technologies (rooftop solar, battery storage, and electric vehicles) or one qualifying primary on-site technology and two qualifying secondary on-site technologies (variable speed motor devices, grid-interactive water heaters, smart thermostats, and automated load controllers) may also participate in the pilot R-Tech tariff.[14] The R-Tech tariff includes a basic service charge of $0.493 per day, as well as on-peak and off-peak energy charges and both on-peak and off-peak demand charges. The off-peak demand charge is only applied to demand above the first 5 kW. The pilot tariff is limited to 10,000 participants.

Arizona Public Service also offers a Storage Rewards program in which the utility owns a battery system installed on a customer's premises, and the customer receives a $500 one-time bill credit.[15] The program is currently fully subscribed.

In November 2020, the ACC approved revisions to several of the state's energy rules, including an energy storage target of 5% of each utility's 2020 peak demand to be achieved by December 31, 2035.[16] Of this target, 40% is to be met with customer-owned or customer-sited distributed storage. The rules also direct utilities to establish energy storage incentive programs for the purchase or lease of distributed storage in exchange for participation in a demand response or similar program.

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[14] Saver Choice R-Tech. Rate Schedules and Adjustors. Arizona Public Service. https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors.
[15] Storage Rewards Program. Arizona Public Service. https://www.aps.com/en/About/Sustainability-and-Innovation/Technology-and-Innovation/Storage-Rewards.
[16] Order No. 77829. Arizona Corporation Commission Docket No. RU-00000A-18-0284. November 23, 2020. https://docket.images.azcc.gov/0000202570.pdf.

California (Los Angeles Department of Water & Power)

Net Metering Successor Tariff Development

Senate Bill 656 of 1995 required every electric utility in the state, including the Los Angeles Department of Water and Power (LADWP), to offer net metering on a first-come, first-served basis until the total installed capacity of customer-generators reaches 5% of the electric utility's aggregate customer peak demand.[17] Subsequent legislation requiring large investor-owned utilities to transition to a successor tariff upon meeting the 5% cap did not apply to LADWP, and LADWP continues to offer retail rate net metering.[18]

LADWP has not yet sought to move to a net billing or other type of net metering successor tariff, and is not affected by California's net metering 2.0 or successor proceedings. LADWP added a "power access" charge to its residential rates in 2016. This is a monthly charge based on a customer's maximum monthly kWh usage over the previous year.

Tariff Design

LADWP's Service Rider NEM uses retail rate net metering, with excess generation credited at retail rates and carried forward indefinitely.[19] Excess generation credits cannot be used to offset taxes, minimum charges, and other non-energy charges. The standard residential rate (R-1 Rate A) uses tiered rates during the high season (June to September), with different rates being charged for different levels, or "tiers," of usage. The tiers differ depending on customer location. In Zone 1, Tier 1 makes up the first 350 kWh, Tier 2 is the next 700 kWh, and Tier 3 makes up any usage beyond 1,050 kWh, while in Zone 2, Tier 1 makes up the first 500 kWh, Tier 2 the next 1,000 kWh, and Tier 3 any usage beyond 1,500 kWh. The tiered rates do not apply in the low season (October to May); during that period flat volumetric rates apply, with the rate being equal to the rate charged for the first 350 (or 500) kWh during the high season. A residential time-of-use rate (R-1 Rate B) is also available, and customers on this rate are eligible for net metering. The time-of-use rate does not differentiate based on location, but does have different rates based on season.

Both the standard and time-of-use rates include a power access charge. This charge is based on the customer's highest monthly kWh usage over the previous year, with the same usage tiers as described for the energy rates. The monthly power access charge for Tier 1 is $2.30, for Tier 2 is $7.90, and for Tier 3 is $22.70. Net metering credits can be used to offset the power access charge, and, because solar generation reduces net consumption, can change which month

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[17] S.B. 656, (1995 Reg. Session). http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html.

[18] A.B. 327 (2013 Reg. Session). http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.html.

[19] Service Rider NEM. Los Angeles Department of Water & Power. https://www.ladwp.com/ladwp/faces/wcnav_externalId/a-fr-elecrate-schel?_adf.ctrl-state=1cij4bclum_29&_afrLoop=200391020557265.

includes the customer's maximum consumption and possibly reduce the power access charge by moving the customer to a lower tier.

Table 6. LADWP Service Rider NEM Summary

System Capacity Limit	1 MW
Aggregate Capacity Limit	None
Netting Interval	Monthly
Export Credit Rates	Retail rate
Net Excess Generation	Net excess generation carried over indefinitely, but cannot be used to pay taxes or minimum charges.
Fees	Minimum charge of $10.00. Interconnection fees apply for systems over 20 kW or that require system upgrades.
REC Ownership	Customer owns RECs
Low- and Moderate Income Customer Provisions	Solar Rooftops Program
Energy Storage Provisions	Allowed
Utility or Aggregator System Control	N/A

LADWP does not charge additional interconnection fees for the interconnection of solar photovoltaic (PV) systems of 20 kW or less and which do not require upgrades to install. The fee for systems of 20 to 30 kW is $3,000, for systems 30 to 100 kW is $3,500, and 100 kW to 1 MW is $4,500. LADWP announced in summer 2020 that it was proposing revised fee schedules for interconnection, with a fixed-cost recovery charge of between $75 and $145.[20] The fee change does not appear to apply fees to projects that would not pay fees under the existing rules; instead, it changes the fee amounts for projects that already need to pay fees. For projects in the approval process at the time the new fees are implemented, the owner will be able to select the lower fee amount between the old and new fee structures.

LADWP also has a Solar Feed-In Tariff program.[21] This program is available for customers with 30 kW or more of solar capacity and offers a fixed payment per kWh of electricity generated, but

[20] LADWP Solar Interconnection Fees and FAQs. Low Angeles Department of Water & Power. https://www.ladwpnews.com/ladwp-solar-interconnection-fees-information-and-faqs-summer-2020/.
[21] Feed-In Tariff. Los Angeles Department of Water & Power. https://www.ladwp.com/ladwp/faces/wcnav_externalId/r-gg-rs-fit?_adf.ctrl-state=noo5oy67n_4&_afrLoop=1135695325206864

does not allow participation in net metering. The feed-in tariff payment for solar PV projects in the main LADWP service territory is $0.145 per kWh for projects 30-500 kW in capacity, $0.140 per kWh for 500 kW-3 MW projects, and $0.135 per kWh for larger projects. In the Owens Valley service territory the feed-in tariff is only available for projects from 30-500 kW, and the payment is $0.115 per kWh. The contract term for the feed-in tariff is 20 years. The Feed-In Tariff program has a total remaining capacity of 19.6 MW, with 82.5 MW currently in service.

Low- and Moderate-Income Customer Provisions

LADWP's Solar Rooftops Program leases rooftop space for deployment of utility-owned solar panels, and is intended to expand access to solar for customers who would not be able to afford to own panels directly.

California's Self-Generation Incentive Program (SGIP) has a dedicated equity budget consisting of 25% of energy storage program funds (or 20% of total funds).[22] The SGIP is not technically offered to LADWP customers, but it is available to customers of SoCalGas, a gas utility that covers all of LADWP's service territory, so the program is accessible to LADWP customers with SoCalGas accounts. The equity budget is available for projects serving customers who meet eligibility thresholds: for single-family households, they must have income of less than 80% of the Area Median Income and live in a house with an affordable housing designation subject to a resale restriction or an equity sharing agreement. For multifamily housing and nonprofit customers, the eligibility requirement is that they be located in an area where at least 80% of households have incomes less than 60% of the Area Median Income. An additional carve-out applies for equity budget customers with resiliency needs, such as having experienced power shutoffs, reliance on electric pump wells for water, and medical conditions.

Energy Storage

LADWP allows the interconnection of battery energy storage systems, either paired with solar or standalone. Paired solar and storage systems are eligible for net metering, although systems including storage are not eligible for a fast-track interconnection process that is otherwise available for solar systems of less than 10 kW.[23] LADWP does not currently offer additional incentives for energy storage. The utility may update its feed-in tariff program to include energy storage in the future.[24]

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[22] Self-Generation Incentive Program. California Public Utilities Commission. https://www.cpuc.ca.gov/sgip/.
[23] Installation Information. Los Angeles Department of Water & Power. https://www.ladwp.com/ladwp/faces/ladwp/residential/r-gogreen/r-gg-ressolar/r-gg-sp-solarinfo?_adf.ctrl-state=jipu7e66k_4&_afrLoop=1292374146549525
[24] LADWP Solar Interconnection Fees and FAQs. Los Angeles Department of Water & Power. https://www.ladwpnews.com/ladwp-solar-interconnection-fees-information-and-faqs-summer-2020/.

California (PacifiCorp)

Net Metering Successor Tariff Development

Senate Bill 656 of 1995 required every electric utility in the state, including PacifiCorp, to offer net metering on a first-come, first-served basis until the total installed capacity of customer generators reaches 5% of the electric utility's aggregate customer peak demand.[25] Subsequent legislation requiring large utilities to transition to a successor tariff upon meeting the 5% cap did not apply to PacifiCorp, which serves fewer than 100,000 customers. PacifiCorp continued offering net metering after exceeding the 5% cap.[26]

In April 2019, PacifiCorp filed an application for a net billing tariff to replace net metering on or before June 30, 2020.[27] Under the proposed program, customers would be able to self-consume their own generation, effectively being credited at retail rate. Any exported energy would be credited at a separate rate that includes: (1) avoided energy costs, (2) avoided line losses, (3) integration costs, (4) avoided greenhouse gas emission compliance costs, and (5) avoided renewables portfolio standard compliance costs. The credit rates would also be differentiated by time of export with on-peak and off-peak credit pricing.

The California Public Utilities Commission approved the net billing tariff in January 2020.[28] PacifiCorp is to file an annual export credit update advice letter with a Tier 1 designation on November 1 of each year. In the event that PacifiCorp receives approval for different peak and off-peak hours in its next general rate case, it is to file a Tier 2 advice letter to adjust the time periods for its net billing tariff. The Commission also directed PacifiCorp to continue accepting net metering applications until March 1, 2020, with eligible applicants having until March 1, 2023 to successfully interconnect their systems. All legacy net metering customers may continue under the net metering tariff until March 1, 2040.

Tariff Design

PacifiCorp's NB-136 Tariff allows customers to self-consume the electricity produced by their system. A customer will be billed for all imported energy at the applicable standard tariff rate, and all exported energy will be credited at a value dependent upon the time of day and applied to the customer's bill to offset all charges except the basic facilities charge:

- On-Peak Credit Rate (Monday through Friday, 4:00 PM - 10:00 PM): $0.04865/kWh
- Off-Peak Credit Rate (All other times): $0.03699/kWh

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[25] S.B. 656 (1995 Reg. Session). http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html.

[26] A.B. 327 (2013 Reg. Session). http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.html.

