FILED
03/15/21
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

JOINT PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

STEVEN W. FRANK
Pacific Gas and Electric Company
77 Beale St., Mail Code B30A
San Francisco, CA 94105
Telephone: (415) 973-6976
Facsimile: (415) 973-0516
Email: steven.frank@pge.com

Attorney for
Pacific Gas and Electric Company

E. GREGORY BARNES
San Diego Gas & Electric Company
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1583
Facsimile: (619) 699-5027
Email: gbarnes@sdge.com

Attorney for
San Diego Gas & Electric Company

JANET S. COMBS
REBECCA MEIERS-DEPASTINO
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
Telephone: (626) 302-6016
Email: Rebecca.Meiers.Depastino@sce.com

Attorneys for
Southern California Edison Company

Dated: March 15, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

JOINT PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

Pursuant to the November 19, 2020 Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruing Directing Comments on Proposed Guiding Principles, as well as the March 5, 2021 email ruling of Administrative Law Judge Hymes, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (collectively, the Joint Utilities), hereby file their Joint Proposal for reform to the net energy metering tariffs. The Joint Proposal is provided as Attachment A.

As requested in the March 5, 2021 email ruling, the Joint Utilities have designated the following representatives to present the Joint Proposal at the workshop on March 23-24, 2021:

- Representing PG&E: Erica Brown (erica.brown@pge.com);
- Representing SDG&E: Gwen Morien (gmorien@sdge.com); and
- Representing SCE: Robert Thomas (Robert.Thomas@sce.com).

The Joint Utilities propose that Ms. Brown lead the presentation for the Joint Utilities, with support from Ms. Morien and Mr. Thomas as may be appropriate. Email inquiries for all three individuals can be directed to a shared email inbox: DGSTProposal@sce.com.

Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, PG&E has been authorized by representatives of SDG&E and SCE to submit this filing on their behalf.

Respectfully Submitted,

By: */s/ Steven Frank*
STEVEN W. FRANK

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6976
Facsimile: (415) 973-0516
E-Mail: steven.frank@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: March 15, 2021

ATTACHMENT A

NET ENERGY METERING REFORM PROPOSAL OF PG&E, SDG&E AND SCE TO ACHIEVE AN AFFORDABLE, SUSTAINABLE AND EQUITABLE CLEAN ENERGY FUTURE

California Public Utilities Commission

Rulemaking 20-08-020

March 15, 2021

TABLE OF CONTENTS
(continued)

NET ENERGY METERING REFORM PROPOSAL OF PG&E, SDG&E AND SCE TO ACHIEVE AN AFFORDABLE, SUSTAINABLE AND EQUITABLE CLEAN ENERGY FUTURE.

I. EXECUTIVE SUMMARY

California enacted Net Energy Metering (NEM) legislation in 1995 to create a subsidy that would, among other things, "encourage private investment in renewable energy resources, stimulate in-state economic growth, [and] enhance the continued diversification of California's energy resource mix…."[1/] The original statute has undeniably served its purpose.

Over the last 25 years, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (collectively, the Joint IOUs) have interconnected significant volumes of NEM behind-the-meter renewable generation, comprised primarily of solar photovoltaic (PV) "rooftop solar" systems. While the original legislation capped the program's peak load at 0.1%, today, rooftop solar comprises 25% of peak load for PG&E, 33.1% for SDG&E and 16.1% for SCE.[2/] The market for solar rooftop has not only matured, but also has grown to be robust. The cost of panels has significantly dropped, greenhouse gas emissions have been reduced by the proliferation of utility-scale and customer-sited renewable resources, and customers have more green energy choices. The Joint IOUs are proud to have been part of this progress and to continue to support California's important and ambitious climate change and greenhouse gas reduction efforts.

The program has continued to be wildly successful through the moderate reforms the California Public Utilities Commission (CPUC or Commission) already implemented under Assembly Bill (AB) 327 in 2016. Now that the original legislative objectives have been satisfied, the Joint IOUs look forward to supporting the Commission's and stakeholders' continuing efforts to implement the reforms required by AB 327 that will allow the state to responsibly manage the continued growth in rooftop solar, especially among underserved customers who historically have had less access to solar.

Reform is necessary because the existing NEM program has several drawbacks, largely because the program has not been revised significantly since its inception over two decades ago. The Joint IOUs have dedicated substantial time and resources over the past two years to better understand these issues and, where possible, quantify them. These issues include the following:

1. **The existing NEM program results in a $3.0 billion[3/] and growing cost shift each year from participants to non-participants, resulting in an average bill increase of over $200 each year for non-participating customers in SDG&E's territory.** Because

1/ California Public Utilities Code § 2827(a).

2/ Although most NEM exports are not treated as "generation" for renewable portfolio standard (RPS) targets or other planning purposes, 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.

3/ Calculated under the rates effective as of March 1, 2021.

participants tend to be wealthier single-family homeowners,[4/] this shift disproportionately hurts low- and middle-income customers.

2. **The existing NEM program's compensation structure is more generous than it needs to be**. Over the past two decades, while solar installation costs have decreased, NEM compensation has increased. Customers today will be paid back for their systems within five years,[5/] even though they are guaranteed additional subsidies for 20 years.

3. **The existing NEM program jeopardizes California climate goals, including building and transportation electrification**. The massive NEM program cost shift raises electricity rates for non-participants, creating a disincentive for electricity use. This makes adoption of technologies like heat pumps and electric vehicles less cost-effective and less attractive to customers.

4. **Adoption continues to lag among income-qualified customers compared to higher-income customers.** Because the NEM program is tied to retail rates, the program provides a better value proposition for higher-income customers than those income-qualified customers on discounted rate plans (e.g., California Alternate Rates for Energy, or "CARE," program).

5. **The existing NEM program does not provide price signals to promote more modern technologies and uses.** For the majority of IOU rates, there is insufficient differentiation between onsite use and exports, and insufficient price differentials for exported energy during the least- and most-valuable times of day.

While this proposal does not suggest changes for existing NEM customers, the Joint IOUs have worked extensively and collaboratively to fix the drawbacks of the existing NEM program on a forward-looking basis. The Joint IOUs have drawn on internal expertise from their customer program, rate, policy, electric operation, and billing teams. The Joint IOUs have learned from the Commission-directed efforts of the Lookback Study and the E3 White Paper. The Joint IOUs have also drawn on external expertise through consultation with environmental, consumer, and income-qualified customer advocacy groups, as well as solar and storage companies. The Joint IOUs also researched NEM reform in other states to inform our thinking.[6/]

While each IOU has different starting point rates and structures resulting in different levels of NEM adoption, the Joint IOUs have worked together to harmonize differences in assumptions and calculation details in order to provide the Commission, customers and the overall marketplace with a standardized tariff structure.

The Joint IOUs are thus pleased to present a proposed Distributed Generation Successor Tariff (DG-ST) and transitional discount for income-qualified customers (NEM Equity Rider).

4/ Verdant Associates, "Net-Energy Metering 2.0 Lookback Study," Submitted to the California Public Utilities Commission Energy Division, January 21, 2021, pp. 32-33. This study is referred to herein as the "Lookback Study."

5/ Energy + Environmental Economics, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327," Submitted to the California Public Utilities Commission, January 28, 2021, p. 25. This study is referred to herein as the "E3 White Paper."

6/ The Joint IOUs met jointly with solar and storage parties and other stakeholders in fall 2020 to explore potential compromise positions.

Our proposal addresses the drawbacks with the existing NEM program and lays the groundwork for *a modern and equitable distributed generation program*.

Specifically, our proposal:

1. **Eliminates subsidies for new distributed generation customers that do not need them.** Proposes a Net Billing core tariff that sets export compensation based on CPUC-based avoided costs and recovers transmission, distribution, and public purpose costs through new charges. The Joint IOUs also support a financially equivalent dual-meter tariff option called Value of Distributed Energy that eliminates the cost shift while supporting more modern uses of the grid, such as demand response participation.

2. **Encourages distributed solar adoption among traditionally under-represented communities by providing transitional subsidies for income-qualified customers**. Includes discounted fixed charges for income-qualified customers resulting in more favorable value propositions for these customers. This subsidy would be available for qualified customers who receive permission to operate within the first three years from the date the new NEM program begins, and those customers would then receive the subsidy for 10 years. The Joint IOUs anticipate a 40% increase in income-qualified adoption by the end of 2025 due to generous income-qualified distributed generation programs.

3. **Provides better incentives for storage technologies for participating customers**. Provides more accurate price signals reflecting the increased value of energy during peak periods and prepares distributed generation resources to be better aligned with grid needs. Storage also provides resiliency benefits for individual participating customers.

The Joint IOU proposal, as a package, reduces the inequitable cost shift and ensures that any remaining subsidies for new distributed generation customers go to those most in need. The proposal also reverses an existing "low-income penalty" by ensuring that income-qualified customers receive the same compensation for exports and face a better value proposition for installing distributed generation than non-qualifying customers.

II. DISTRIBUTED GENERATION SUCCESSOR TARIFF PROPOSAL

A. Overall Design

1. Satisfaction of Statutory Criteria and Guiding Principles

The Joint IOU proposal meets the requirements of AB 327 that the new tariff:

1. Ensures that customer-sited behind-the-meter renewable generation continues to grow sustainably;

2. Eliminates the cost shift created when NEM customers are compensated more than the generation is worth, while continuing to promote the adoption of solar systems; and

3. Offers alternatives for residential customers in disadvantaged communities.

The proposal is also consistent with the Commission's Guiding Principles adopted in D.20-02-007.

Table 1 lists these requirements[7/] and Guiding Principles and summarizes how the Joint IOU proposal meets each.

Table 1

Summary of how the Joint IOU Proposal Meets Legislative Requirements and Guiding Principles

	Legislative Requirement or Guiding Principle	Joint IOU Proposal	Location in Document
AB 327 -- Requirements of Public Utilities Code Section 2827.1			
1	Sustainable Growth of Behind-the-Meter Renewables - 2827.1(b)(1)	• Provides a reasonable value proposition for customers. • Customer economics are consistent with other utilities that have reformed NEM, many of which did so at much lower levels of penetration.	Section II.B Section III Section IV
2	Elimination of Cost Shift - 2827.1(b)(3), 2827.1(b)(4)	• Export values are based on the CPUC's calculation of avoided cost. • Customers pay their share of customer costs, grid costs, and public purpose programs through a combination of a Customer Charge and a Grid Benefits Charge.	Section II.B
3	Include Alternatives Designed for Growth in Disadvantaged Communities - 2827.1(b)(1)	• Income-qualified customers are eligible for a discount on the Grid Benefits Charge to improve customer economics. • On average, the value proposition for income-qualified customers installing rooftop solar under the Joint IOU proposal is better than for higher-income customers.	Section V
Guiding Principles of D.20-02-007[8]			
(a)	Comply with Public Utilities Code Section 2827.1	• See above	Section II.A

7/ AB 327 also includes provisions related to sizing, transition periods for existing NEM customers, and terms of service and billing rules. The Joint IOUs do not propose any changes to the NEM tariff that would affect these provisions.