[27] California Public Utilities Commission Docket No. A-19-04-013. https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1904013.

[28] Decision No. 20-01-007. California Public Utilities Commission Docket No. A-19-04-013. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M324/K554/324554523.pdf.

Any exported energy credits in excess of the charges eligible to be offset on a customer's monthly bill will be rolled forward to the following month, and all unused exported energy credits will expire at the end of the March billing period with the exception of customers taking service under an agricultural pumping rate schedule. Unused exported energy credits for these customers will expire at the end of the October billing period.

Table 7. PacifiCorp Net Billing Service Summary

System Capacity Limit	1 MW
Aggregate Capacity Limit	Not specified
Netting Interval	Instantaneous
Export Credit Rates	All exports receive an export credit that varies by time of day. On-Peak Exports: $0.04865 per kWh Off-Peak Exports: $0.03699 per kWh
Monthly Net Excess Generation	Carried forward, but expires at the end of the annual period.
Fees	Basic Monthly Charge: $7.53 One-time $75 application fee
REC Ownership	Customers may opt to transfer RECs to the utility to receive the Renewable Attribute Rider: $0.002/kWh
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Allowed. PacifiCorp will collect data on the installation of energy storage systems by net billing customers and report annually to the Commission, along with a recommendation of whether a cap should be placed on energy storage installations.
Utility or Aggregator System Control	N/A

California (Sacramento Municipal Utility District)

Net Metering Successor Tariff Development

Senate Bill 656 of 1995 required every electric utility in the state, including Sacramento Municipal Utility District (SMUD), to offer net metering on a first-come, first-served basis until the total installed capacity of customer generators reaches 5% of the electric utility's aggregate customer peak demand.[29] By the nature of SMUD being a municipal utility, it is outside the jurisdiction of the California Public Utilities Commission, and was not a party to the Commission's subsequent net metering proceedings. SMUD continues to offer traditional net metering with monthly net excess generation credited to participants at the retail rate, but the utility is in the process of developing a net energy metering (NEM) 2.0 successor tariff.

On January 1, 2018, it became mandatory for new net metering customers to enroll in SMUD's time-of-use rate that includes a peak period of 5:00 to 8:00 PM.[30] The current time-of-use rates range from $0.1061 per kWh to $0.3105, depending on season and time of day. Net metering customers with generating facilities approved for installation before January 1, 2018 who were enrolled in SMUD's now-closed time-of-use rate including a 4:00 to 7:00 PM peak period may remain on this rate until December 31, 2022. New net metering customers enrolling on or after January 1, 2018 will also be subject to SMUD's NEM 2.0 successor tariff when it is implemented.[31]

SMUD leadership proposed a NEM 2.0 successor tariff in 2019.[32] The revised tariff would continue to compensate excess generation at the retail rate, but also include a monthly Grid Access Charge. The proposed Grid Access Charge varies based on rate class and service voltage, and would increase over time. The proposed charge for residential customers was $8 per installed kW of net metering capacity per month for 2020 and 2021, ramping up to $11 per installed kW per month in 2025. SMUD later withdrew its proposal after receiving significant public backlash.[33]

Later in 2019, SMUD launched a stakeholder process to develop a new NEM 2.0 tariff. A Technical Working Group met several times in 2019 and 2020 and agreed on 24 valuation criteria to be used in a valuation analysis:

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[29] S.B. 656, (1995 Reg. Session). http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html.

[30] Residential Time-of-Day Service. Sacramento Municipal Utility District. Effective January 1, 2021. https://www.smud.org/-/media/Documents/Electric-Rates/Residential-and-Business-Rate-information/PDFs/1-R-TOD.ashx.

[31] Successor Net Energy Metering. Sacramento Municipal Utility District. Effective June 25, 2019. https://www.smud.org/-/media/Documents/Electric-Rates/Residential-and-Business-Rate-information/PDFs/1-NEM2.ashx.

[32] *2019 Chief Executive Officer and General Manager's Report and Recommendation on Rates and Services*. March 21, 2019. https://www.smud.org/-/media/Documents/Rate-Information/2019-Rate-Action/GM-Report-Volume-1.ashx.

[33] *Addendum to the Chief Executive Officer and General Manager's Report and Recommendation on Rates and Services*. April 22, 2019. https://www.smud.org/-/media/Documents/Rate-Information/2019-Rate-Action/GM-Report-Addendum-2.ashx.

1. Avoided energy, including greenhouse gas and renewable portfolio standard requirements
2. Integration costs
3. Higher marginal cost of emissions (intermittency)
4. Resource adequacy
5. Resource flexibility (increased need for flexibility)
6. Fuel price risk reduction
7. Increases in energy price volatility
8. Sunk cost of emission reduction credits
9. Decreased thermal operations
10. Increased standby costs
11. Criteria emissions reductions
12. Carbon reductions beyond SMUD compliance requirements
13. Reduced land and water usage
14. Reduced energy burden for low-income customers
15. Customer ability to meet critical needs
16. Restoring service or preventing outages in an emergency
17. Engaging customers through net metering, changing their relationship with energy
18. Jobs and local economic growth resulting from rooftop solar
19. Transmission capacity
20. Transmission line losses
21. Distribution capacity
22. Distribution line losses
23. Grid modernization
24. Voltage and power quality

The Value of Solar and Solar + Storage Study (VOS Study) was released in September 2020.[34] Six of the values identified by the Technical Working Group (higher marginal cost of emissions, sunk cost of emission reduction credits, reduced energy burden for low-income customers, engaging customers through net metering, jobs and local economic growth resulting from rooftop solar, and grid modernization) were deemed qualitative and were quantified as part of the analysis. These values were instead discussed within the narrative of the report.

The quantitative analysis found that the value of customer-owned solar and solar-plus-storage systems is outweighed by the compensation they receive by $0.05 to $0.09 per kWh, resulting in an annual bill increase of $26 to $45 for the average residential customer. SMUD plans to conduct broader outreach to its customers and community stakeholders before presenting new NEM rate options to the SMUD Board of Directors in mid-2021. If approved, the new NEM policies and rates would be effective in 2022.

[34] Energy+Environmental Economics. *SMUD Value of Solar and Solar + Storage Study*. September 2020. https://www.smud.org/-/media/Rate-Information/NEM/VOSstudy.ashx.

Tariff Design

SMUD's rate schedule NEM1 uses retail rate net metering, with excess generation credited at retail rates and carried over monthly. Customers enrolling on or after January 1, 2018 must take service on SMUD's time-of-use rate that includes a 5:00 to 8:00 PM peak period. All net metering customers have a 12-month settlement period, which begins on the day the system is approved by SMUD for grid connection. The customer can choose between two options for any remaining net surplus generation at the end of their 12-month settlement period. The net surplus generation can be rolled over into the next 12-month settlement period, or the customer can receive a payment from SMUD at a rate determined annually.

The RECs associated with any purchased net surplus energy convey to the utility. Customers cannot offset non-bypassable fees, including the system infrastructure fixed charge, maximum demand charge, site infrastructure charge, summer peak demand charge, program fees, surcharges, and taxes.

Table 8. SMUD Net Metering (NEM1) Summary

System Capacity Limit	3 MW
Aggregate Capacity Limit	5% of peak load; SMUD continues to offer net metering despite reaching this threshold.
Netting Interval	Monthly
Export Credit Rates	Retail rate (TOU Rates are mandatory for net metering customers enrolling on or after January 1, 2018)
Monthly Net Excess Generation	Customer choice between indefinite rollover or utility purchase at special rate at the end of the year ($0.0562 per kWh for 2021)
Fees	System Infrastructure Fixed Charge: $22.25 Customers are responsible for non-bypassable fees, including the system infrastructure fixed charge, program fees, surcharges, and taxes.
REC Ownership	Remain with the customer, unless the customer opts for utility purchase of annual net excess generation
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Not specified
Utility or Aggregator System Control	N/A

Hawaii (HECO Utilities)

Net Metering Successor Tariff Development

In response to the rapid growth of distributed energy resources in Hawaii, the Hawaii Public Utilities Commission observed that "the distributed solar PV industry in Hawaii will, out of necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges - to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system, and hopefully becomes a key contributor to Hawaii's grid modernization...".[35]

In furtherance of these goals, the Commission capped net metering and established two new interim distributed energy resource (DER) options in 2015, the Customer Self Supply (CSS) tariff and the Customer Grid Supply (CGS) tariff.[36] The CSS Tariff was designed to allow customers to self-consume the power generated by their systems. Systems must be designed such that all of the output is consumed by the customer and no power is exported to the grid. The CGS tariff was initially capped at 25 MW for HECO and 5 MW each for MECO and HELCO service territories.

The Hawaii Public Utilities Commission adopted new DER tariffs in 2017, a Smart Export tariff, and a Customer Grid Supply Plus (CGS+) tariff.[37] The Smart Export tariff was designed to compensate customers with renewable energy systems paired with energy storage for exports made during non-daytime hours. The CGS+ tariff is intended for systems not paired with storage, which will be equipped with communication and control equipment that allows the utility to curtail the system when the utility is at risk of violating an operation constraint on the system.

Tariff Designs

The CSS Tariff is designed to allow customers to self-consume the power generated by their systems. Systems must be designed such that all of the output is consumed by the customer and no power is exported to the grid. In order to qualify as a Self-Supply System under the Company's Customer Self-Supply tariff, the Generating Facility must utilize one or more of the following options:

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[35] Order No. 32053, p. 49 – 50. Hawaii Public Utilities Commission Docket No. 2011-0206. https://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32053.pdf.
[36] Order No. 33258. Hawaii Public Utilities Commission Docket No. 2014-0192. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464.
[37] Order No. 34924. Hawaii Public Utilities Commission Docket No. 2014-0192. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A17J23B15234B02181.

Option 1 ("Reverse Power Protection"): To ensure power is never exported across the point of interconnection, a reverse power relay may be provided. The default setting for this protective function must be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.

Option 2 ("Minimum Power Protection"): To ensure at least a minimum amount of power is imported by the customer at all times (and, therefore, that power is not exported, other than for the short time periods noted), an under-power protective function may be provided. The default setting for this minimum power protection must be 5% (import) of the generating facility's total gross rating, with a maximum 2.0 second time delay.

Table 9. HECO Customer Self Supply (CSS) Tariff Summary

System Capacity Limit	100 kW
Aggregate Capacity Limit	None
Netting Interval	N/A
Export Credit Rates	Energy exports are not allowed.
Monthly Net Excess Generation	N/A
Fees	Residential Customer Charge: $11.50 Residential Minimum Bill: $25; Commercial Minimum Bill: $50
REC Ownership	Not specified
Low- and Moderate- Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must receive an interconnection review by the utility
Utility or Aggregator System Control	N/A

The CGS tariff uses a net billing compensation structure. Customers with systems up to 100 kW may self-consume the electricity produced by their system, and any energy exported by the system to the grid will be credited at an island-specific "export credit rate."[38] Energy credits may only reduce the electric bill of a customer to an amount equal to the minimum charge for the applicable rate schedule. Any energy credits not applied in each billing period are forfeited. The CGS tariff was initially capped at 25 MW for HECO and 5 MW each for MECO and HELCO service territories. Capacity was later added for each of the islands from net metering

[38] Rule No. 23 (Customer Grid Supply Tariff). Hawaiian Electric Company. Effective June 13, 2016. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/23.pdf.

applications that were cancelled or withdrawn. The aggregate capacity limits have now been reached for each island.

Table 10. HECO Customer Grid Supply (CGS) Tariff Summary

System Capacity Limit	100 kW
Aggregate Capacity Limit	Oahu: 51.31 MW Maui County: 14.12 MW Hawaii Island: 9.91 MW
Netting Interval	Instantaneous
Export Credit Rates	\$0.1514/kWh to \$0.2788/kWh, depending on the island.
Monthly Net Excess Generation	Excess energy credits not applied in each billing period are terminated.
Fees	Residential Customer Charge: \$11.50 Residential Minimum Bill: \$25; Commercial Minimum Bill: \$50
REC Ownership	Not specified
Low- and Moderate- Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must receive an interconnection review by the utility
Utility or Aggregator System Control	N/A

The Customer Grid Supply Plus (CGS+) tariff was designed to function like the CGS tariff, but participating systems must incorporate technology that allows the utility to measure, monitor, and, if necessary, control the system. When grid conditions dictate, CGS+ systems may be curtailed as a single block. Curtailment of these systems will only occur after controllable renewable resources with lower curtailment priority have been fully curtailed and the utility is at risk of violating a system operational constraint that is necessary to maintain reliable service.[39] System control may be managed by a third-party or through a double-meter installation by the utility.[40]

Customers will receive a monthly bill credit for energy exported to the grid. Energy credits may only reduce the electric bill to an amount equal to the minimum charge for the applicable rate schedule. Unlike the original CGS program, which incorporates a fixed rate for export credits based on figures approved at the time of its establishment, the CGS+ program uses updated

39 Rule No 24 (Customer Grid Supply Plus Tariff). Hawaiian Electric Company. Effective February 20, 2018. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/24.pdf.
40 Customer Grid Supply Plus. Hawaiian Electric Company. https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/customer-grid-supply-plus

figures under this methodology to provide a more accurate value of the energy to the HECO companies. The export credit is fixed for a period of five years (until October 20, 2022).[41] After five years, the Commission may modify the credit at its discretion.

Table 11. Customer Grid Supply Plus (CGS+) Tariff Summary

System Capacity Limit	100 kW
Aggregate Capacity Limit	Oahu: 35 MW Maui County: 7 MW Hawaii Island: 12 MW
Netting Interval	Instantaneous
Export Credit Rates	Oahu: $0.1008/kWh, Maui: $0.1217/kWh, Lanai: $0.2080/kWh, Molokai: $0.1677/kWh, Hawaii: $0.1055/kWh
Monthly Net Excess Generation	Excess energy credits are carried over monthly and reconciled at the end of a 12-month period at the export rate.
Fees	Residential Customer Charge: $11.50 Residential Minimum Bill: $25; Commercial Minimum Bill: $50
REC Ownership	Not specified
Low- and Moderate- Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must receive an interconnection review by the utility.
Utility or Aggregator System Control	The utility may monitor the system and, if necessary, curtail the system in the event of a grid emergency.

Customers must have renewable energy systems paired with energy storage to utilize the Smart Export tariff.[42] Customers do not receive compensation for energy exported to the grid from 9:00 AM to 4:00 PM. Instead, customers are to use any excess energy to charge their energy storage systems. Any energy exported to the grid from 4:00 PM to 9:00 AM will receive a bill credit using an island-specific credit rate, which is fixed until October 20, 2022.[43] Any energy export credits remaining after a 12-month period will expire with no compensation to the customer. Customers participating in the smart export program must use an advanced inverter and advanced metering technology to manage the battery's charging.[44]

[41] Customer Grid-Supply Plus. Hawaiian Electric Company. https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/customer-grid-supply-plus.
[42] Rule No. 25 (Smart Export Program). Hawaiian Electric Company. Effective February 20, 2018. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/25.pdf.
[43] Smart Export Fact Sheet. Hawaiian Electric Company. https://www.hawaiianelectric.com/Documents/products_and_services/customer_renewable_programs/HE_smart_export_factsheet.pdf.
[44] Smart Export. Hawaiian Electric Company. https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/smart-export.

Table 12. HECO Smart Export Tariff Summary

System Capacity Limit	100 kW
Aggregate Capacity Limit	Oahu: 25 MW Maui County: 5 MW Hawaii Island: 10 MW
Netting Interval	Instantaneous
Export Credit Rates	Oahu: $0.1497/kWh, Maui: $0.1441/kWh, Lanai: $0.2079/kWh, Molokai: $0.1664/kWh, Hawaii: $0.1100/kWh No credit is provided for exports from 9:00 AM to 4:00 PM.
Monthly Net Excess Generation	Excess energy credits not applied in each billing period are terminated.
Fees	Residential Customer Charge: $11.50 Residential Minimum Bill: $25; Commercial Minimum Bill: $50
REC Ownership	Not specified
Low- and Moderate- Income Customer Provisions	N/A
Energy Storage Provisions	Systems must be paired with storage and configured to charge from solar only between 9:00 AM and 4:00 PM and export energy between 4:00 PM and 9:00 AM.
Utility or Aggregator System Control	N/A

Nevada (NV Energy)

Net Metering Successor Tariff Development

Nevada originally adopted retail rate net metering in 1997. In 2015, the Public Utilities Commission of Nevada (PUCN) issued an order moving the state to a net billing system for compensation of distributed generation (DG).[45] This order followed legislation enacted earlier in 2015, which directed utilities to file and the Commission to approve new net metering tariffs after the cumulative installed capacity of net metering systems of 25 kW or less had reached 235 MW. The 2015 changes to net metering policy were to some degree informed by a study performed by Energy and Environmental Economics (E3) in 2014, on behalf of the Commission.[46]

The net billing system included movement of DG customers to a separate rate class with an increased basic service charge, as well as hourly exports credited at the avoided cost rate. This change did not include any grandfathering provision exempting existing DG customers from the rate changes. Grandfathering provisions have since become standard in successor tariff proposals in other states. The 2015 rate change resulted in substantial controversy and a reported decline in solar industry activity in the state.[47]

In 2017, the state legislature passed A.B. 405, requiring a return to traditional net metering with monthly netting, and forbidding placement of DG customers into a separate rate class.[48] A.B. 405 introduced a gradual step-down for the value of credits for excess generation; it began at 95% of retail rate in 2017 and has gradually declined to 75%, but it will not decline any further under current law. This rate only applies to monthly net excess generation, so generation up to the customer's monthly consumption is effectively credited at the full retail rate.

Tariff Design

Nevada currently requires utilities to compensate net metering customers with 25 kW of capacity or less at 75% of the retail rate for monthly net excess generation. Under NV Energy's net metering tariff, excess generation credits can be carried over indefinitely and are only forfeited if the customer ends service or transfers their account to a different location. Generation credits cannot be used to offset basic service charges, additional meter charges,

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[45] Order Granting In Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405. Public Utilities Commission of Nevada Docket No. 17-07026. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-7/23611.pdf.

[46] Energy+Environmental Economics. *Nevada Net Energy Metering Impacts Evaluation*. July 2014. https://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[47] Lincoln Davies & Sanya Carley. *Emerging Shadows in National Solar Policy? Nevada's Net Metering Transition in Context*. SJ Quinney College of Law. University of Utah. February 2017. https://core.ac.uk/download/pdf/217370203.pdf.

[48] Nevada Assembly Bill 405, (2017 Reg. Session). https://www.leg.state.nv.us/Session/79th2017/Bills/AB/AB405_EN.pdf.

local government fees, or gas charges.[49] For customers with over 25 kW and less than 1 MW of net metering capacity, NV Energy allows full retail rate net metering and provides a kWh credit for net excess generation that may be carried forward indefinitely.

The table below uses NV Energy's standard volumetric rate for residential service. NV Energy also allows residential customers to choose a time-of-use rate and/or an electric vehicle rate, and customers using those rates are eligible for net metering.

Table 13. NV Energy Net Metering Rider-405 and Net Metering Rider-B Summary

System Capacity Limit	NMR-405: 25 kW NMR-B: >25 kW to 1,000 kW
Aggregate Capacity Limit	None
Netting Interval	Monthly
Export Credit Rates	Retail rate
Monthly Net Excess Generation	NMR-405: Credited at 75% of retail rate (currently $0.07565 per kWh). Credits may carry forward indefinitely. NMR-B: kWh credits carry over indefinitely.
Fees	Residential Basic Service Charge: $15.25 (Northern Nevada), $12.50 (Southern Nevada) General Service Basic Service Charge: $32.00 (Northern Nevada), $25.50 (Southern Nevada)
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, and additional incentives offered
Utility or Aggregator System Control	N/A

Low-Income Customer Provisions

Although no low-income solar programs currently exist for NV Energy customers, NV Energy is developing an Expanded Solar Access Program to meet the requirements of A.B. 465 of 2019.[50] This program will allow customers meeting income, disadvantaged business, or physical

[49] Net Metering. NV Energy. https://www.nvenergy.com/account-services/energy-pricing-plans/net-metering.
[50] Application of Nevada Power Company and Sierra Pacific Power Company for Approval of their Joint Expanded Solar Access Program Implementation Plan. Public Utilities Commission of Nevada Docket No. 20-12-003. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2020_THRU_PRESENT/2020-12/6203.pdf.

constraint qualifications (income must not be more than 80% of area median income for residential customers) to pay a special electric rate in order to have their electric consumption be derived from a mix of utility-scale and community-based solar resources.

The special rate will consist of 70% of the customers' base energy rates and 30% of the rate needed to support new utility-scale and community-based solar resources; the special rate only replaces the energy portion of a customer's electric rates. For 2022 (the first year the program is expected to be available), the projected energy rates for both residential and non-residential customers under the Expanded Solar Access Program would range from $0.05015 to $0.05351 per kWh; these rates exceed the base tariff energy rates by $0.00251 to $0.00404 per kWh. NV Energy's application states that these rates will be reduced for lower-income customers, but has not yet proposed the method or amount of this reduction.

Energy Storage

NV Energy allows paired solar plus storage systems to net meter. NV Energy also offers Critical Peak Pricing and Daily Demand Pricing rate options, which may be advantageous for customers with energy storage.[51]

The utility also offers a residential storage incentive program. [52]The incentive is a one-time payment, and is doubled for customers on time-of-use (TOU) rates. The incentive is currently $0.095 per Watt-hour for non-TOU customers, and $0.19 per Watt-hour for TOU customers; when a total of $2 million in incentive payments have been made, the incentive payments will step down to $0.08 and $0.16 per Watt-hour. Application for the incentive requires a review fee of $130 for systems of less than 10 kW, $200 for systems of 10-25 kW, and $500 for systems above 25 kW.