8/ The Guiding Principles, as discussed herein, follow the lettering provided in D.20-02-007, Ordering Paragraph 1.

	Legislative Requirement or Guiding Principle	Joint IOU Proposal	Location in Document
(b)	Ensure equity among customers	• Mitigates the cost shift as described above to limit the impact of the NEM program on non-participants, while expanding offerings to income-qualified customers.	Section II.B Section V
(c)	Enhance consumer protection measures for customer-generators providing net energy metering services	• Eliminates surprising and challenging annual true-ups. • Provides greater transparency on export compensation and responsibility for paying for grid maintenance. • Value of Delivered Energy option provides more transparency for customers on gross consumption and rooftop solar generation.	Section VI
(d)	Fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1	• The proposed tariff is designed in a manner that anticipates the participation of other eligible technologies (e.g., compensation during evening hours based on avoided costs).	Section II.B

	Legislative Requirement or Guiding Principle	Joint IOU Proposal	Location in Document
(e)	Coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill (SB) 100 (2018, DeLeon), the Integrated Resource Planning (IRP) process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18	• SB 100: Promotes decarbonization at least cost by proposing compensation for behind-the-meter renewables based on utility avoided costs. Also promotes stable retail rates, a goal of SB 100. • IRP: Overall tariff design is informed by avoided costs, which are an output of the IRP. • Title 24: Provides 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: 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.	Section II.B.9
(f)	Transparent and understandable to all customers and uniform, to the extent possible, across all utilities	• The DG-ST structure is uniform across utilities to the extent possible. Some details may vary slightly due to differences in rate levels, rate design practices, and underlying avoided costs. • The proposal is more transparent than the existing NEM tariff because it replaces the NEM subsidy that is currently embedded in rates with a clear value for the energy produced. • The additional optional Value of Distributed Energy tariff compensation structure provides a simpler and transparent structure for customers who choose that option.	Section II.B, Section VI

	Legislative Requirement or Guiding Principle	Joint IOU Proposal	Location in Document
(g)	Maximize the value of customer-sited renewable generation to all customers and to the electrical system	• The DG-ST proposed structure will promote solar-paired storage systems by providing higher compensation for energy produced at higher value times of day. Compared to today's compensation structure, this will provide reliability and environmental benefits to all customers. • The Joint IOUs additionally propose that all new solar-paired storage systems be configured with secure, uniform communications capabilities that enable resource aggregation.	Section II.B, Section III
(h)	Consider competitive neutrality amongst Load Serving Entities	• The successor tariff is designed to achieve neutrality amongst load serving entities by defining which credits and charges are set by the load serving entity and which are set by the distribution utility.	Section II.B.4

2. Comparison to E3 White Paper Options

The CPUC requested Energy and Environmental Economics (E3) to write a white paper on potential NEM reform tariffs. The E3 White Paper contained three major elements:

1. Decoupling compensation for export energy from the retail rate,
2. Potential rate design changes for customer-generators so that bill reductions align more closely with avoided costs, and
3. A Market Transition Credit (MTC) to provide additional financial incentives to solar installers.[9]

The E3 White Paper provides different uses for the MTC, including creating a glide path for the industry and/or providing incentives to specific customer groups (e.g., income-qualified customers).[10]

The Joint IOU proposal is consistent with the alternatives presented in the E3 White Paper in several ways:

9/ E3 White Paper, p. 16.

10/ E3 White Paper, pp. 3-6.

1. **Decoupling Compensation from Retail Rate** – The Joint IOUs propose to set export compensation based on CPUC-calculated avoided costs. Additionally, for cost shifts due to customer-generator onsite usage (e.g., avoided transmission, distribution and public policy costs), the Joint IOUs propose a suite of fixed and usage charges.

2. **Rate Design** – The Joint IOUs propose a default, cost-based, time-of-use (TOU) rate for all customer-generators. Of the rates put forward by E3, the Joint IOU proposal is most similar to the Multi-Part Grid rate, which features a customer charge and a grid access fee.[11/]

3. **Market Transition Credit** - The Joint IOUs propose a discount for income-qualified customers that install NEM during the first three years of the new DG-ST tariff. This is similar to the MTC targeted at specific customer groups discussed in the E3 White Paper. The Joint IOUs do not support an additional transition credit to all customers given the size of the existing cost shift and the fact that it will have been nearly a decade since the passage of AB 327 by the time the new tariff is implemented.

B. Components and Structure

1. Overview

The Joint IOU proposal contains several features that are designed to reduce the impact of the NEM program on non-participating customers. The features are intended to work together to reduce the cost shift while fairly compensating customers that invest in distributed generation.

First, new DG-ST customers would be placed on a more 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 Grid Benefits Charge based on their rooftop solar system's installed capacity (kW-DC). The Grid Benefits Charge will be designed to recover costs that would otherwise be shifted due to solar customers' onsite consumption.

These changes will rationalize the estimated payback periods for participating customers. Currently, as shown in Table 2, the payback periods[12/] for customers installing rooftop solar under the existing NEM program are quite short.

11/ E3 White Paper, p. 23.

12/ 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.

Table 2

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

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

Under the Joint IOU proposal, participating customers could expect the following, more reasonable payback periods:

Table 3

Joint IOU Proposal -- Illustrative Estimated Payback Periods of Participating DG-ST Customers

Utility	Estimated Payback Period (Standalone Solar)	Estimated Payback Period (Solar + Storage)
PG&E	15 years	13 years
SDG&E	11 years	10 years
SCE	15 years	11 years

2. Applicability and Timing

Generally, the applicability for the Joint IOUs proposed successor tariff will remain consistent with that of the current NEM 2.0 tariff. Eligible customers and eligible renewable electrical generation facilities for the successor tariff are still defined by California Public Utilities Code Section 2827.1. Customer-sited facilities larger than one megawatt in size will continue to be eligible for the successor tariff, so long as the customer pays all Rule 21 interconnection study and distribution system upgrade fees for the facility. Additionally, a consolidated Virtual Net Metering (VNEM) tariff and net metering aggregation (NEMA) sub-schedule of the NEM tariff will be maintained and updated to be consistent with the successor tariff.

Given the significance of the existing NEM program cost shifts, the need to limit additional customers from locking into these outdated compensation levels is paramount. The Joint IOUs propose that upon issuance of a final decision in this proceeding, all new, eligible customer-generators who interconnect, as well as existing customers who upgrade their distributed generation systems, shall be obligated to take service on the new successor tariff. The term of the new successor tariff will remain open-ended, and its rates and rate design will be subject to periodic changes.

3. Base Time-of-Use Rates

The Joint IOUs propose that new distributed generation customers take service on a default cost-based rate. The default rates will vary by utility due to differences in costs and rate design practices but will have common elements such as non-tiered TOU rates and customer charges. This structure will improve equity in cost recovery and encourage consumption during non-peak hours and exports during peak hours. Providing incentives to shift usage to non-peak hours or exports during peak hours will provide the greatest benefit to the grid and support the state's climate goals. Income-qualified customers on CARE and Family Electric Rate Assistance (FERA) programs would continue to benefit from applicable rate discounts on these programs and would receive the same compensation for export energy as non-qualifying customers.

For the new DG-ST to be successful in reducing the existing inequities and for the state to pursue its clean energy goals in a sustainable manner, it is critical for DG-ST 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 decarbonization. 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."[13/] 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.

SCE proposes to use its existing TOU-D-PRIME (PRIME) rate, which is a non-tiered TOU rate with a customer charge that was approved in its 2018 General Rate Case (GRC) Phase 2.[14/] PG&E and SDG&E propose new rates in this proceeding (E-DER and TOU-DER, respectively) that will be the default rate for successor tariff customers. In addition, PG&E and SDG&E would allow customers to select other available, non-tiered time-of-use rates, such as rates to support transportation and building electrification (e.g., in PG&E's case, EV2 or the currently proposed E-ELEC rate).[15/]

The proposed default rate customer charges for each IOU are summarized in Table 4 below and described more fully in the subsections that follow.

Table 4

Illustrative Proposed Residential Default Rate Customer Charges

Utility	Proposed Default Rate	Tariff Currently Effective?	Customer Charge (/month)

13/ E3 White Paper, p. 33.

14/ D.18-11-027.

15/ Calculation of the Grid Benefits Charge described later in this section may vary for other optional rates depending on the structure of the underlying rate. For example, if the underlying rate does not have a customer charge or has a lower customer charge, the Grid Benefits Charge would be higher.

PG&E	E-DER	No	$ 20.66
SDG&E	TOU-DER	No	$ 24.10
SCE	TOU-D-PRIME	Yes	$ 12.02

a. PG&E's Rate Proposal

Like SDG&E (below), PG&E proposes a new non-tiered TOU rate in this proceeding that will serve as the default rate for residential DG-ST 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 DG-ST 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).[16/] Fully scaled by "equal percentage of marginal costs" (EPMC), this would justify a $31.05/month customer charge for DG-ST customers were they a separate customer class.

PG&E would also be open to residential DG-ST 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 may require different associated Grid Benefits Charge levels to ensure fair distribution cost contribution from DG-ST customers. Within PG&E's Phase 2, there are also pending proposals to provide residential PG&E customers with "real time pricing" based rates. In the event that such a rate is approved, it would be reasonable to allow DG-ST customers with battery storage to take service on such a rate. However, this would also require that real time pricing rate to either have similar rate design as E-DER for non-real time components or have the corresponding Grid Benefits Charge.

16/ A.19-11-019.

Table 5 below shows PG&E's proposed illustrative default rate structure.

Table 5

PG&E Proposed Illustrative Residential Default Rate (E-DER)

Charge	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
TOU Differentials		
Summer On: Off-Peak		1.8 : 1
Winter On: Super Off-Peak		1.15 : 1

b. SDG&E's Rate Proposal

Like PG&E, SDG&E proposes a new, more cost-based, non-tiered TOU rate as the default rate for residential DG-ST customers. This rate would be available with no eligibility restrictions on an opt-in basis to other, non-DG-ST customers. Current residential rate design is misaligned with cost causation principles; residential rates recover nearly all costs in volumetric (kWh) rates, regardless if those costs are fixed. A new, more cost-based rate will ensure that future DG-ST customers receive more appropriate price signals and will allow for a corresponding lower Grid Benefits Charge. 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 customer charge and non-tiered, cost-based volumetric TOU differentials, using SDG&E's current effective standard TOU periods. Cost-based TOU differentials will provide DG-ST customers with appropriate price signals during on-peak periods and encourage adoption of paired storage devices (batteries).

SDG&E's proposed customer charge recovers fully scaled distribution customer costs.[17/] The fixed charge in the DG-ST would not be incremental; recovery of costs through this fixed customer charge will result in a compensating reduction in the current rate structure's artificially inflated volumetric distribution rates. A cost-based fixed charge will help move toward a more equitable system and balanced rate structure.

17/ Public Utilities Code § 2827.1(c)(7) specifically allows for the CPUC to approve fixed charges for solar customers that are different from non-solar residential customers.

Table 6 below shows SDG&E's proposed illustrative residential default rate structure.