NV Energy also offers a commercial storage incentive program.[53] The incentive payments for 4-100 kW commercial storage systems paired with solar is $0.32 per Watt-hour if the system is eligible for the Federal Investment Tax Credit, and $0.42 per Watt-hour if it is not.

[51] Critical Peak Price. NV Energy. https://www.nvenergy.com/account-services/energy-pricing-plans/critical-peak-price; Daily Demand Pricing. NV Energy. https://www.nvenergy.com/account-services/energy-pricing-plans/daily-demand-pricing.
[52] Residential Energy Storage Incentives. NV Energy. https://www.nvenergy.com/cleanenergy/energy-storage/residential-storage.
[53] Commercial Energy Storage Incentives. NV Energy. https://www.nvenergy.com/cleanenergy/energy-storage/commercial-storage.

New York (National Grid)

Net Metering Successor Tariff Development

New York's Department of Public Service (DPS), under direction from Governor Cuomo, began a process called Reforming the Energy Vision (REV) in 2014. REV aims to reform energy regulation in New York in order to enable achievement of state clean energy policy objectives and give customers new opportunities for energy savings, local power generation, and enhanced reliability.[54] The Public Service Commission (PSC), New York's utility regulatory commission and part of DPS, initiated its REV proceeding in 2015.

The portion of REV dedicated to distributed generation (DG) compensation is called Value of Distributed Energy Resources (VDER) and has been ongoing since 2015, with major decisions changing rate structures issued in 2017 and 2020. The 2017 order created a separate compensation system, called the Value Stack, for PV systems over 750 kW and community DG projects. Other DG projects remained able to use traditional net metering, although customers can elect to use the Value Stack.

Staff of the Public Service Commission released a white paper on options for a "mass market" successor tariff in December 2019, with the term mass market referring to customers of New York investor-owned utilities whose electric service rates use only volumetric, rather than demand-based components, who have DG capacity installed behind the meter, and who do not use that capacity to offset consumption at another site.[55] The paper recommended adoption of a capacity-based charge to recoup costs for public benefit programs, and to extend the availability of net metering. The white paper noted that this rate change would not cover the full cost shift in favor of DG customers, but recommended it in the interest of REV's focus on gradualism and avoiding adverse market reactions.

An order issued in July 2020 largely adopted the recommendations made in the 2019 white paper, although with an extended time frame (the white paper recommended implementing the new rate beginning in 2021, while the order begins implementation in 2022). The order approved a new DG capacity-based charge ("Customer Benefit Contribution") estimated at \$0.69 to \$1.09 per kW of installed DG capacity, depending on the utility. The tariff otherwise retains retail rate net metering for mass market customers.

Tariff Design

New York has two different compensation systems for DG facilities: Phase One Net Energy Metering and the Value Stack. Phase One Net Metering is available for "mass market"

[54] About the Initiative. DPS – Reforming the Energy Vision. https://www3.dps.ny.gov/w/pscweb.nsf/all/cc4f2efa3a23551585257dea007dcfe2.
[55] Staff Whitepaper on Rate Design for Mass Market Net Metering Successor Tariff. December 2019. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8a5f3592472a270c852580880517bdd/$FILE/NEM%20REplacement%20Whitepaper.pdf.

customers with systems of less than 750 kW-AC capacity only. Customers with larger systems, remote net metering customers, and community DG customers must use the Value Stack tariff. Phase One Net Metering is functionally identical to retail rate net metering, although with a 20-year contract term and net excess generation credits carried over indefinitely, rather than paid out annually.

Table 14. National Grid Phase One Net Metering Summary

System Capacity Limit	750 kW
Aggregate Capacity Limit	None
Netting Interval	Monthly
Export Credit Rates	Retail rate
Monthly Net Excess Generation	Carries over indefinitely
Fees	Basic Service Charge: $17.00 Monthly Customer Benefit Contribution (CBC) for systems installed beginning in 2022 ($1.15 per kW installed capacity for National Grid)
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	Solar for All Program Affordable Solar NY-SUN Program NYSERDA financing programs
Energy Storage Provisions	Mass market DG plus storage projects are eligible for Phase One Net Metering.
Utility or Aggregator System Control	N/A

The Value Stack is a value of DER-based tariff that attempts to credit customer-generators more precisely for the energy they provide to the grid. The tariff includes five value components: (1) Energy Value (based on location-based marginal price on the New York Independent System Operator system), (2) Capacity Value, (3) Environmental Value, (4) Demand Reduction Value, and (5) Locational System Relief Value.[56] The New York State Energy Research and Development Authority (NYSERDA) has made a Value Stack calculator available to help estimate value stack compensation.[57]

[56] The Value Stack. New York State Energy Research and Development Authority. https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources
[57] Solar Value Stack Calculator. New York State Energy Research and Development Authority. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator

In July 2020, New York regulators adopted a Customer Benefit Contribution (CBC), a DG capacity-based charge intended to fund state-mandated public benefit programs. These programs are typically funded through volumetric charges on electricity bills, which customers with DG systems can partially avoid through self-supply of electricity. Notably, the CBC is not intended to address utility fixed costs or other cost shift issues.

Table 15. National Grid Value Stack Summary

System Capacity Limit	5 MW
Aggregate Capacity Limit	None
Netting Interval	Hourly
Export Credit Rates	Monetary crediting based on Value Stack components – see NYSERDA Value Stack calculator[58]
Monthly Net Excess Generation	Carries over indefinitely
Fees	Monthly Customer Benefit Contribution (CBC) for systems installed beginning in 2022 ($1.15 per kW installed capacity for National Grid). Other charges depend on the customer's service rate.
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	Solar for All Program Affordable Solar NY-SUN Program NYSERDA financing programs
Energy Storage Provisions	Hybrid Tariff for DG plus storage systems
Utility or Aggregator System Control	N/A

The Public Service Commission estimated that charges would range from $0.69 to $1.09 per kW-AC per month for customers using Phase One Net Energy Metering Tariffs. The CBC differs depending on which electric utility serves the customer. National Grid's CBC filing, made in November 2020, set the CBC for standard residential customers at $1.15 per kW per month, although the Commission's estimated CBC value for National Grid had been $0.95 per kW per month. Value Stack customers will also pay the CBC, but at only half the rate charged to mass market customers. Although the CBC was approved in 2020, it will not go into effect until January 1, 2022, and the filed CBC value is not yet final.

[58] Solar Value Stack Calculator. New York State Energy Research and Development Authority. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator.

National Grid's standard residential service rate, SC-1, uses standard volumetric pricing without time-of-use components. The basic service charge of $17.00 cannot be offset with net metering credits; all other rate components can be offset.

Low- and Moderate-Income Customer Provisions

New York's Solar for All program provides qualifying residents with monthly bill credits from community distributed generation (CDG) projects.[59] The program is fully subscribed in National Grid territory.

NYSERDA also offers expanded solar installation incentives through the NY-SUN program for lower-income residents.[60] Financing options available through NYSERDA offer lower interest rates for low-income residents. NYSERDA offers an on-bill solar financing program and direct loan programs.

Energy Storage

New York has a "hybrid" tariff, adopted in 2018, for combined solar and storage systems. These systems use the Value Stack compensation method, with several compensation options available to ensure that customers do not receive environmental benefit-based portions of the Value Stack for injections of non-renewable electricity (this can occur if the customer charges the battery from the grid rather than the attached solar generation).

For residential customers, the state currently offers energy storage incentives for the Long Island Power Authority area. Commercial customers can receive incentives in other regions through the Retail Energy Storage Incentive program, a declining block program providing capacity-based one-time payments to storage developers. However, the retail storage incentive funding has been fully allocated for National Grid's service territory.[61]

New York offers a partial real property tax exemption for energy storage systems (and solar photovoltaic systems).[62] The exemption lasts for 15 years and exempts the added property value provided by the system from taxation. In May 2020, NYSERDA received approval to provide an additional incentive through the NY-SUN program to solar projects with paired storage systems.[63] However, the incentive program approved in that order is not yet available.

[59] Solar for All. New York State Energy Research and Development Authority (NYSERDA). https://www.nyserda.ny.gov/All%20Programs/Programs/NY%20Sun/Solar%20for%20Your%20Home/Community%20Solar/Solar%20for%20All.

[60] Residential Solar Incentives and Financing. NNYSERDA. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Solar-for-Your-Home/Paying-for-Solar/Incentives-and-Financing.

[61] Incentive Dashboard. NYSERDA. https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Developers-Contractors-and-Vendors/Retail-Incentive-Offer/Incentive-Dashboard.

[62] New York Consolidated Laws Article 4, Title 2, Section 487 - Exemption from taxation for certain energy systems. https://www.nysenate.gov/legislation/laws/RPT/487.

[63] New York Public Service Commission Case No. 19-E-0375. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=61254&MNO=19-E-0735.

South Carolina (Duke Energy)

Net Metering Successor Tariff Development

Legislation enacted in 2014 required Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion Energy to provide retail rate net metering with monthly netting.[64] DEC reached its 2% aggregate cap for net metering in the summer of 2018, and announced that it would cease offering net metering.[65] Effective August 2018, new customer-generators would only be able to sell energy produced by their systems through the Purchase Power Tariff (buy-all, sell-all program, crediting gross production at the avoided cost rate). During that same time, Duke Energy was engaged in discussions with the Office of Regulatory Staff and other stakeholders to reach consensus on recommended legislation for the General Assembly to consider in the next legislative session for a successor to net metering. Duke Energy filed a joint petition with all of the stakeholders in September 2018, agreeing to extend the availability of net metering until March 2019.[66]

Legislation enacted in 2019 extended the availability of traditional net metering for new customers of all three utilities until May 31, 2021, and allowed for grandfathering of these customers through May 31, 2029.[67] The legislation also required the Public Service Commission to develop a successor tariff, called the "solar choice metering tariff," to be implemented by June 1, 2021. The Public Service Commission opened new proceedings in the fall of 2020 to develop successor tariffs for each utility.[68] Utilities have presented their proposed successor tariffs, but as of February 2021, the Public Service Commission has not approved them.

DEC and DEP filed a joint application in November 2020 for approval of a successor tariff and transition plan it reached in a settlement agreement with a group of stakeholders, including representatives from the solar industry.[69] Duke Energy's proposed tariffs include monthly netting with time-of-use credit rates, a minimum bill, and charges based on the customer's DG system capacity. Dominion Energy included its proposed tariffs in testimony filed in December 2020. Dominion's proposed tariffs include 15-minute netting with avoided cost rate credits that vary by time of day, as well as increased basic facilities charges, and a monthly subscription charge.

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[64] South Carolina Act 236 (2014 Reg. Session). https://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm.
[65] *Duke Energy Carolinas Customers Lead South Carolina in Private Solar Adoption*. Duke Energy Press Release. July 12, 2018. https://news.duke-energy.com/releases/duke-energy-carolinas-customers-lead-south-carolina-in-private-solar-adoption.
[66] Joint Petition to Extend Net Metering Program and Request for Expedited Relief. South Carolina Public Service Commission Docket No. 2015-55-E. https://dms.psc.sc.gov/Attachments/Matter/67b2f64f-5a1a-4100-b634-055f97c6ba4c.
[67] South Carolina Act 62 (2019 Reg. Session). https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm.
[68] South Carolina Public Service Commission (PSC) Docket No. 2020-264-E (Duke Energy Carolinas). https://dms.psc.sc.gov/Web/Dockets/Detail/117615; South Carolina PSC Docket No. 2020-265-E (Duke Energy Progress). https://dms.psc.sc.gov/Web/Dockets/Detail/117616; South Carolina PSC Docket No. 2020-229-E (Dominion Energy). https://dms.psc.sc.gov/Web/Dockets/Detail/117571.
[69] Joint Application of DEC and DEP for Approval of Solar Choice Metering Tariffs. South Carolina Public Service Commission Docket Nos. 2020-264-E and 2020-365-E. https://dms.psc.sc.gov/Attachments/Matter/9dc8574f-5814-4466-aa0f-ca0df5eab87b.

Tariff Design

South Carolina's current net metering rules take the form of traditional net metering with retail rate compensation, monthly credit rollover, and a payout for any remaining net excess generation in March of every year at the avoided cost rate.[70] Customers may remain on this tariff until May 31, 2029.

Table 16. South Carolina Net Metering Summary

System Capacity Limit	Residential: 20 kW Commercial: 1 MW
Aggregate Capacity Limit	2% of the previous five-year average of the utility's South Carolina retail peak demand
Netting Interval	Monthly
Export Credit Rates	Retail rate
Monthly Net Excess Generation	Carries forward, with excess remaining at the end of the annual period credited to the customer at the avoided cost rate.
Fees	DEC Basic Facilities Charge: $11.96 DEP Basic Facilities Charge: $11.78 Dominion Energy Basic Service Charge: $9.00
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must be configured to receive electrical charge solely from an on-site renewable energy resource.
Utility or Aggregator System Control	N/A

Duke Energy

DEC and DEP filed a joint application in November 2020 for approval of a successor tariff and transition plan it reached in a settlement agreement with a group of stakeholders, including

[70] Rider RNM (DEC). https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/scridernm.pdf?la=en; Rider RNM (DEP). https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/rr20scridernm.pdf?la=en; Third NEM Rider (Dominion). https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/south-carolina/rates-and-tariffs/rider-to-retail-rates---third-net-energy-metering-for-renewable-energy-facilities.pdf?la=en&rev=1740fd321ce246d4b27805ff8b97d4e1&hash=92A064EC214EB768F86E5349F3DE8E0B.

representatives from the solar industry.[71] The utilities propose to place residential customers applying between June 1, 2021 and December 31, 2021 on Interim Tariffs. The Interim Tariff will be very similar to the currently approved net metering rider, but will include monthly netting with net exports credited at avoided cost; a non-bypassable charge based on DG system capacity to cover energy efficiency costs, cyber security costs, storm cost recovery, and similar costs; enrollment caps; and future service provisions.

Residential customers applying after December 31, 2021 and non-residential customers applying after May 31, 2021 would be placed on permanent Solar Choice Metering Tariffs. The residential tariffs feature time-of-use rates with four separate monthly netting periods: critical peak, peak, off-peak, and super off-peak. Exports to the grid during each time period will be netted against imports to the grid during that same period, with the exception that critical peak exports can only be used to offset peak imports, not critical peak imports. The proposed non-residential solar choice tariff includes monthly netting, with credits applied at the customer's regular applicable rate schedule. For both residential and non-residential customers, net exports remaining at the end of the month will be compensated at avoided cost.

Table 17. Duke Energy Proposed Residential TOU Credits

	Time-of-Day Period	DEC Rate ($/kWh)	DEP Rate ($/kWh)
Critical Peak	On-peak times on days the company has designated Critical Peak Pricing Days. The Company will call up to 20 Critical Peak Pricing (CPP) Days per calendar year	0.25	0.25
On-Peak	Monday - Friday, 6:00 PM to 9:00 PM (year round); Monday - Friday, 6:00 AM to 9:00 AM (December through February only)	0.151760	0.15843
Off-Peak	All other times	0.087586	0.09529
Super Off-Peak	12:00 AM - 6:00 AM (March through November)	0.060268	0.06994

The residential tariffs also include a $30 monthly minimum bill, a non-bypassable charge based on DG system capacity, and a Grid Access Fee (GAF) also based on DG system capacity for solar facilities with a capacity greater than 15 kW-DC. The initial GAF will be applied to all capacity in excess of 15 kW-DC at a rate of: $5.86/kW-DC per month for DEC and $3.95/kW-DC per month for DEP. The non-bypassable charge is designed to recover all costs related to demand-side management and energy efficiency, storm cost recovery, and cyber security. Non-bypassable cost recovery will be a monthly charge per kW-DC of the customer-generator's system capacity at a rate of $0.42/kW-DC per month for DEC and $0.49/kW-DC per month for

[71] Joint Application of DEC and DEP for Approval of Solar Choice Metering Tariffs. South Carolina Public Service Commission Docket Nos. 2020-264-E and 2020-365-E. https://dms.psc.sc.gov/Attachments/Matter/9dc8574f-5814-4466-aa0f-ca0df5eab87b.

DEP. The tariffs also include slightly higher basic facilities charges than the standard residential customer tariffs.

Table 18. Duke Energy Proposed Solar Choice Metering Tariff Summary

System Capacity Limit	Residential: 20 kW Commercial: 1 MW
Aggregate Capacity Limit	None
Netting Interval	Residential: Time-of-use periods netted monthly. Consumption during one time-of-use period will offset consumption during that time period, with the exception of critical peak. Non-Residential: Monthly
Export Credit Rates	Residential: Time-varying credit rates (see Table 17) Non-Residential: Retail rates on applicable service tariff
Monthly Net Excess Generation	Monthly net excess generation within any time-of-use period will be credited at a rate of $0.023 per kWh (DEP) or $0.027 per kWh (DEC).
Fees	Residential Charges: Minimum Bill: $30 Basic Facilities Charge (DEP): $14.63 Basic Facilities Charge (DEC): $13.09 Grid Access Fee (DEP): $3.95 per kW installed capacity above 15 kW Grid Access Fee (DEC): $5.86 per kW installed capacity above 15 kW Non-Bypassable Charge (DEP): $0.49 per kW installed capacity Non-Bypassable Charge (DEC): $0.42 per kW installed capacity
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must be configured to receive electrical charge solely from an on-site renewable energy resource.
Utility or Aggregator System Control	N/A

The settlement agreement Duke Energy signed with multiple stakeholders in 2020 also included a $0.36/Watt-DC incentive for new residential Solar Choice tariff customers who enroll in a proposed winter smart thermostat program. The smart thermostat program also offers an additional upfront $75 bill credit and then an annual bill credit of $25. This element of the agreement was not included in the application filed by Duke Energy. In a footnote in the application, Duke Energy explains that it intends to file for approval of that program separately.

Dominion Energy

Dominion Energy's proposed tariffs are based on net billing within a time-of-use structure with a summer peak, winter peak, and off peak times.[72] Inflows and outflows would be netted in 15-minute intervals. These 15-minute measurements are then aggregated within the month by time-of-use billing period, and the applicable rate is applied to those cumulative amounts by time-of-use period for both customer usage and exports. Exported power would be credited at a time-varying avoided energy rate.

Table 19. Dominion Energy Proposed Solar Choice Metering Tariff Summary

System Capacity Limit	Residential: 20 kW Commercial: 1 MW
Aggregate Capacity Limit	None
Netting Interval	15-minute netting by TOU period
Export Credit Rates	Time-varying credit rates: Summer On-Peak: $0.03651 per kWh Winter On-Peak: $0.03796 per kWh All Off-Peak: $0.03622 per kWh
Monthly Net Excess Generation	Monetary credit applied monthly
Fees	Basic Facilities Charge (Residential): $19.50 Basic Facilities Charge (Small General Service): $32.50 Subscription Fee (Residential): $5.40 per kW installed DG capacity Subscription Fee (Small General Service): $6.50 per kW installed DG capacity
REC Ownership	Utility owns RECs
Low- and Moderate Income Customer Provisions	N/A
Energy Storage Provisions	Allowed, must be configured to receive electrical charge solely from an on-site renewable energy resource.
Utility or Aggregator System Control	N/A

Dominion's proposed residential on-peak hours are 5:00 AM to 9:00 AM during winter months (December through February) and 4:00 PM to 8:00 PM during summer months (June through

[72] Direct Testimony of Allen W. Rooks. South Carolina Public Service Commission Docket No. 2020-229-E. https://dms.psc.sc.gov/Attachments/Matter/c650b3a1-d9cf-4752-925c-e33f94a01e9e.

September). The on-peak winter energy charge is $0.18417 per kWh, and the on-peak summer energy charge is $0.16749. The off-peak energy charge is $0.06735. The proposed on-peak winter credit rate is $0.03796, the on-peak summer credit rate is $0.03651, and the off-peak credit rate is $0.03622.

The tariffs also include a basic facilities charge of $19.50 for residential customers and $32.50 for small general service customers. Dominion's current basic facilities charge is $9.00 for standard residential customers and $19.50 for standard general service customers.[73] The tariffs also include a "subscription fee" of $5.40 per installed kW for residential customers and $6.50 per installed kW for small general service customers. The subscription fee is intended to recover transmission and distribution costs.[74]

Energy Storage

Legislation enacted in 2019 authorized net metering for generation paired with energy storage, as long as the storage facility is configured to charge solely by the renewable energy resource. The state does not currently offer any incentives for energy storage systems.

[73] South Carolina Rates & Tariffs. Dominion Energy. https://www.dominionenergy.com/south-carolina/rates-and-tariffs.
[74] Direct Testimony of Allen W. Rooks. South Carolina Public Service Commission Docket No. 2020-229-E. https://dms.psc.sc.gov/Attachments/Matter/c650b3a1-d9cf-4752-925c-e33f94a01e9e.

Solar Payback Period Analysis

The following payback period analyses use the National Renewable Energy Laboratory's System Advisor Model to estimate the simple payback period for a residential customer-owned 5 kW solar photovoltaic system in eight different utility territories. The analysis uses a 20-year period and assumes that the customer makes a cash purchase for the system.