Table 6

SDG&E Proposed Illustrative Residential DG-ST Default Rate

Charge	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
TOU Differentials		
Summer On: Super Off-Peak		2.5 : 1
Winter On: Super Off-Peak		1.1 : 1

While SDG&E is proposing a default rate for future DG-ST customers, SDG&E reserves the right to open other more cost-based rate schedules to these customers in the future. However, SDG&E's current residential rate schedules with no eligibility restrictions would not be appropriate for these DG-ST customers to take service on, as they do not have a customer charge. SDG&E proposes to restrict DG-ST customers to the default proposed rate or Value of Distributed Energy (VODE) tariff described in Section II.C, until other, more cost-based rates are approved by the CPUC.[18/]

c. SCE's Rate Proposal

SCE's current PRIME rate is a non-tiered TOU rate with a $12 customer charge to recover a portion of the customer-related costs, which was approved in its 2018 GRC Phase 2.[19/] SCE proposes to default new DG-ST customer to PRIME. The use of PRIME as the default DG-ST rate will encourage the adoption of paired storage by offering steeper price differentials between the highest- and lowest-cost periods. Additionally, the inclusion of a customer charge helps reduce the level of Grid Benefits Charge necessary to achieve a given reduction in the cost shift. In the future, DG-ST customers may select alternative residential TOU rate options, if other more cost-based TOU rate schedules with fixed charges become available.

In SCE's open 2021 GRC Phase 2 case (A.20-10-012), SCE discusses how PRIME was originally designed for residential households with an electric or plug-in hybrid vehicle, behind-

18/ For example, SDG&E was ordered in D.20-03-003 to file an application for an optional residential untiered TOU rate with a fixed charge for customers with certain electrification technology. SDG&E may propose to allow DG-ST customers to also take service on this rate.

19/ D.18-11-027.

the-meter battery, or building electrification technologies by using a basic fixed charge to reduce the volumetric kWh price levels closer to marginal cost.

In this open 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 March 2021 are shown in Table 7 below.

Table 7

SCE's PRIME Rate – Non-CARE

Charge	**Unit**	**Total Rate**
Customer Charge	$/month	$12.02
Energy Charges:		
Summer:		
On-Peak	$/kWh	0.44
Mid-Peak	$/kWh	0.33
Off-Peak	$/kWh	0.17
Winter:		
On-Peak	$/kWh	0.41
Off-Peak	$/kWh	0.16
Super Off-Peak	$/kWh	0.16
TOU Differentials		
Summer On: Super Off-Peak		2.6 : 1
Winter On: Super Off-Peak		2.6 : 1

Under PRIME, 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 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.

4. Export Compensation Rate

a. Summary

The Joint IOUs propose that exports from DG-ST 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 (ECRs) are shown for each utility in Tables 8-10. The approach of compensating exports according to their actual value is common among jurisdictions that have replaced net metering, including several California Municipal Utilities and two small multi-jurisdictional utilities subject to CPUC regulation.

Table 8

Seasonal TOE Values - PG&E

Summer	$/kWh	Winter	$/kWh
On Peak	0.13	On Peak	0.06
Part Peak	0.08	Part Peak	0.05
Off Peak	0.06	Off Peak	0.05

Table 9

Seasonal TOE Values - SDG&E

Summer	$/kWh	Winter	$/kWh
On	0.14	On	0.06
Off	0.07	Off	0.05
Super-Off	0.06	Super-Off	0.05

Table 10

Seasonal TOE Values - SCE

Summer	$/kWh	Winter	$/kWh
On	0.15	Mid	0.07
Mid	0.15	Off	0.06
Off	0.07	Super-Off	0.05

The remainder of this section describes the methodology and rationale for how these ECRs are determined.

b. Use of the Avoided Cost Calculator

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 Joint IOUs propose to leverage the ACC's analysis of the value of distributed energy resources (DERs) to inform the level of the ECR, subject to other considerations in order to avoid unintended consequences.

The ACC produces a forecast of values for each hour of the year. To aggregate these 8,760 hourly values into ECRs, the Joint IOUs propose weighting the ACC avoided costs by metered customers' exports. This ensures that the DG-ST customers will receive utility avoided costs for their exports.

This approach also 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 can change over time as the mix of technologies participating in the successor tariff evolves. For example, as solar-paired storage proliferates in IOU 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.

c. Other Adjustments

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 time period. This cap is unlikely to impact residential 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. [20/] Ideally, export rates should align as much as possible with utility marginal costs. In the future, the Joint IOUs 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 have relatively short duration support capabilities. 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" 4-9 p.m. peak period.

d. Bundled vs. Unbundled Customer Treatment

Per Guiding Principle (h),[21] the successor 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.

The 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 adder, and methane leakage. Note that while the greenhouse gas 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.

e. Update Cadence

The ECR would be updated annually via a Tier 1 advice letter following the adoption of the annual ACC update. The update would use the ACC's forecast of year-ahead values to inform the export compensation. This frequency would ensure the ECR remains consistent with underlying costs and CPUC policies. The illustrative ECRs in Tables 8-10, above, are from the 2020 version of the ACC, forecasting year 2021 avoided costs, levelized one year. By the time the DG-ST is implemented, the 2021 version of the ACC will be available, as well as perhaps the 2022 version, so the above rates should be taken as illustrative.

The Joint IOUs recognize that a fixed ECR based on a long term, levelized forecast from the ACC would be preferable to the solar industry. Such a structure represents a significant shift

---

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

21/ D.20-02-007, Ordering Paragraph 1.

in risk from generators to non-participating customers. In the current version of the ACC, values tend to increase over time. If the value reflected in the outer years of the 2020 adopted ACC is borne out by reality, customer-generators should be paid at those higher rates. 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 DG-ST customer-generators are compensated fairly and that non-participating customers do not overpay for their generation.

5. Netting Interval / True Up

Today, NEM customers are credited the retail rate for each kWh they export to the grid. When they are net exporters, customers are able to carry forward ("bank") credits to offset any future grid consumption nettable charges 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 (NSC) rate as a cash payment.

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 both costs. 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. Additionally, many NEM customers today 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 this proceeding, the Joint IOUs propose the following for residential and non-residential customer groups:

- DG-ST customers will pay the retail rate for all delivered energy;
- For each billing cycle (usually monthly), a customer's exported energy will be priced at the applicable ECR depending on TOU period, up to the amount that is delivered to the customer in that same TOU period;
- Any remaining exported energy not subject to the export compensation rates will be paid at the monthly NSC rate, like how current NEM customers are compensated at the end of their relevant period;
- No energy credits will be banked and carried forward from prior billing cycles.

The Joint IOUs propose 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 in Section II.B.4. above.

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. Under the Joint IOU proposal, customers will be credited for every kWh exported to the grid, up to the amount of kWh they import from the grid. This feature would encourage storage, as customers would have an incentive to consume their generation onsite.

Because the IOUs are proposing export compensation that is TOE differentiated, customers will only be allowed to offset within each TOU period. 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 will provide better price signals than allowing customers to use over-generation during the day when wholesale market prices are low and the IOUs are forced to curtail utility-scale solar generation, to offset their consumption in the evening hours.

Under the Joint IOU proposal, customers cannot carry over export credits from one month to the next month. Currently, at a customer's annual true-up, the IOU adds up the net of each month's kWh. If the customer has net negative kWh (is a net exporter), then those negative kWh are compensated at the NSC rate. This means that significant generation and exports in the spring months can provide customers with bill credits that can be used in summer when customers are pulling a greater share of their energy from the grid and costs are higher.

The current 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 more accurately track their system's production and impact on bills. As described further in Section VI.A., 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.

An example of export compensation netting is presented below in Table 11.

Table 11

Export Compensation Netting Proposal Example

TOU/TOE Period[22/]	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 will be compensated at wholesale rates.

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.

22/ Illustrative based on SDG&E's current effective standard TOU periods.

6. Grid Benefits Charge

Customers without solar currently pay for costs of the grid, generation, policy mandates and customer services through volumetric rates. Under 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 this type of cost avoidance, the Joint IOUs propose to assess a $/kW-month Grid Benefits Charge based on a customer's installed solar system size. This charge will vary by utility. 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 DG-ST were only to adopt a change in export compensation, California would see a significant cost shift in the future from solar-paired storage customers.

A Grid Benefits Charge will help ensure that California is adopting a tariff that ensures non-participant equity. 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-paired storage customers do not export a significant amount of their generation. If a solar-paired 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%.

Each utility's Grid Benefits Charge will be based on current effective rates, and the observed estimated average export percentage of that customer class. If residential customers export, on average, 60% of their generation as is the case in SDG&E's service territory, then the Grid Benefits Charge should recover the costs that are avoided by consuming 40% of self-generation onsite. The Joint IOUs believe that the DG-ST 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.

The Joint IOUs recognize that setting the Grid Benefits Charge 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 Grid Benefits Charge 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 Grid Benefits Charge for the solar-paired storage customers would be too low to achieve non-participant indifference. Thus, the Joint IOUs 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 Joint IOUs propose that the issue of providing a single Grid Benefits Charge for both standalone solar and solar-paired storage be revisited in either the Joint IOUs' respective GRC Phase 2 or Rate Design Window after the implementation of the DG-ST. 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.

a. Cost Components

The Grid Benefits Charge will recover remaining distribution costs, transmission,[23] and bundled rate components, minus relevant avoided costs as established by the ACC tool. The Joint IOUs propose that non-bypassable charges (NBCs) be included in the Grid Benefits Charge. The Joint IOUs acknowledge that certain NBCs are required to be collected "on the basis of usage,"[24] but believe that estimated onsite consumption will satisfy this requirement, similar to how standby customers are currently assessed NBCs based on estimated usage.

An illustrative Grid Benefits Charge for each IOU is displayed below in Table 12.

Table 12

Illustrative Proposed Residential Grid Benefits Charge

IOU	Monthly Charge/kW
PG&E	$ 10.93
SDG&E	$ 11.09
SCE	$ 7.39

Using these illustrative charges, if a customer installs a 5 kW-DC solar system, in PG&E's service territory that customer will pay: 5 kW x $10.93/month = $54.65/month Grid Benefits Charge. If a customer installs a 5 kW-DC solar system paired with battery storage, that customer would pay the same charge.

b. Update Timing

In order to provide more certainty and enhance customer understanding, the Grid Benefits Charge should be updated at least once per year to adjust for currently effective rates, with each IOU's respective annual consolidated filing, which typically occurs on January 1.[25] 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 with 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. However, changes to assumed consumption and export behavior will be considered through GRC Phase 2 or Rate Design Window proceedings.

23/ Transmission rates are FERC jurisdictional. The IOUs will propose this rate design in their respective FERC proceedings pending its adoption by the CPUC.

24/ Public Utilities Code § 381(a).

25/ The Grid Benefits Charge 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 Grid Benefits Charge 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 Grid Benefits Charge will experience two separate adjustments.

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

The design of the Joint IOUs' Grid Benefits Charges are based on the assumption that the IOUs' proposed cost-based rates are adopted as the default rates for DG-ST customers. As discussed in Section II.B.3., a more cost-based rate with a fixed charge allows for design of a lower grid equity charge. However, if the Commission does not adopt the Joint IOUs' proposal for a more cost-based default rate, the required Grid Benefits Charge to achieve non-participant indifference should increase to compensate for the higher volumetric rates that result from not having a fixed charge as part of the DG-ST rate design. Table 13 shows illustrative charges for each IOU based on the current residential default TOU rate.