System cost data for Arizona, California, Nevada, New York, and South Carolina comes from online solar marketplace EnergySage (2020 median prices by state) and Lawrence Berkeley National Laboratory's *Tracking the Sun* report.[75] Tracking the Sun includes system cost data for all of the states examined except South Carolina. EnergySage and Tracking the Sun do not include cost data for Hawaii, so upfront cost data comes from SolarReviews.[76] Battery costs for a solar-plus-storage system including a 5 kW / 13 kWh battery participating in Hawaii's Smart Export tariff are based on market estimates from EnergySage.[77] The analysis also assumes insurance costs of 0.5% of installed costs per year and O&M costs of $20/kW per year.

The analysis includes the current 26% federal investment tax credit, as well as any currently available state or utility incentives, such as sales tax exemptions, property tax exemptions, tax credits, and rebates. A 2% annual inflation rate is applied, including to electricity prices. Customer load data comes from OpenEI and uses low, base, and high load cases. The data assumes electric or gas heating based on U.S. EPA climate zone.[i]

Note that payback period can vary significantly based on system cost and customer energy use patterns.

Installed Capacity

Installed capacity data comes from the U.S. Energy Information Administration's (EIA) Form 861M.[78] Monthly data for residential solar PV and total net-metered solar PV by utility is included for January 2013 through November 2020. To examine the potential impact of net metering reforms on solar adoption rates, the analysis compares the average monthly residential net-metered solar capacity additions for the 12-month period preceding the reform to that of the 12-month period following the reform. To express installed capacity as a percentage of utility peak demand, EIA Form 861 operational data from 2019 is used.[ii] The percentage of total residential customers that participate in solar net metering is also presented, using data from EIA's Forms 861M and 861 Sales and Utility Customers.

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[75] Galen Barbose, Naim Darghouth, Eric O-Shaughnessy, and Sydney Forrester. Lawrence Berkeley National Laboratory. *Tracking the Sun Distributed Solar 2020 Data Update*. December 2020. https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf

[76] How much do solar panels cost in Hawaii, 2021? SolarReviews. https://www.solarreviews.com/solar-panel-cost/hawaii#:~:text=Solar%20panel%20cost%20Hawaii%3A%20Prices%20%26%20data%20February%202021&text=As%20of%20Feb%202021%2C%20the,solar%20tax%20credit%20now%20available.

[77] *How much does solar storage cost? Understanding solar battery costs.* EnergySage. August 31, 2020. https://www.energysage.com/solar/solar-energy-storage/what-do-solar-batteries-cost/.

[78] U.S. Energy Information Administration. Form 861-M Detailed Data – Net Metering. 2013 – 2020. https://www.eia.gov/electricity/data/eia861m/.

Table 20. Summary of Payback Period and Installed Capacity Analysis

Utility	Payback Period – ES Base Case (Yrs)	Payback Period – TTS Base Case (Yrs)	Nov. 2020 Installed Resi. NEM PV (MW)	Nov. 2020 Installed C&I NEM PV (MW)	Resi. NEM % 2019 Peak Demand	Total NEM % 2019 Peak Demand	% Resi. NEM Customer Participation
APS	9.6	14.4	940.53	301.89	13.2%	17.5%	10.2%
PacifiCorp (CA)	>20	>20	4.19	5.01	**	**	1.5%
LADWP (Zone 1)	6.6	8.9	270.61	115.91	4.8%	6.9%	3.7%
LADWP (Zone 2)	7.1	9.6	270.61	115.91	4.8%	6.9%	3.7%
SMUD	12.9	17.3	144.38	97.82	4.9%	8.3%	5.8%
HECO Utilities – CGS+	6.0*		405.59	112.78	25.6%	32.7%	16.0%
HECO Utilities – Smart Export	9.0*		405.59	112.78	25.6%	32.7%	16.0%
NV Energy	11.6	18.5	413.38	78.07	5.6%	6.6%	5.3%
National Grid (NY) – Mass Market	11.3	14.1	142.61	277.27	2.5%	7.2%	1.5%
Duke Energy (SC)	19.3	N/A*	75.58	32.64	**	**	1.4%

* Cost data for Hawaii is unavailable from EnergySage and Tracking the Sun. The Hawaii analysis uses average system cost data from SolarReviews. Tracking the Sun does not include cost data for South Carolina.

** EIA does not include peak demand data specifically for PacifiCorp's California service territory and Duke Energy's South Carolina service territory.

Table 21. Residential Solar Adoption Before and After Net Metering Reforms

Utility	NEM Reform Date	Avg. Monthly Capacity Additions Before NEM Reform (MW/Month for 12 Months Preceding Reform)	Avg. Monthly Capacity Additions After NEM Reform (MW/Month for 12 Months Following Reform)
Arizona Public Service	Sept. 2017	9.36	16.30
PacifiCorp (CA)	Mar. 2020	0.05	0.025*
HECO (CSS / CGS)	Oct. 2015	4.04	4.06
HECO (CGS+ / Smart Export)	Feb. 2018	0.97	0.43
NV Energy (Net Billing)	Jan. 2016	6.33	3.37
NV Energy (Net Metering)	Sept. 2017	0.96	3.36
National Grid (NY) – Phase One NEM / VDER	Mar. 2017	1.99	1.48

* Average monthly capacity additions for Mar. – Nov. 2020

Arizona (Arizona Public Service)

Location: Phoenix, AZ

Tariff: Three options:

- Saver Choice R-TOU-E[iii]– Basic service charge of $0.427 per day, TOU rates (on-peak, off-peak, super off-peak, DG Grid Access Charge of $0.93 per kW of DG
- Saver Choice R-2[iv] – Basic service charge of $0.427 per day, TOU rates (on-peak, off-peak), on-peak demand charge ($8.40 per kW)
- Saver Choice R-3[v] – Basic service charge of $0.427 per day, TOU rates (on-peak, off-peak), on-peak demand charge (summer: $17.438 per kW, winter: $12.239 per kW)

Net Metering Tariff: Resource Comparison Proxy (RCP) Export Rider[vi]

- Instantaneous netting period. Current export credit rate of $0.1045 per kWh – credit is locked in for 10 years *(Note: analysis uses this rate for the full 20 years)*

Sales Tax Rate: 0% (State exemption)

Property Tax Rate: 0% (State exemption)

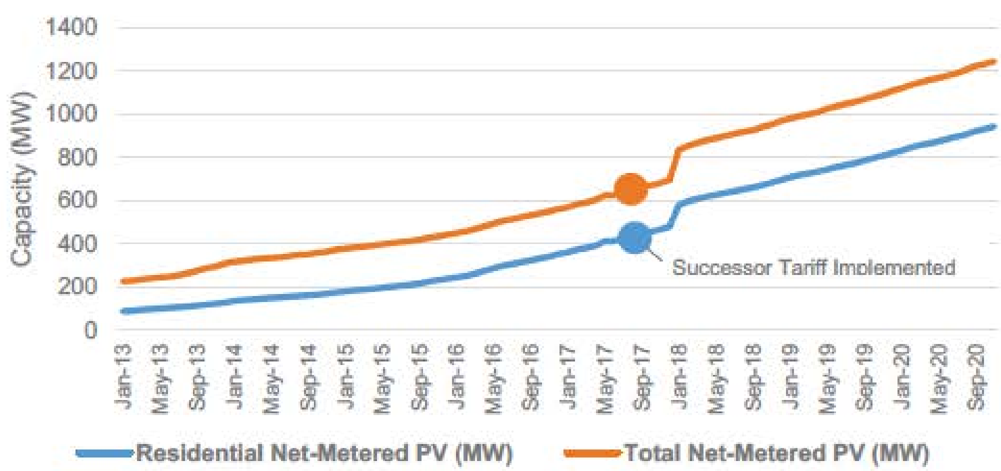
State Incentives: Residential Solar and Wind Energy Systems Tax Credit (25% up to $1,000)

System Cost: $2.47 (EnergySage); $3.60 (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
			R-TOU-E			
Simple Payback (Years)	9.5	14.2	9.2	13.8	9.2	13.9
			R-2			
Simple Payback (Years)	10.7	16.2	11.5	17.4	11.9	18.0
			R-3			
Simple Payback (Years)	11.8	17.8	14.2	>20	15.8	>20

Installed Capacity:

Arizona Public Service had 940.53 MW of residential net-metered solar PV capacity and 1,242.42 MW of total net-metered solar PV capacity as of November 2020.



California (PacifiCorp)

Location: Crescent City, CA
Tariff: Residential Service[vii]

- Basic charge of $7.53
- Flat energy rate

Net Metering Tariff: Net Billing Service NB-136[viii]

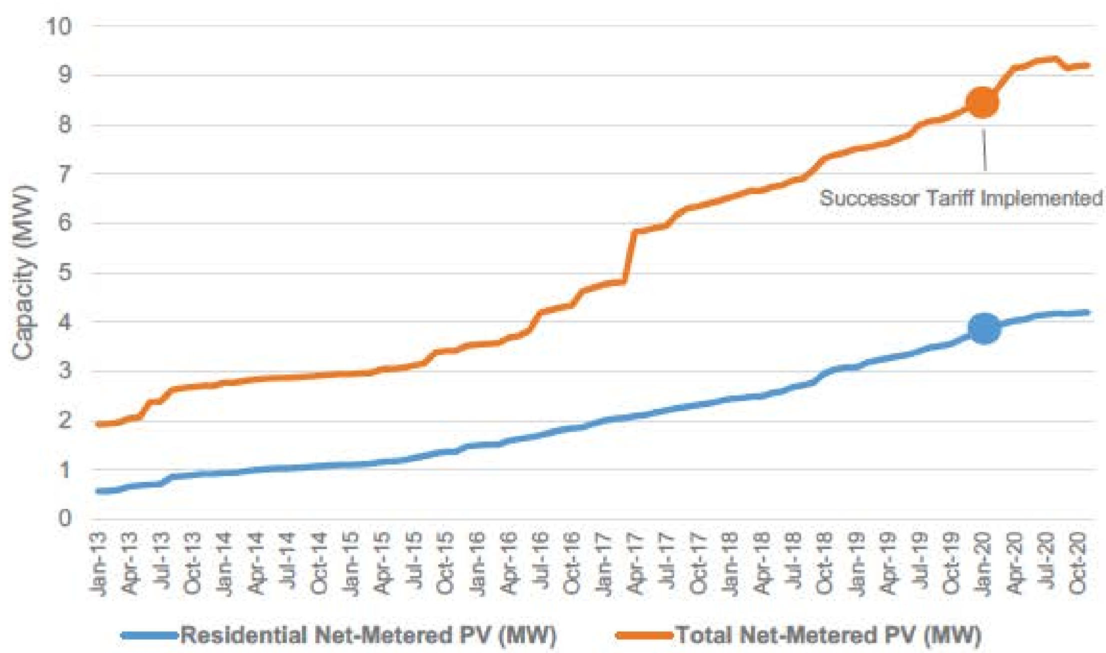
- Export credit rate of 4.865 cents per kWh for on-peak energy and 3.699 cents per kWh for off-peak energy

Sales Tax Rate: 0% (State exemption)
Property Tax Rate: 0% (State exemption)
System Cost: $2.82/W (EnergySage); $3.80 (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Simple Payback (Years)	>20	>20	>20	>20	>20	>20

Installed Capacity:

PacifiCorp had 4.19 MW of residential net-metered solar PV capacity and 9.20 MW of total net-metered solar PV capacity in its California service territory as of November 2020.