Table 13

Illustrative Residential Grid Benefits Charge – No Cost Based Default Rate

IOU	Monthly Charge/kW[26/]	Otherwise Applicable Rate
PG&E	$ 14.51	E-TOU-C
SDG&E	$ 14.50	TOU-DR1
SCE	$ 13.46	TOU-D-4-9pm

7. Non-Residential Considerations

Non-residential base rate structures represent a more cost-effective structure when considering NEM participating customer benefits and the costs of NEM benefits borne by non-participating customers. All three IOUs use multi-part rate designs consisting of fixed charges, demand charges, and time variant energy charges for non-residential service. In some cases, time-variant demand charges are also included to account for generation capacity cost recovery. Multi-part rate design reduces the avoidance of fixed grid infrastructure and grid connection costs through NEM participation. As a result, successor 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. Non-residential customers will 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 Lookback Study. 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.[27] The report also demonstrates participant benefits can be retained at reasonable levels (i.e., Participant Cost Test (PCT) score above 1.0) as the impact to non-participants is mitigated. Table 5-8 in the Lookback

26/ Illustrative charge does not account for baseline adjustment rate component.

27/ Lookback Study, pp. 90-93.

Study[28/] (reproduced below as Figure 1) illustrates the range of PCT and Ratepayer Impact Measure (RIM) test values achieved between SCE rates that predominately recovered distribution grid costs through demand charges (SCE rate Option D) and one with higher energy charge and less recovery through demand charges (SCE rate Option E).

Figure 1

CPUC NEM 2.0 Lookback Study Table 5-8

TABLE 5-8: SCE BENEFIT-COST RATIOS BY RATE AGGREGATES

	Aggregate Weighted Benefit-Cost Ratios			
	PCT	TRC	RIM	PA
TOU-PA3-E	1.16	1.44	0.93	674
TOU-8-D	1.12	1.33	0.91	898
TOU-GS1-D	1.10	1.16	0.81	30
TOU-PA2-E	1.31	1.46	0.78	271
TOU-GS2-D	1.23	1.32	0.77	101
TOU-GS3-D	1.29	1.40	0.77	350
TOU-PA2-D	1.28	1.36	0.75	134
TOU-8-E	1.31	1.40	0.75	825
TOU-PA3-D	1.33	1.40	0.72	323
TOU-EV-NR	1.35	1.39	0.71	106
TOU-GS3-E	1.37	1.38	0.69	271
TOU-GS2-E	1.39	1.37	0.67	100
TOU-GS1-E	1.32	1.12	0.60	11
Residential	1.62	0.80	0.43	8

The relative effectiveness of cost recovery with non-residential base rate designs leads the Joint IOUs to maintain their current non-residential base rate structures as an element of the successor tariff. The balance of the Joint IOU non-residential successor tariff proposal consists of the following four elements:

1. A time-variant export compensation rate;
2. A Grid Benefits Charge to supplement recovery of fixed and infrastructure costs;
3. A monthly true-up period in place of the current annual true-up period; and
4. Non-bypassable cost recovery.

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 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 IOUs 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

28/ Lookback Study, p. 91.

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. Applying the Grid Benefits Charge and existing demand charge in this way will avoid the recovery of the same costs through two different rate components.

The Joint IOUs propose to adopt a monthly netting period to non-residential segments, similar to the residential segment as described above.

Tables 13-15 below show examples of the Grid Benefits Charge for existing non-residential rates.

Table 13

PG&E Non-Residential Grid Benefits Charges by Rate Schedule

Rate	Grid Benefits Charge (/kW)
B1	$16.34
B6	$15.57
B10S	$9.27
B10P	$8.36
B10T	$4.52
B19S	$3.81
B19P	$3.02
B19T	$3.19
B20S	$3.38
B20P	$3.02
B20T	$2.10
AG-A1	$13.57
AG-A2	$8.95
AG-B	$12.75
AG-C	$8.13

Table 14

SDG&E Non-Residential Grid Benefits Charges by Rate Schedule

Rate	Grid Benefits Charge (/kW)
TOU-A	$ 17.19
TOU-M	$ 11.58
AL-TOU	$ 7.67
DG-R	$ 13.60
PA-T-1	$ 2.12
TOU-PA	$ 18.58

Table 15

SCE Non-Residential Grid Benefits Charges by Rate Schedule

Rate	Grid Benefits Charge (/kW)
GS-1	$ 11.13
GS-2	$ 5.35
GS-3	$ 4.89
PA-2	$ 3.17
PA-3	$ 1.10
TOU-8 Primary	$ 3.99
TOU-8 Secondary	$ 4.32
TOU-8 Subtrans	$ 0.86

8. Virtual Net Metering / Aggregation

a. Background

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

- Multifamily Affordable Solar Housing (MASH) Program: The virtual net metering program first developed to serve MASH customer participants, but later expanded to include participants of the New Solar Homes Partnership (NSHP) Program and customers with solar generation receiving incentives through the Low-Income Weatherization Program (LIWP).

- Solar on Multifamily Affordable Housing (SOMAH): The virtual net metering program for 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 designed for agricultural customers but open to any customer meeting the criteria of a single owner with multiple accounts on contiguous and adjacent parcels.

One of these programs was established by the Legislature. That is, NEMA was added to Public Utilities Code Section 2827 by SB 594 in 2012.[29/] The other tariffs were established by the CPUC.[30/]

VNEM tariffs are fundamentally different than a standard NEM tariff in that the VNEM generation may be 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. Obviously exporting such a large volume of energy can increase the interconnection costs – partially because grid upgrades to accept the exported power are sometimes necessary. Some of these additional interconnection costs are subsidized by non-participants. In addition, billing costs are typically higher for these arrangements.

Unlike simple NEM installations, some of the assumed benefits from NEM, such as avoided distribution costs, simply do not exist for virtual arrangements. The benefitting account customer is billed as if the generation occurred behind-the-meter and directly served their load, when in fact it did not. From the grid's perspective, that customer's usage did not change at all.

b. Joint IOU Proposal for Virtual Crediting Tariffs

The Joint IOU proposal draws a distinction between VNEM tariffs that support income-qualified customers and those that do not. There are policy reasons to continue more generous virtual crediting programs for income-qualified customers. These programs are also consistent with legislative direction to provide access to behind-the-meter solar to residential customers in disadvantaged communities. Further discussion of virtual crediting tariffs for income-qualified customers is contained in Section V.C., below.

There are some modifications to virtual NEM tariffs that should be implemented for all customers to align with the general DG-ST proposal, enhance customer understanding and reduce program costs. The Joint IOUs propose that the virtual crediting tariffs be modified accordingly:

- All exports to the grid from the generating account should be valued at avoided costs at the export compensation rates in the DG-ST proposal. There should be no netting of customer load using an allocation of kWh because the energy generated by the generating facility is not consumed on site for any of the exported electricity.

29/ Two additional VNEM tariffs were included in the scope of the proceeding -- NEM Fuel Cell (NEMFC) and Generation Benefit Credit Transfer program (RESBCT) -- however modifications to these tariffs would require Legislative action. Neither of these tariffs is included in Public Utilities Code Section 2827, thus neither can be amended as a result of the Legislative direction in Section 2827.1. NEMFC is governed by Public Utilities Code Section 2827.10 and RESBCT is governed by Public Utilities Code Section 2830.

30/ NEMV was established by the CPUC in D.11-07-031 based on a staff proposal to expand MASH to non-income-qualified customers.

- For MASH, SOMAH and NEMV, revenues from exported energy should be allocated to benefitting accounts as a dollar credit.
- For NEMA, revenues from exported energy should be allocated to NEMA benefitting accounts as a dollar credit with allocation determined by the customer at the time the arrangement is interconnected and changeable annually. The customer installing the virtual NEM eligible generator should pay all interconnection costs. (Currently virtual NEM customers can avoid paying these costs in certain circumstances.)

The Joint IOUs propose two virtual crediting tariffs: one for income-qualified customers (DG-ST-VSOM) and one for other customers (DG-ST-V). DG-ST-VSOM is described more fully in Section V.C. below. DG-ST-V consists of a generating account with no load, beyond storage that qualifies for NEM Paired Storage (NEMPS) and a group of benefitting accounts located on contiguous and adjacent property under a single owner. The owner of the property must be the owner of the generating account. All interconnection costs are paid by the owner, as are increased billing costs. Exports are valued at the most recently approved ACC and are allocated to the benefitting accounts as a dollar credit. The owner also determines the percentage allocation of credit for all credits to the benefitting accounts, which allocation can be changed once a year upon payment of necessary billing adjustments. There is no true-up.

9. Other Issues: Communications, Security and Alignment with Other Initiatives

a. Ensuring Dispatchability of Devices

The Joint IOUs propose that customers interconnecting under the proposed tariff would require certain communications and cyber security capabilities, for both solar and storage systems. The universal interconnection configuration requirements 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 among IOUs, and equity among customers.[31/]

- *All DER owners should be required to maintain active cyber security monitoring of their systems.*
    - First, the IOUs propose that all DERs interconnecting under this tariff should be required to maintain active cyber security monitoring. Unmanaged and unsecure DERs connected to the grid represent 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 nameplate capacity. 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 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 system failing to operate due to equipment failure or cyber security breach. Consistent with supply-

31/ See Guiding Principles (b), (f) and (g), D.20-02-007, Ordering Paragraph 1.

side resources, distributed generation facilities should be responsible for maintaining their own systems and ensuring that they function properly. Ratepayers should not pay for operational deficiencies of other customers' devices.

- *DERs should be required to ensure compliant, certified communications capabilities between the IOU and the device, including inverter replacements*.

    - 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.

    - The IOUs propose that all DERs taking service on the DG-ST 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 IOUs and would minimize any inconsistencies in statewide requirements. 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.[32/]

    - Any inverters that are replaced, regardless of when original interconnection occurred, should be required to follow all current communications and 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.

- *Information sharing between utility and device should come at no additional cost.*

    - 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 ensures the IOUs 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.

32/ https://standards.ieee.org/standard/2030_5-2018.html

- *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 IOU 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 greenhouse gas reduction and climate goals.

b. Alignment with Existing Rules/Codes/Initiatives[33]

In addition to addressing the cost-shift associated with the existing NEM program, the Joint IOU proposal would improve alignment with other initiatives already in place. It is specifically aligned with Rule 21, Title 24, SB 100, Executive Order B. 55-18, as well as grid modernization needs. Meeting the goals of these initiatives will require accurate and effective price signals, and the efficient allocation of funding that does not lead to unsustainable rate increases.

(1) Rule 21

The existing Rule 21 interconnection requirements provide a starting point for understanding how DERs can be used to the benefit of both participants and non-participants. These include a requirement for communication and control capabilities that could enable aggregation of DERs to provide grid services. This requirement is crucial for a high-DER grid to maintain reliability and resiliency, and for DERs to fully deliver on their potential value. The necessary requirements for these devices are discussed in more detail above.