California (Los Angeles Department of Water & Power)

Location: Los Angeles, CA
Tariff: Standard Residential Rate (R-1A)[ix]

- Tiered energy rates with seasonal variation *(analysis uses 2020 rates for June-Sept. period, as 2021 rates are not yet available)*
- Power access charge ($2.60 to $22.70, depending on usage)
- Minimum bill of $10

Net Metering Tariff: NEM – Net Energy Metering[x]

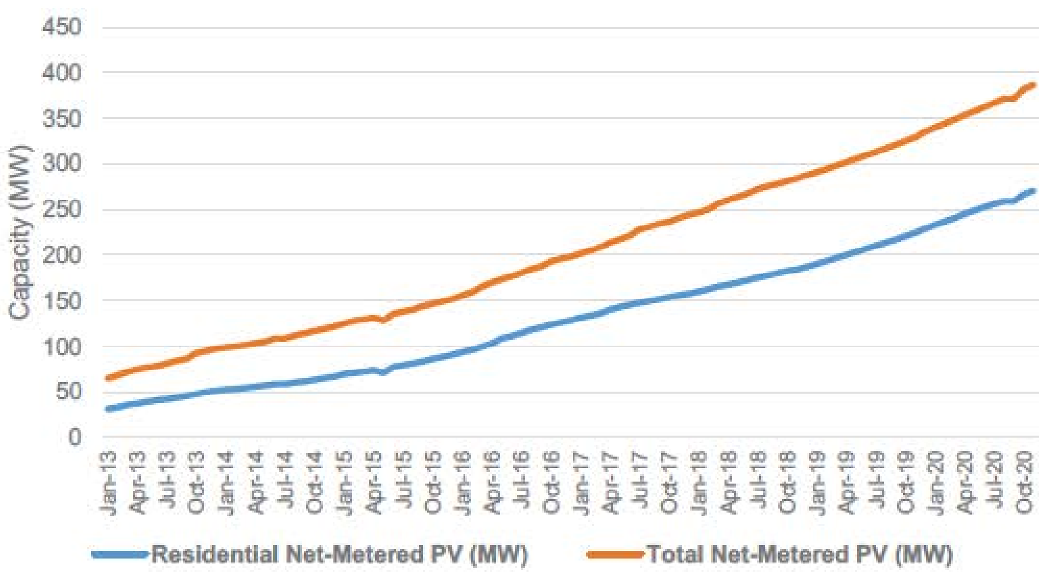
- Retail rate net metering
- Net excess generation may carry forward indefinitely

Sales Tax Rate: 0% (State exemption)
Property Tax Rate: 0% (State exemption)
System Cost: $2.82/W (EnergySage); $3.80 (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Zone 1 Simple Payback (Years)	8.1	11.0	6.6	8.9	5.4	7.3
Zone 2 Simple Payback (Years)	8.2	11.0	7.1	9.6	6.0	8.1

Installed Capacity:

The Los Angeles Department of Water & Power had 270.61 MW of residential net-metered solar PV capacity and 386.52 MW of total net-metered solar PV capacity as of November 2020.



California (Sacramento Municipal Utility District)

Location: Sacramento, CA
Tariff: Residential Time-of-Day Service (R-TOD)[xi]

- System infrastructure fixed charge of $22.25
- TOU rates (summer peak, summer mid-peak, summer off-peak, non-summer peak, non-summer off-peak)

Net Metering Tariff: NEM1[xii]

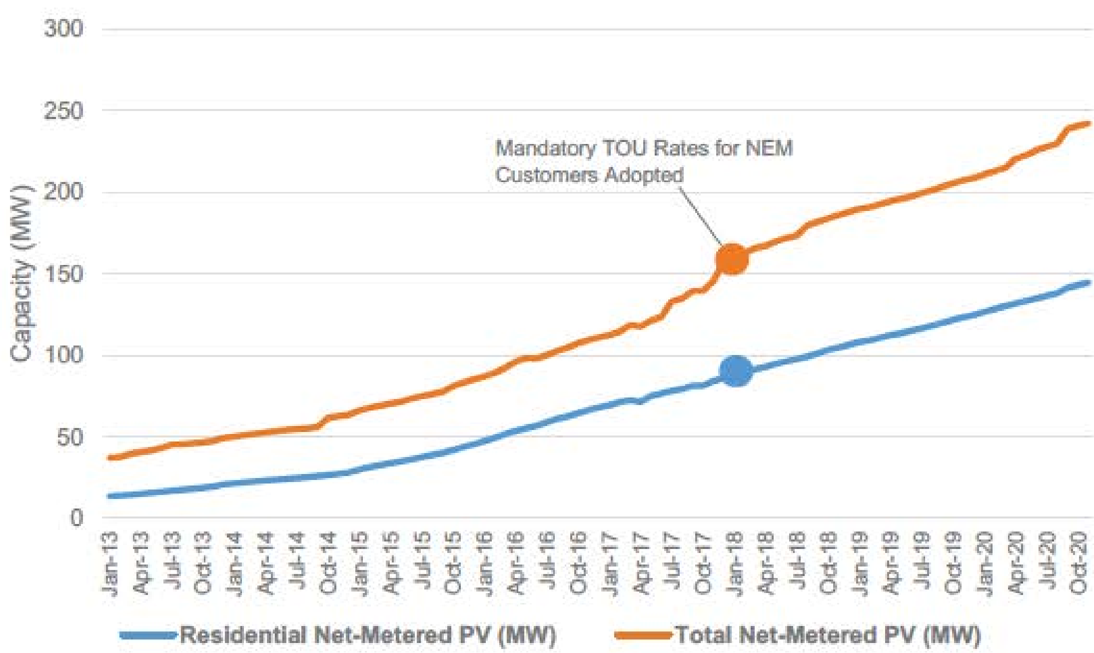
- Retail rate net metering with mandatory TOU rates
- Annual net excess generation may be paid out at 5.62 cents/kWh or carried forward
- Customers will be subject to NEM successor tariff currently under development

Sales Tax Rate: 0% (State exemption)
Property Tax Rate: 0% (State exemption)
System Cost: $2.82/W (EnergySage); $3.80 (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Simple Payback (Years)	17.8	>20	12.9	17.3	11.7	15.8

Installed Capacity:

The Sacramento Municipal Utility District had 144.38 MW of residential net-metered solar PV capacity and 242.20 MW of total net-metered solar PV capacity as of November 2020.



Hawaii (Hawaiian Electric Company)

Location: Honolulu, HI (Island of Oahu)
Tariff: Schedule R – Residential Service[xiii]

- Customer charge of $11.50 (plus green infrastructure fee of $1.25) and minimum charge of $25.00, tiered energy rates

Net Metering Tariffs:

- Legacy Net Metering[xiv] (retail rate net metering)
- Customer Grid Supply Plus[xv] (export credit rate of 10.08 cents per kWh, island of Oahu)
- Smart Export[xvi] (export credit rate of 14.97 cents per kWh, island of Oahu; no credit for 4pm to 9am)

Sales Tax Rate: 4.5%[xvii]
Property Tax Rate: 0% (City of Honolulu Alternative Energy Property Tax Exemption)
State Incentives: Solar and Wind Energy Tax Credit (35% up to $5,000)
System Cost: Solar PV: $3.77/W (SolarReviews)[xviii]; Battery: $13,000 for 5 kW / 13 kWh (based on EnergySage market estimates)[xix]

Oahu (HECO) Simple Payback Summary

Electric Load	Low Load Profile	Base Load Profile	High Load Profile
Legacy Net Metering (Closed to new customers)			
Simple Payback (Years)	5.5	4.5	4.3
Customer Grid Supply Plus			
Simple Payback (Years)	8.2	6.0	4.7
Smart Export			
Simple Payback (Years)	11.2	9.0	8.2

Other Islands Payback Summary

Electric Load	Low Load Profile	Base Load Profile	High Load Profile
Customer Grid Supply Plus (Simple Payback in Years)			
Hawaii Island (HELCO)	6.9	5.0	4.0
Maui (MECO)	7.1	5.4	4.5
Molokai (MECO)	6.1	5.1	4.4
Lanai (MECO)	5.7	5.0	4.4
Smart Export (Simple Payback in Years)			
Hawaii Island (HELCO)	9.3	7.3	8.2
Maui (MECO)	10.4	8.3	7.8
Molokai (MECO)	10.4	8.3	7.8
Lanai (MECO)	10.3	8.3	7.8

Other Islands' Export Credit Rates:

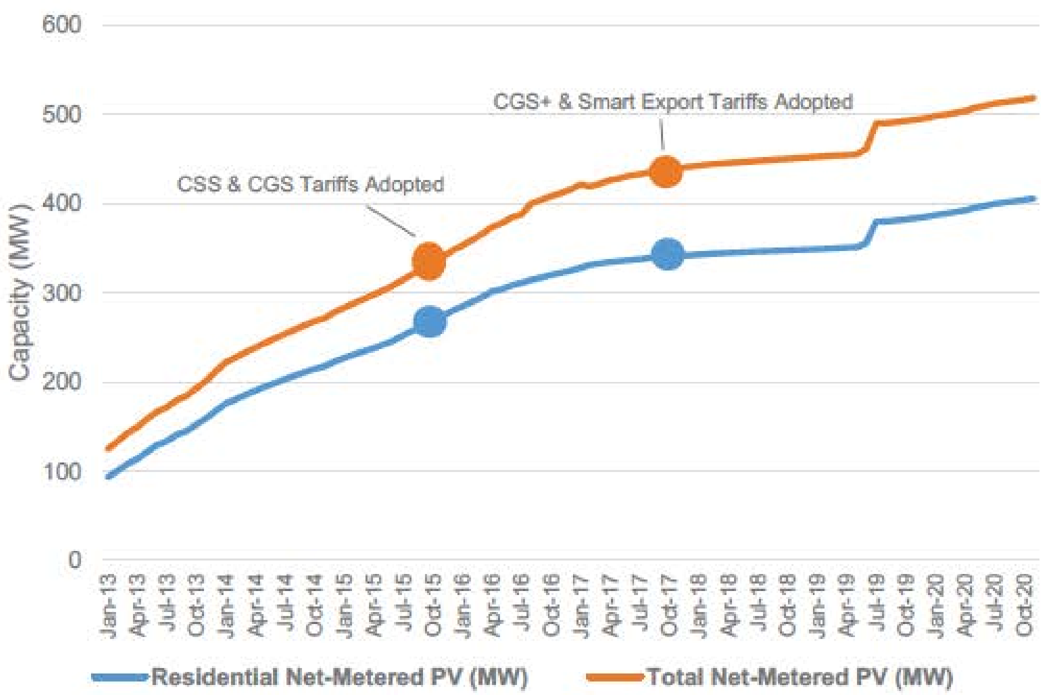
- Customer Grid Supply Plus:
  - ☐ Hawaii Island (HELCO) – 10.55 cents per kWh
  - ☐ Maui (MECO) – 12.17 cents per kWh
  - ☐ Molokai (MECO) – 16.77 cents per kWh
  - ☐ Lanai (MECO) – 20.80 cents per kWh
- Smart Export:
  - ☐ Hawaii Island (HELCO) – 11.00 cents per kWh
  - ☐ Maui (MECO) – 14.41 cents per kWh
  - ☐ Molokai (MECO) – 16.64 cents per kWh
  - ☐ Lanai (MECO) – 20.79 cents per kWh

Other Islands' Tariffs:

- Residential Service tariff, including customer charge of $11.50 (plus green infrastructure fee of $1.25) and minimum charge of $25.00
- Tiered energy rates vary for HECO, HELCO, and MECO

Installed Capacity:

The HECO Utilities (HECO, MECO, and HELCO) had 405.59 MW of residential net-metered solar PV capacity and 518.38 MW of total net-metered solar PV capacity as of November 2020.



Nevada (NV Energy)

Location: Las Vegas, NV
Tariff: Schedule RS - Residential Service[xx]

- Basic service charge of $12.50
- Flat energy rates (10.62 cents/kWh)

Net Metering Tariff: NMR-405[xxi]

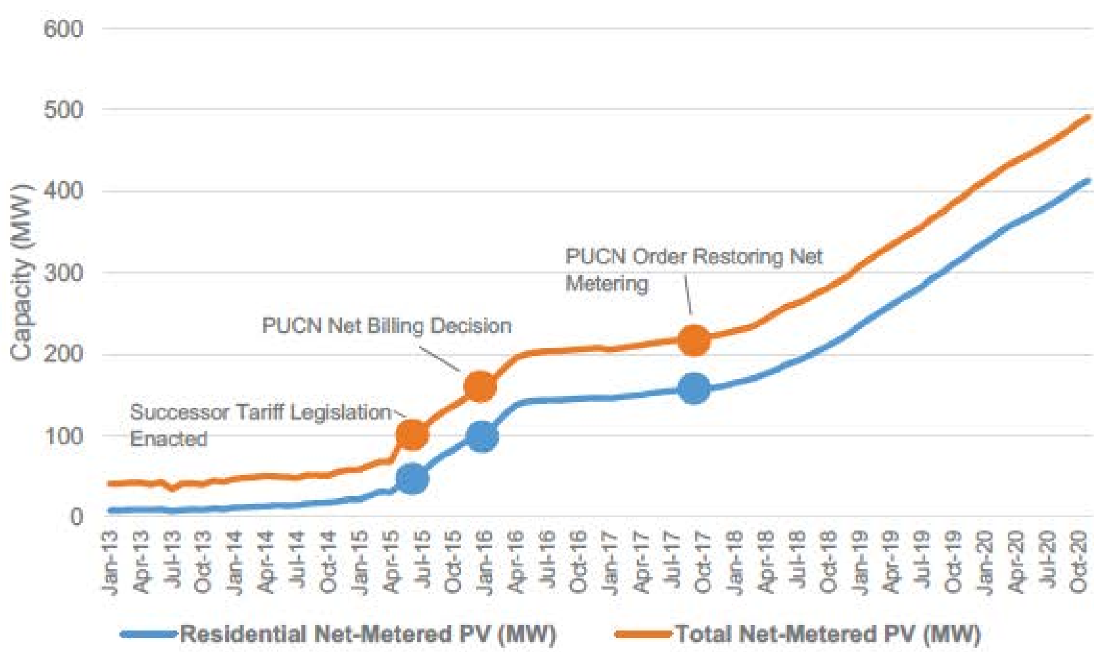
- Retail rate net metering
- Monthly net excess generation credited at 75% of retail rate (Tier 4) – rate applies for 20 years

Sales Tax Rate: 2.6% (State Renewable Energy Sales & Use Tax Abatement)
Property Tax Rate: 0% (State exemption)
System Cost: $2.52/W (EnergySage); $4.00/W (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Simple Payback (Years)	12.8	>20	11.6	18.5	11.5	18.3

Installed Capacity:

NV Energy had 413.38 MW of residential net-metered solar PV capacity and 491.45 MW of total net-metered solar PV capacity as of November 2020.



New York (National Grid)

Location: Buffalo, NY
Tariff: Residential and Farm Service (S.C. No. 1)[xxii]

- Basic service charge and minimum bill of $17.00
- Flat energy rates[xxiii]

Net Metering Tariff: NY PSC Decision Issued 7/16/2020 in Case No. 15-E-0751[xxiv]

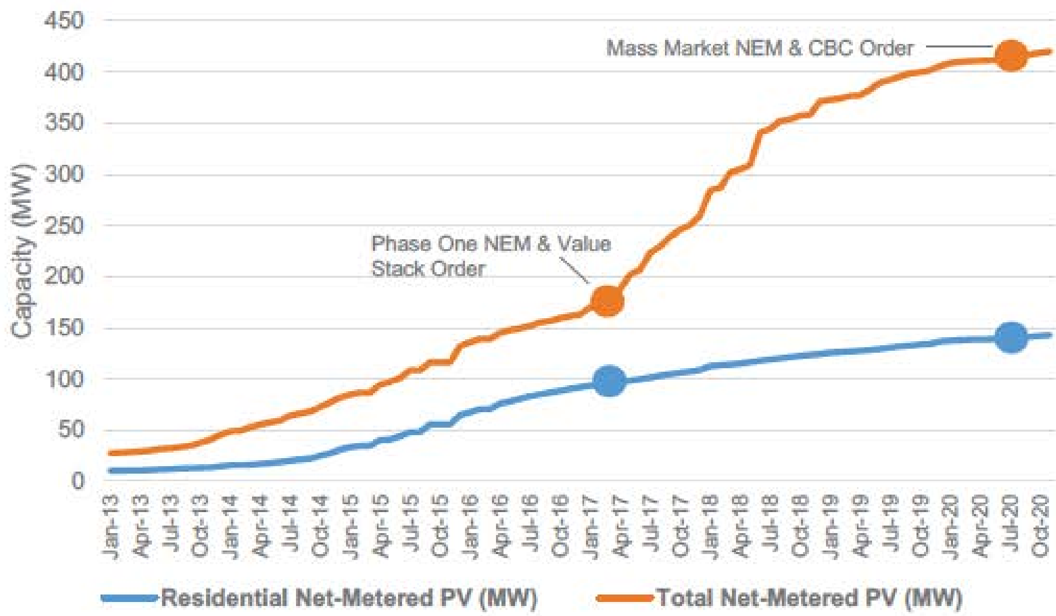
- Mass Market successor tariff to take effect in 2022
- Retail rate net metering
- Includes $1.15 per kW-DC customer benefit contribution

Sales Tax Rate: 0% (State exemption)
Property Tax Rate: 0% for 15 years (state exemption)
State Incentives: Residential Solar Tax Credit (25% up to $5,000), NY-Sun Solar Rebate ($0.35/W for Tranche 8 upstate region residential systems)[xxv]
System Cost: $3.25/W (EnergySage); $3.90/W (Tracking the Sun)

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Simple Payback (Years)	11.3	14.1	11.3	14.1	11.3	14.1

Installed Capacity:

National Grid had 142.61 MW of residential net-metered solar PV capacity and 419.89 MW of total net-metered solar PV capacity in its New York service territory as of November 2020.



South Carolina (Duke Energy Carolinas)

Location: Greenville, SC
Tariff: Residential Service, Solar Time-of-Use *(Proposed)*[xxvi]

- TOU rates (on-peak, off-peak, super off-peak)
- Critical peak pricing (up to 20 times per year) – *Note: not included in payback analysis, assumes on-peak pricing during critical peak events*
- Minimum bill of $30 and non-bypassable charge of $0.42 per kW-DC generation

Net Metering Tariff: Residential Solar Choice *(Proposed)*[xxvii]

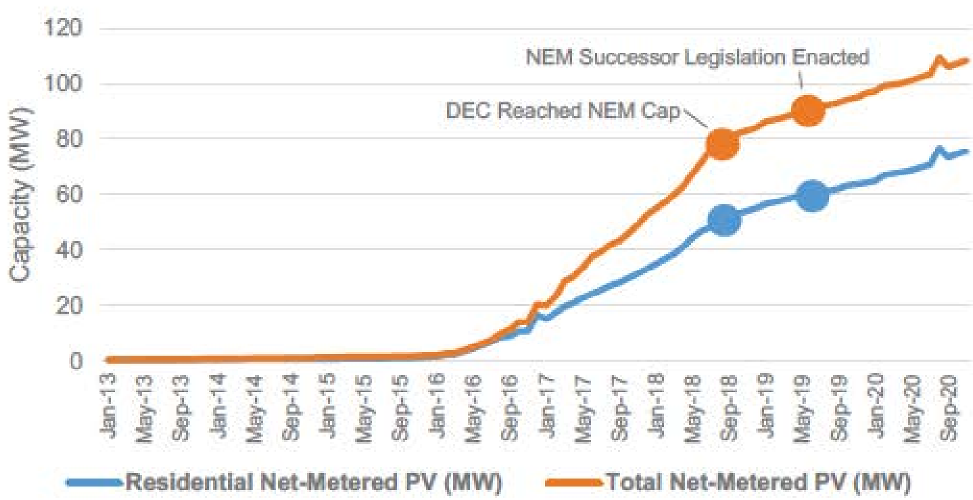
- Time-of-use net metering
- Monthly net excess generation credit rate of $0.027 per kWh

Sales Tax Rate: 6%[xxviii]
Property Tax Rate: 0.69%[xxix]
State & Utility Incentives: Solar, Energy, Small Hydropower, and Geothermal Tax Credit (25% up to $3,500); Upfront incentive of $0.36/W (up to 5 kW) if enrolling in smart thermostat program *(Proposed)*
System Cost: $3.26/W (EnergySage); Tracking the Sun data not available for SC

Electric Load	Low Load Profile		Base Load Profile		High Load Profile	
System Cost	EnergySage	TTS	EnergySage	TTS	EnergySage	TTS
Simple Payback (Years)	>20	N/A	19.3	N/A	19.0	N/A

Installed Capacity:

Duke Energy (Carolinas and Progress) had 75.58 MW of residential net-metered solar PV capacity and 108.22 MW of total net-metered solar PV capacity in its South Carolina service territory as of November 2020.



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