(2) SB 100

The Joint IOU proposal is consistent with SB 100 in that it promotes decarbonization of the grid at least cost by compensating behind-the-meter renewables based on avoided cost. SB 100 requires that the mechanisms used to procure renewable energy resources promote "stable retail rates for electric service."[34] Elimination of existing NEM subsidies furthers this goal without compromising RPS targets. The Joint IOUs note that behind-the-meter renewable generation does not count toward RPS compliance and the IOUs have met or exceeded current RPS benchmarks set by SB 100. All three IOUs are currently positioned to meet their 33% RPS compliance requirements in 2020.

(3) Title 24

The Joint IOU proposal continues to provide a reasonable value proposition for customers to install rooftop solar. California Energy Commission (CEC) Title 24 effectively mandates rooftop solar where it is cost-effective for participating customers using a 20-year time horizon. The Joint IOU proposal also results in cost-effective rooftop solar for customers. It is

33/ Guiding Principle (e), D.20-02-007, Ordering Paragraph 1.

34/ Public Utilities Code Section 399.11(b)(5).

important to recognize that the effective mandate on solar additions in new construction through California codes and standards already provides significant market security and stability for DER providers, so additional compensation beyond the value of rooftop solar generation to all customers is not necessary.

(4) Integrated Resource Plan (IRP)

The Joint IOUs propose to use CPUC-calculated avoided costs as the basis for designing the core tariff proposal. Major components of the CPUC ACC, including energy, capacity, and greenhouse gas policy adders, are taken from or derived from IRP modeling. Currently, behind-the-meter resource forecasts are used as a "given" in the IRP, meaning that behind-the-meter resources are baked into the demand forecast (as opposed to candidate resources that are selected through the IRP modeling process). To the extent that the forecast of behind-the-meter resources changes as a result of changes to the NEM tariff, those changes will be reflected in future CEC Demand Forecasts and IRP modeling efforts and, subsequently, avoided cost estimates.

(5) Executive Order B-55-18

California's Executive Order on Carbon Neutrality outlines standards for planning and implementing emission reduction programs that lead to statewide carbon neutrality by 2045. In order to reach this goal, the state will need widespread investment in reliable, affordable renewable energy resources. NEM is one of the costliest methods for procuring renewable energy[35/] and, as such, limits the amount that can be purchased with available funds. The concentration of NEM participation in higher-income geographic areas and resulting cost shift to lower-income communities also makes the current program misaligned with Order B-55-18's directive to prioritize the economic health of low-income and disadvantaged communities.

C. Value of Distributed Energy (VODE) Optional Tariff

1. Summary

While the Joint IOUs believe the core tariff proposal described herein meets the Guiding 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 that 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. This structure has been recognized as being simpler and more transparent for participating customers than other behind-the-meter generation compensation mechanisms. The Joint IOUs do not propose that the VODE tariff 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, an IOU 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.

35/ Levelized Cost of Carbon Abatement: An improved cost-assessment methodology for a net-zero emissions world. Columbia SIPA Center on Global Energy Policy, Friedmann et al. (October 2020), p. 31 (finding that rooftop solar is a high cost means of carbon abatement relative to other sources of renewables, based on analysis of Central California solar power).

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 DG-ST and less than 1 MW in size. At this time, the Joint IOUs 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, though the Joint IOUs welcome stakeholder feedback regarding 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.

4. Compensation

Conceptually, the compensation from this tariff should be approximately equal to the estimated average compensation provided via the DG-ST to non-CARE customers. The intent is to offer similar compensation to customers as the core tariff but with greater certainty that they will achieve those savings. The Joint IOUs 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. Locational and 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 \$0.10/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 16 below.

Table 16

Illustrative PG&E VODE Credits and Adders

Time-of-Generation Period		Baseline VODE (ACC)	Retail Indifference Adder	Income-Qualified Adder	Total
Summer	Peak	$0.15	$0.04	$0.05	$0.24
	Part-Peak	$0.08	$0.04	$0.05	$0.17
	Off-Peak	$0.06	$0.04	$0.05	$0.15
Winter	Peak	$0.06	$0.04	$0.05	$0.15
	Part-Peak	$0.05	$0.04	$0.05	$0.14
	Off-Peak	$0.05	$0.04	$0.05	$0.14
PV Profile Weighted Average Compensation		$0.06	$0.04	$0.05	$0.15

6. Future Integration with Advanced Grid Controls

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.

III. STORAGE CONSIDERATIONS

The Joint IOU proposal recognizes the “win-win” impact of pairing storage systems with distributed solar: (i) for participants, storage provides resiliency during grid outages and the ability to reduce usage during higher price periods and (ii) for non-participants, solar-paired storage provides benefits to the grid. Behind-the-meter battery storage systems can provide a diverse range of system services, spanning ultra-short-term timescales (i.e., sub-seconds to seconds) to medium-term timescales (i.e., hours to days). For example, as more renewable generation and solar generation interconnects with the grid, the grid operator curtails more renewable electricity every year. In May 2020, the CAISO curtailed over 320,000 MWhs of electricity to maintain stability on the grid.[36] Today, when behind-the-meter generation peaks during the midday hours, there is no mechanism in place to curtail energy flowing into the grid, as exists for utility-scale power plants. Paired storage systems help to mitigate this issue.

The Joint IOU proposal thus provides incentives to store energy in batteries at home during the high production, low-value, hours of the day (e.g., during high solar production midday) and to consume or export that energy in the evening when the energy is most valuable and more likely to displace fossil generation. This results in a shorter payback period for solar-

36/ California ISO Website, February 2020.

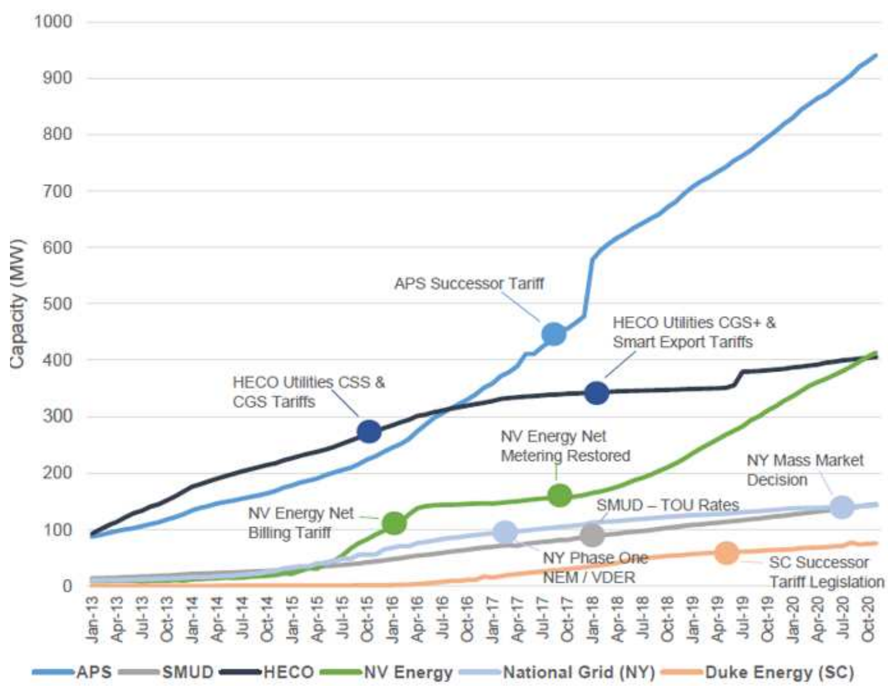
paired storage systems as compared to standalone solar (Table 3). Additionally, the Joint IOUs propose that solar-paired storage systems be configured in a way to enable more modern operation of the resources, when the systems are available. These requirements are discussed in more detail in Section II.B.9.

IV. IMPACTS ON ADOPTION

To evaluate how the Joint IOU proposal may impact rooftop solar adoption, the Joint IOUs have evaluated their proposal against other jurisdictions that have completed NEM reform. The North Carolina Clean Energy Center (NCCEC), which produces a regular "50 States of Solar" industry report, analyzed NEM reforms in other US markets and evaluated the impacts on each marketplace.[37/] As shown in Figure 2 below, reforms (and uncertainty about reforms) can have impacts on markets. However, markets generally are quick to recover, and growth continues.

Figure 2

Residential Solar Net Metered Capacity Over Time

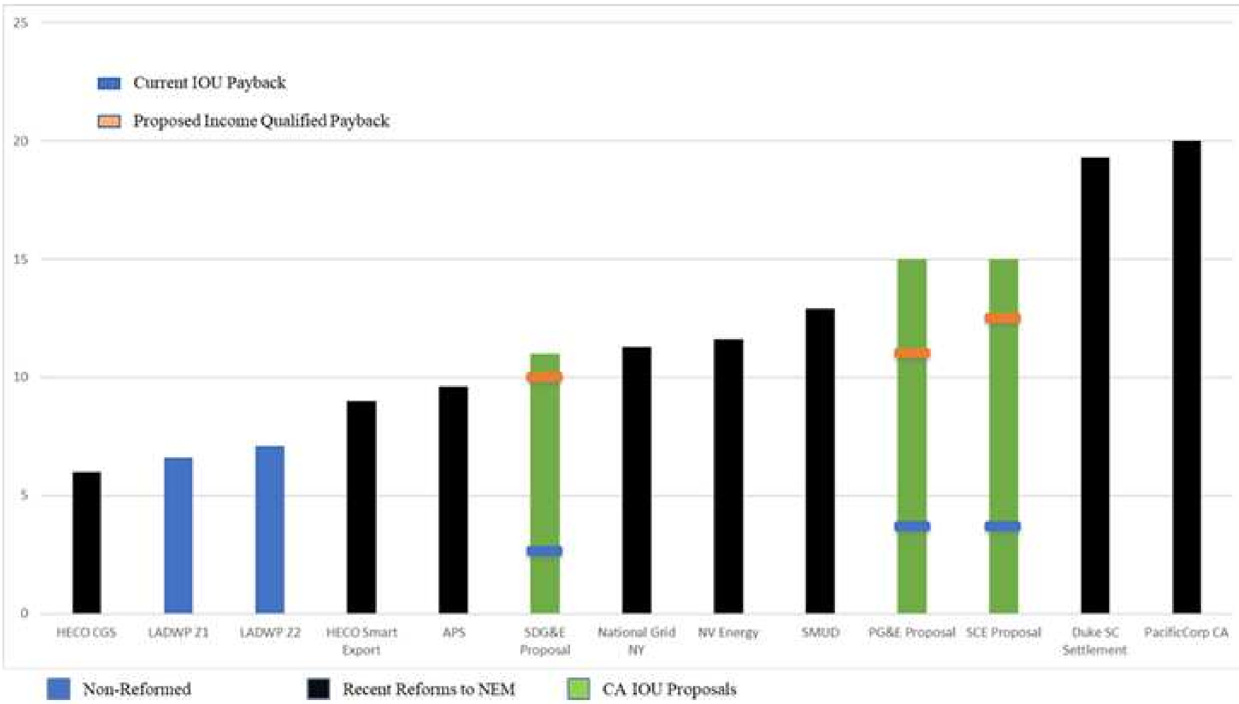


While the relative impact of reform in each area is important, the Joint IOUs have evaluated the estimated system payback times of the Joint IOU proposal against the payback periods of other reformed markets. As demonstrated through Figure 3, the Joint IOU proposal is reasonable and results in payback periods similar to other markets that have undergone reform and subsequently continued to see growth in adoption.

37/ Full report available as Appendix 1.

Figure 3

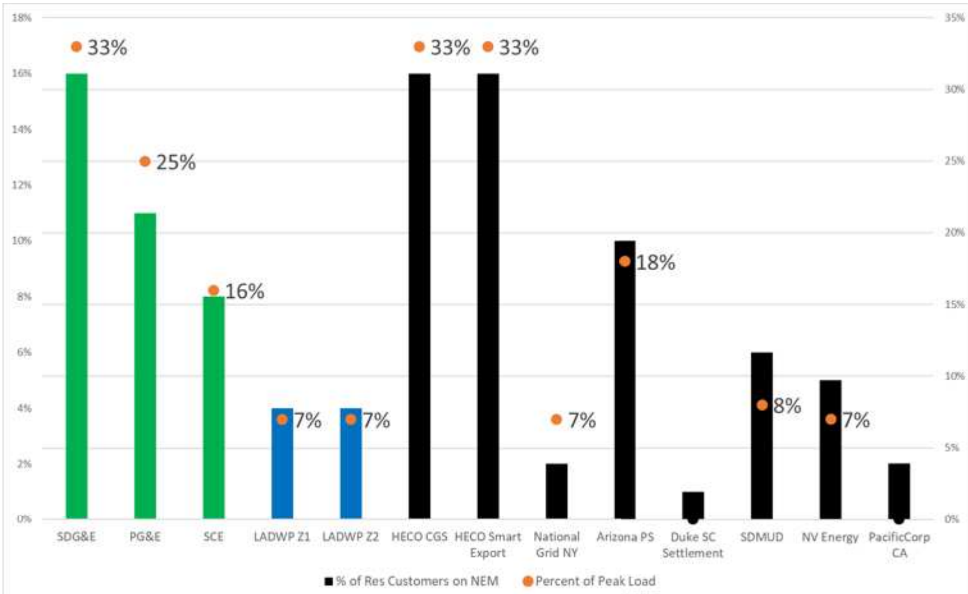
Payback Time of Selected Jurisdictions



In addition, Figure 4 highlights the success in customer adoption of the current NEM program by showing the percent of residential customers who are NEM customers and the percent of peak load that is fulfilled by NEM. The only states with adoption rates comparable to the Joint IOUs are Arizona and Hawaii and both of those states implementing reforms over the past few years.

Figure 4

Percent of Residential Customers on NEM & NEM As a Percent of Peak Load



V. INCOME-QUALIFIED PROPOSAL

The Joint IOU core tariff proposal for the DG-ST will benefit all non-participating customers -- including income-qualified customers -- by eliminating the cost shift for new distributed generation installations. Future distributed generation customers under the Joint IOU proposal will contribute fairly to the cost of maintaining the grid.

Nonetheless, the Joint IOUs propose to improve the economics for income-qualified customers relative to today, where non-CARE customers enjoy shorter paybacks. In addition, significant income-qualified programs will continue to increase adoption, with the Joint IOUs forecasting approximately 70,000 new income-qualified customers[38/] enrolling on distributed generation programs by the end of 2025: a 40% approximate increase in enrollments compared to today's totals.

The Joint IOUs provide income-qualified customers access to solar and distributed generation through several existing programs, some of which are funded through the mid-2020s or through 2030. These include programs that largely or wholly pay for the cost of installing solar and programs that provide solar access to customers who do not own a single-family home.

In addition to the existing solar programs, the Joint IOUs also propose a transitional income-qualified tariff discount to help ensure continued access to solar for lower-income customers who do not take advantage of these programs. This tariff proposal, called the Income-Qualified Rider, focuses on transitional tariff discounts that provide income-qualified customers a better value-proposition than higher-income customers. Table 17 shows the payback period for income-qualified customers using existing programs and the Income-Qualified Rider.

38/ Forecasted installations of 32,000 for PG&E, 6,000 for SDG&E, and 31,000 for SCE.

Table 17

Illustrative Estimated Payback Periods of Income-Qualified Customers with Existing Programs, the Proposed Income-Qualified Rider, and the Joint IOU Core Tariff Proposal (years)

Utility	Payback for Customers Benefitting from Existing Income-Qualified Programs[39]	Proposed Income-Qualified Payback	Proposed Non-Income-Qualified Payback
PG&E	0	11	15
SDG&E	0	10	11
SCE	0	13	15

The existing income-qualified programs (and funding for those programs) are described in subsection A, below, and the Income-Qualified Rider is described in subsection B. The Joint IOUs also propose changes to simplify Virtual Net Metering tariffs for income-qualified customers and those are described in subsection C.

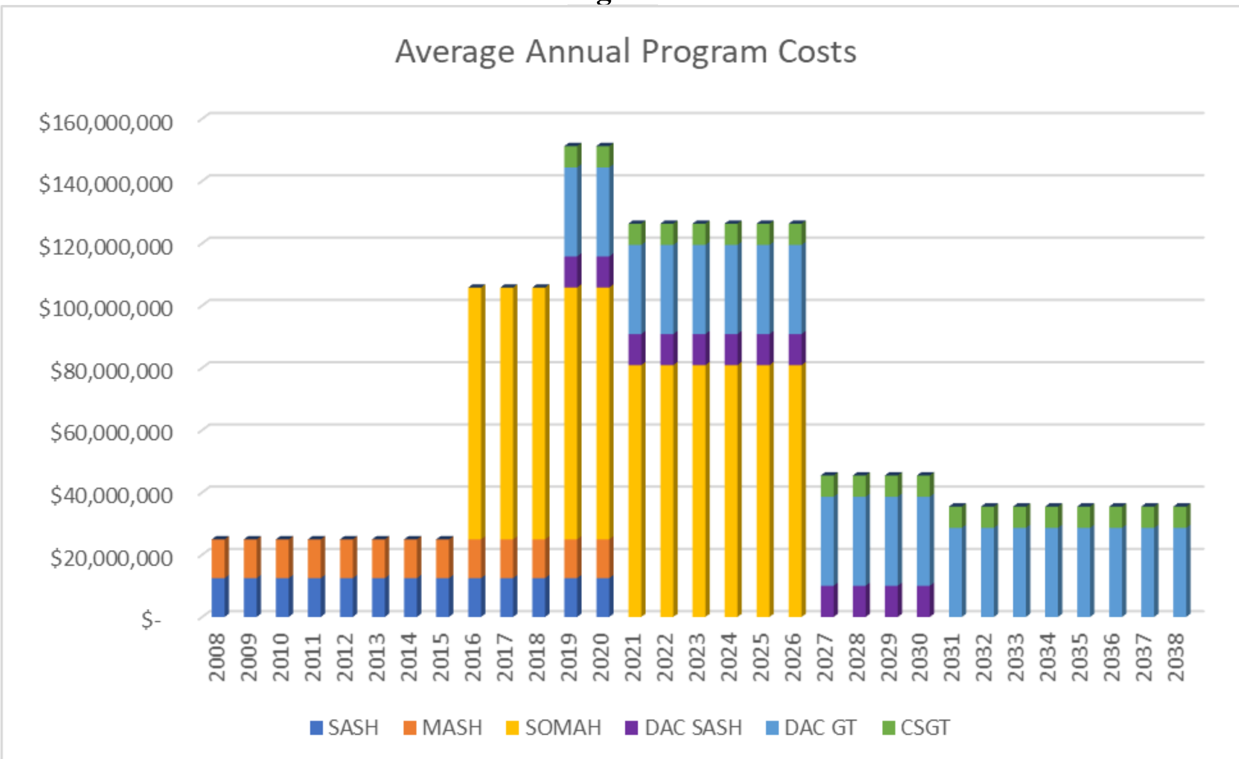
A. Solar Incentive Programs

The Joint IOUs recommend against enhancing funding to the existing roster of allowable incentive program activity until after the next program review cycle in 2024. The program activities that the Joint IOUs considered in arriving at this recommendation included those of SASH, DAC-SASH, MASH, SOMAH, DAC-GT, and CSGT. In examining the existing program set for customers,[40] the Joint IOUs note that funding for these programs is both robust and in transition. Currently, the SASH and MASH programs are in the process of program completion while the DAC-SASH and SOMAH programs, along with DAC-GT and CSGT, are in the early stages of enrollment or installation.

39/ The payback period estimate for benefitting customers includes income-qualified customers 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, guara savings and do not require the installation of any new generating equipment on site. 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.

40/ Existing programs to provide income-qualified customers access to solar generation include SASH, DAC-SASH, MASH, SOMAH, DAC-GT, and CSGT.

Figure 5



Of the $2 billion in program funding illustrated in Table 18 below, nearly $25 million are funded annually through ratepayer collection and nearly $125 million are funded annually through cap-and-trade funds. 49% 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.[41/] Program funding is not included in the Joint IOU cost shift estimate for the NEM program, although it similarly impacts non-participants including non-participating lower-income customers.

The Joint IOUs believe that the funding for these incentive programs is robust and the programs are likely to help address barriers to adoption among underserved populations related to access to necessary capital. If the various incentive programs focused on offering solar access to underserved populations succeed in meeting targets, then upwards of 228,000 such households will gain access to solar, an increase of nearly 50%.

41/ D.17-12-022 (SOMAH) and D.18-06-027 (DAC-GT, CSGT, DAC SASH).

Table 18

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	107,481	VNEM	$849,085,267
DAC SASH	2019-2030	8,649	NEM	$120,000,000
DAC Green Tariff	2019-TBD	67,785	Discount	$572,028,813
CG ST	2019-TBD	13,960	Discount	$136,968,113
Total	--	228,181	--	$2,002,082,193

Gauging these programs' progress against targets will provide a critical input for supporting and understanding adoption within underserved communities. The Joint IOUs estimate that the evaluation period of DAC-SASH and SOMAH post-2024, after DG-ST has been launched in the marketplace, would provide a sufficient learning opportunity 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 Income-Qualified Rider.

B. Transitional Discount for Income-Qualified Customers

The Joint IOUs propose a transitional tariff rider for income-qualified customers called the Income-Qualified Rider (the actual customer-facing name for this will be finalized at a later date) that provides a discount on the Grid Benefits Charge and non-discounted export compensation. The effect of this Rider would be that these customers will pay a nominal amount toward the costs underlying the Grid Benefits Charge. The Rider would be applied in conjunction with programs for which a customer might qualify, including CARE, FERA, and Medical Baseline, and would operate alongside any solar incentive programs that apply such as DAC-SASH.[42/] The Joint IOUs propose the Income-Qualified Rider be adjusted so that the resulting total Grid Benefits Charge be $1.50 per kW for income-qualified customers.

In addition to the reduced Grid Benefits Charge, the Joint IOUs propose that export compensation for all CARE and FERA customers be set at the same rate as all non-CARE and non-FERA customers (e.g., no CARE or FERA discounts are applied to exports).

1. Transition Period and Eligibility

The transitional Income-Qualified Rider would be available to eligible customers who receive permission to operate for the first three years from the date of implementation of the successor tariff. One year prior to the expiration of the Income-Qualified Rider, the Joint IOUs propose that the Commission hold a workshop to examine the success of the tariff and DG-ST

42/ The Joint IOUs propose the Income-Qualified Rider as additional to and distinct from the CARE or FERA discount. The Income-Qualified Rider is a transitional mechanism to comply with AB 327 legislation requiring opportunities for behind-the-meter renewable adoption in disadvantaged communities and, the Joint IOUs believe, should not be considered when calculating average CARE discounts.

programs in providing access to solar for income-qualified customers. The workshop should assess the following:

- Adoption among CARE vs non-CARE customers before and after the latest round of distributed generation 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 to extend the Income-Qualified Rider or propose adjustments. In the event the Commission takes no action by three years after the DG-ST is implemented, the Income-Qualified Rider will expire for all new DG-ST income qualifying customers. In such event, income-qualified customers who take service on the DG-ST with the Income-Qualified Rider and remain eligible for the Rider will continue to receive the lower rate for 10 years.

To maintain integrity of this income-qualified program and ensure subsidies are appropriately allocated, the Joint IOUs propose to use a verification process similar what SCE uses with the DAC Green Tariff. This program features an application requiring customers to complete a questionnaire to ensure they are eligible. If they are eligible for CARE and FERA and are not already on those programs, an application to enroll on those rate programs would be sent to them.

2. Anticipated Cost and Cost Recovery of Income-Qualified Rider

Using the total eligible population eligible for the Income-Qualified Rider, the Joint IOUs estimate a total subsidy of $505 million for all three IOUs over a 13-year period. The Joint IOUs propose that these costs be recovered from all customers through as a Public Purpose Program charge as these are policy costs to support equitable access to solar technologies.[43/]

C. Low Income-Qualified Virtual Net Metering Tariffs

The Joint IOUs propose a single virtual crediting tariff for income-qualified customers for simplicity and customer understandability. The Joint IOUs propose that all MASH and SOMAH customers of new solar installations that receive permission to operate after the implementation date of this tariff take service on a consolidated tariff, called DG-ST-VSOM. As with the non-income-qualified virtual tariff, exports from the generating account are valued at the most recently approved ACC and those dollar credits are allocated to benefitting accounts consistent with current SOMAH allocation methodologies. Export credits will be conveyed to each account as a simple credit, which may offset any part of the bill including NBCs. Customer consumption will continue to be billed according to their current tariff based on meter data, just as they are today, and will receive a monthly credit from the generation exported from the VNEM facility. While current MASH participants must take service on a TOU, SOMAH customers are defaulted to TOU but can opt out. This exception for customers benefitting from the SOMAH program will continue. Finally, both the current MASH and the current SOMAH tariff allow arrangements to have more than one generating account. This would continue for the new DG-ST-VSOM tariff.

43/ The Joint IOUs propose to initially recover these costs through the Public Purpose Programs charge, but each IOU may propose a different recovery mechanism for these charges in the future. SCE has pending proposal for an allocation protocol for transportation electrification and wildfire related costs, a similar approach will be applied to income-qualified program costs.

VI. CONSUMER PROTECTION CONSIDERATIONS

The Joint IOUs 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"[44/] 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.[45/]
- Use standardized inputs and assumptions in projected solar bill savings calculations 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, and standardized inputs and assumptions 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 IOUs to track complaints they receive related to solar providers and report those complaints to the CPUC. Further verification measures of requirements for consumer protection documentation at the time of interconnection are being considered under the latest Assigned Commissioner's Ruling Seeking Comments on Enhanced Auditing Proposal and Solar Transaction Record (January 5, 2021). The Joint IOUs look forward to continuing to provide feedback on the measures outlined above as well as further consumer protection strategies that may be necessary.

The Joint IOU proposed DG-ST tariff will also enhance consumer protection. In designing a new tariff, it is critical that policy makers and stakeholders balance customers' ability to understand NEM pricing and respond to price signals through load management strategies with other rate design principles, such as basing the rate design on cost to serve.

In R.14-07-002 on enhanced consumer protection measures, misunderstanding of both projected and realized bill savings was identified as a key consumer protection issue. In D.18-09-044, the CPUC identified as a key consumer protection issue "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."[46/]

An indication of how challenging current NEM billing is for customers to understand is given by the degree to which solar customers call the IOUs with billing questions. In 2019, for example, PG&E received an average of 27,000 calls per month to its Solar Customer Service Center, 65% of which were related to billing questions.

44/ https://www.cpuc.ca.gov/solarguide/

45/ https://www.cslb.ca.gov/contractors/Solar_Requirements.aspx

46/ D.15-07-001, pp. 16, 28.

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 or sign 3rd party contracts (leases/PPAs);
- 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.

As described below, the Joint IOU proposal will provide greater transparency to customers and vendors, and will be easier to understand, which can reduce confusion about NEM billing.

A. Monthly True-Ups Will Eliminate Surprising and Challenging Annual True-Ups

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. 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 an NBC adjustment for NEM 2 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. The use of this option is about 70% higher among non-CARE customers and 30% higher among CARE customers, which suggests that NEM customers have trouble paying their True-Up bills (Table 19). Feedback from Customer Service Representatives at PG&E's Solar Customer Service Center indicates that the annual true-up is the top "pain point" for NEM customers.

Table 19

Percent of PG&E Service Agreements Using a Payment Arrangement from March 2020 to February 2021 for Customers Taking Service Under NEM, Compared to Non-NEM

	Not on CARE	*On CARE*
NEM	6.9%	23.3%
Non-NEM	4.0%	18.0%
Percent Higher Among NEM Customers	71.9%	29.0%

B. Standardized Export Compensation Will Facilitate Customer Understanding

While customers generally 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. Similarly, customers often wish to verify that projected savings actually materialize after an investment in solar.

A clear standardized compensation rate for solar exports would simplify NEM billing. Under the current NEM2 structure, 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' NBCs, which, in effect, changes the value of solar exports. If a customers' net imports from the grid are high relative to exports, 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 NEM2 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 DG-ST 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 into how load management behavior or technologies such as storage will affect overall bill savings.

C. The Customer and Grid Access Charges clarify that customers still need to pay the IOUs for grid services

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. A Customer Charge and Grid Benefits Charge 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 NEM billing.

D. A VODE Option Would Improve Visibility for Customers

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.[47/] Customers often also want to understand what their bill would have been without solar, which the IOUs do not have information to provide. 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.

VII. LEGACY CUSTOMER CONSIDERATIONS

The existing NEM program has led to cost shifting and created an unfair rate burden for non-participants. This point is well documented in the recently published Lookback Study, which was produced at the direction of the Commission to provide third-party analysis evaluating the current NEM 2.0 program. The Study used tests vetted by the Commission to analyze the cost-effectiveness of NEM 2.0 for participants, ratepayers, program administrators, and as a resource and produces a score to describe if the program is cost effective (>1) or not cost-effective (<1) for each test. The Lookback Study found that, in general, NEM 2.0 systems are not cost-effective from a combined participant and utility perspective, highlighted by a Total Resource Cost test

---

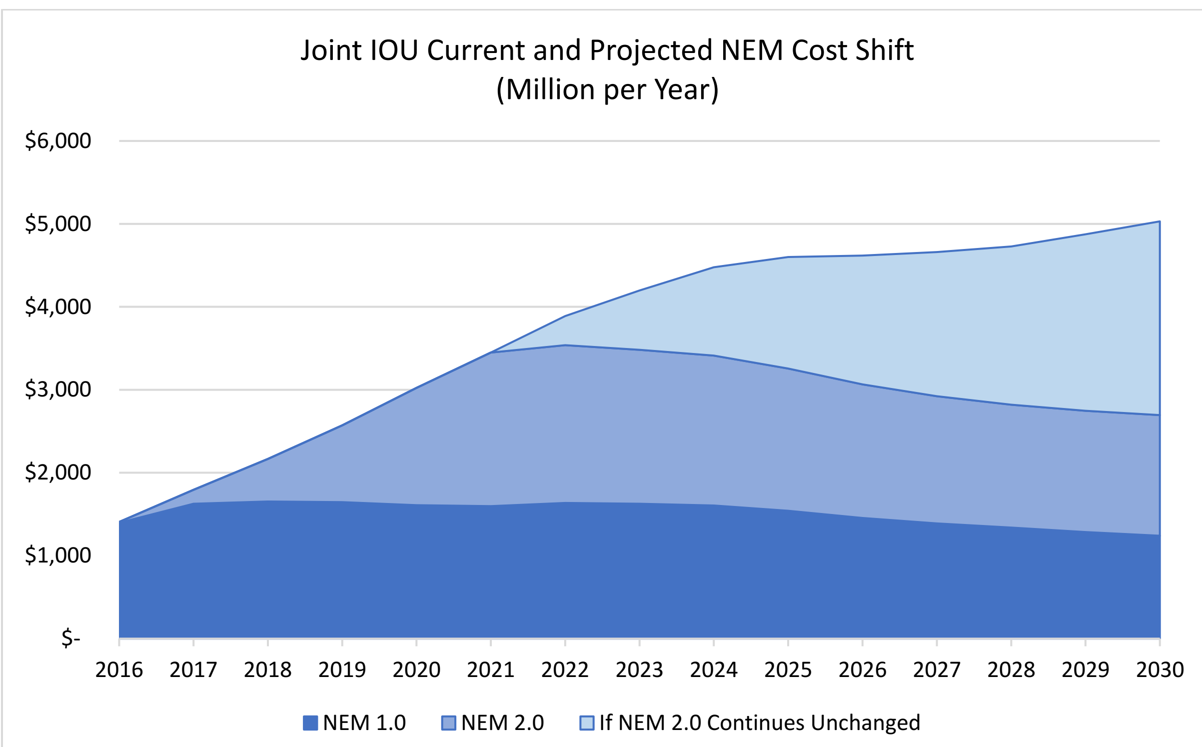
47/ Based on an analysis of customer call transcripts and feedback from PG&E's Solar Customer Service Center Customer Service Representatives.

ratio of less than 1 (even further below 1 if the impact from the federal Investment Tax Credit is removed). Looking specifically at customer rates measured by the Ratepayer Impact Measure (RIM) test, the Lookback Study found that, on average, resources taking service under a NEM 2.0 tariff have a RIM score well below 1, highlighting that the NEM 2.0 program may result in an increase in rates for all ratepayers. The cost of service analysis provides similar results. Looking specifically at residential customers, the Study highlights that residential customers on a NEM 2.0 tariff pay lower bills than the utility's cost to serve them, on average shifting costs to non-participating customers.

The Joint IOUs calculate the statewide cost shift created by the existing NEM programs to be $3.0 billion per year and growing. Without substantial change through this proceeding, this cost shift is projected to grow to $5.0 billion per year by 2030. The cost shift measures the financial benefits to participants (bill savings) that are not shared by the system or non-participants (avoided costs). An effective successor tariff will mitigate these issues and put in place an alternative that fairly compensates participants without unfairly impacting those who cannot participate.

However, even if the CPUC adopted a tariff that created zero cost shift to nonparticipants, the cost shift from existing participants will continue to increase, as their NEM compensation continues to be tied to retail rates. Today, there is a $3.0 billion cost shift annually from NEM 1.0 and 2.0 customers. These customers will continue shifting costs for their entire 20-year legacy period. A customer who adopts today will have a legacy period until 2041.

Figure 6



This is largely due to the 20-year legacy period adopted in D.16-01-044. This period was chosen to ensure that participants have a reliable expectation for rate stability when making an investment in a DER.[48/] However, this 20-year period comes at the expense of non-participants. Also, legacy participants are not only obtaining fast system payback, but also a substantial return on their investment. Current analysis shows that 20 years far exceeds the time necessary for residential customers to achieve payback under the current tariff and current rates. The Commission's Energy Division has recognized the issue caused by the legacy period and specifically seeks to avoid it in other proceedings, stating "tariffs can be closed at any time upon Commission approval of an application by the IOU or on the motion of Energy Division, including the tariff established by this decision. Parties should remember this because we intend to avoid the legacy issues that persisted with NEM."[49/]

Further, existing NEM programs have exacerbated wealth disparity. NEM 1.0 and 2.0 customers tend to be wealthier homeowners in high-income areas, on average,[50/] meaning that those who are better off are shifting costs to those who can least afford those costs. The fact that many of the inequities we see under the current tariff are locked in for years to come only heightens the urgency to create a more cost-effective successor tariff. While this proposal is not suggesting changes to the tariffs for existing customers, it is important to emphasize the lasting impacts that the existing tariffs have had. The 20-year legacy period has locked in these cost shifts for decades to come, making it all the more important that the Commission approves a fair and sustainable tariff for future customer-generators. At the end of a customer's 20-year legacy period, the Joint IOUs propose customers are defaulted to the DG-ST.

When NEM 2.0 was adopted, the Commission tried to mitigate the cost shift through the addition of NBCs and mandatory TOU rates. However, external factors limited the scale of change that could be made at the time. The 2016 decision stated:

> As is evident from this brief summary of the extensive work reflected in D.15-07-001, central aspects of residential rates, both rate design and actual charges to be imposed on residential customers, are slated to change significantly in the next few years. **This agenda for change to many aspects of residential rates has a significant impact on the question whether to make major departures from the existing NEM tariff in the successor tariff.** This impact has at least two aspects: concern for how much change residential customers choosing the NEM successor tariff should be asked to absorb in the near term; and caution about creating elements of the NEM successor tariff that may wind up either duplicating or undermining the larger process of making changes to residential rates to which the Commission is already committed.[51/]

Currently, all IOU residential customers are expected to be defaulted to TOU rates by March 31, 2022. When these structural changes are completed, a more comprehensive overhaul of the next successor tariff would be appropriate.

VIII. QUESTIONS FROM E3 WHITE PAPER

The E3 White Paper commissioned by the CPUC asked several specific questions to inform the design of the DG-ST. The Joint IOUs have addressed many of these issues above within our proposal. The Joint IOUs provide consolidated responses here.

48/ D.16-01-044, p. 4.

49/ R.19-09-009, pp. 48-49.

50/ Lookback Study, pp. 32-36.

51/ D.16-01-044, p. 19 (emphasis added).

1. **What is a reasonable payback period for behind-the-meter generation?**

There is no legislative requirement for a reasonable payback period for behind-the-meter renewable generation. That legislative requirement cited in the E3 White Paper applied only to NEM 1.0 customers. The Joint IOUs note that the payback periods achieved by the Joint IOU proposal are reasonable and consistent with those in other jurisdictions that have reformed NEM (Figure 3), particularly when considering the significant level of behind-the-meter renewable penetration in the three IOU territories.

While there is no legislative requirement for a specific payback period for NEM installations, the Joint IOUs strongly support providing accurate information of expected payback periods, including an understanding of underlying assumptions, so that customers are empowered to make the best energy choices for their preferences. Understanding the expected payback for an average NEM customer is an important data point to evaluate the existing NEM program from an operational perspective. However, specific paybacks will differ from customer to customer. To this end, the Commission should seek to establish a consistent methodology for calculating payback under various scenarios, such as falling technology costs or rate changes.

The Joint IOUs do not recommend developing rates around targeted payback periods. DERs are an investment and, like any investment, come with an inherent set of risks. It is crucial to offer accurate information to consumers so that they can determine whether to invest in DERs. However, similar investments do not offer guaranteed returns on investment, regardless of their contribution to policy goals. For example, electric vehicles may offer a payback on purchase price in a relatively short time if they are purchased when gas prices are high, but there is no market mechanism to compensate electric vehicle owners if gas prices drop following the purchase of the vehicle.

2. **Over what period of time should more cost-based retail rates for customer-generators be implemented? How can this rate transition best support other policy goals such as promoting electrification as a key decarbonization strategy?**

The Joint IOUs do not support an additional transition credit to all customers given (i) the size of the existing cost shift and (ii) that it will have been nearly a decade since the passage of AB 327 by the time the new NEM tariff is implemented. The Joint IOUs support a transitional discount for income-qualified customers that install NEM during the first three years of the new DG-ST tariff, to be revisited in a CPUC workshop to be held one year prior to expiration.

3. **How should a Market Transition Credit (MTC) for customer-generators be structured?**

The Joint IOUs do not support a MTC for all customers. For income-qualified customers, the Joint IOUs support a transitional discount to the Grid Benefits Charge. The Joint IOUs believe an adjustment to a fixed component of the bill (though not to export compensation), will provide more stability and predictability for these customers.

4. **Should MTC vintages be based on time (e.g., annual), number of participants, or capacity (e.g., MW blocks)?**

Any transition credit should avoid creating additional complexity by limiting the number of vintages to the extent possible. The Joint IOUs propose a transition period of three years for income-qualified customers. From an implementation and customer understanding perspective, triggers based on dates (instead of numbers of participants or installed capacity) are preferred. It is also easier for utility billing systems to manage fewer vintages.

5. **From which groups should the MTC recovery surcharge be collected? From the *same vintage* of customer-generators, *future vintages* of customer-generators, *all* customer-generators, all *ratepayers*, or some other group?**

If an MTC is approved and applied to successor tariff customers, as outlined in the E3 White Paper, the MTC should be collected from some or all customer-generators. Given the significance of the cost shift and the fact that non-participants will continue to subsidize existing NEM customers for decades to come, the Joint IOUs do not believe it would be fair to continue to ask these non-participants to subsidize new NEM installations through a MTC.

IX. TARIFF IMPLEMENTATION

A. Implementation of the NEM Successor Tariff

Upon issuance of a final decision adopting the successor tariff, the Joint IOUs should be required to file their successor tariffs via advice letter for review and approval by the Energy Division. Each utility's billing system environment and activities are different. Although the IOUs' successor tariffs structure and conditions will be aligned, implementation timeframes will differ. Each IOU shall implement their own successor tariff as soon as is practicable.

The Joint IOUs expect that substantial modifications would need to be made to multiple systems (billing system, print bill software, utility website, etc.) in order to bill customers on the DG-ST. Based on the Joint IOU proposal and planned billing system activities in 2021 through 2023, the initial estimate of time that would be required to (i) file implementation advice letters with associated tariffs and forms, (ii) identify requirements, code and test system changes, and (iii) finally implement the DG-ST, would be from 12-24 months following issuance of a final decision. This timing also assumes a dependency of the completion of the ACC methodology.

B. Marketing Education and Outreach (ME&O)

The Joint IOUs recommend that communications be developed and targeted towards both existing NEM customers and prospective successor tariff customer-generators, as well as solar providers and developers. ME&O will vary depending on the successor tariff structure that is ultimately adopted by the Commission. The Joint IOUs suggest that ME&O activities to communicate the tariff to new customers and separately, transitioning customers, can be reviewed and approved by Energy Division staff via the advice letter process.

C. Coordination with Other Proceedings

Per the Joint IOU proposal, the export compensation will be tied to the ACC which will be updated per the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, as outlined in D.19-05-019, or in a successor proceeding to R.14-10-003. There are proceedings that involve DG-ST customers and systems (including interconnections)[52/] that could potentially impact implementation timing or ongoing operation of the NEM successor tariff. Directives in other proceedings that require changes to the Joint IOUs' respective billing systems may delay implementation of a NEM Successor Tariff.

52/ OIR to Revisit Net Energy Metering Tariffs Pursuant to Decision D.16-01-044, and to Address Other Issues Related to Net Energy Metering, R.20-08-020, August 27, 2020, p. 7.

D. Cost-Effectiveness Evaluation

Regardless of the proposal adopted by the CPUC in this proceeding, the Joint IOUs propose that the CPUC order a cost-effectiveness evaluation of the adopted successor to be completed two years after successor tariff implementation and that the Commission approve funding for that effort in this proceeding. The CPUC-commissioned NEM 2.0 cost effectiveness evaluation that was completed by Verdant in January 2021 provided useful information on the effectiveness of the existing NEM program, including providing insights about mechanisms to improve the process going forward. Cost-effectiveness of the successor tariff will demonstrate whether the adopted structure meets the principles adopted in this decision or whether additional changes are necessary.

X. LIST OF ACRONYMS

Acronym	Description
AB	Assembly Bill
ACC	Avoided cost calculator
CAISO	California Independent System Operator
CARE	California Alternate Energy Rates
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CSGT	Community Solar Green Tariff
CSIP	Common Smart Inverter Profile
CSLB	California State Licensing Board
DAC	Disadvantaged Communities
DFPI	Department of Financial Protection and Innovation
DG-ST	Distributed Generation Successor Tariff
DER	Distributed energy resources
ECR	Export compensation rate
EPMC	Equal percentage of marginal costs
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
IEEE	Institute of Electrical and Electronics Engineers
IDER	Integrated Distributed Energy Resources
IOU	Investor Owned Utilities
IRP	Integrated Resource Plan
kW-DC	Kilowatts-direct current
kWh	Kilowatthour
kW	Kilowatt
LIWP	Low-Income Weatherization Program
MASH	Multifamily Affordable Solar Housing program
ME&O	Marketing, Education and Outreach
MTC	Market Transition Credit
MW	Megawatt
MWhs	Megawatthours

Acronym	Description
NBC	Non-bypassable charges
NCCEC	North Carolina Clean Energy Center
NEM	Net Energy Metering
NEMA	Net Energy Metering Aggregation
NREL	National Renewable Energy Laboratory
NSC	Net Surplus Compensation
NSHP	New Solar Homes Partnership
PCT	Participant cost test
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PV	Photovoltaic
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SAM	System Advisor Model
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SOMAH	Solar on Multifamily Affordable Housing
TOU	Time of use
TOE	Time of export
VNEM	Virtual Net Energy Metering
VODE	Value of Distributed Energy

APPENDIX 1

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*

Table of Contents

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.

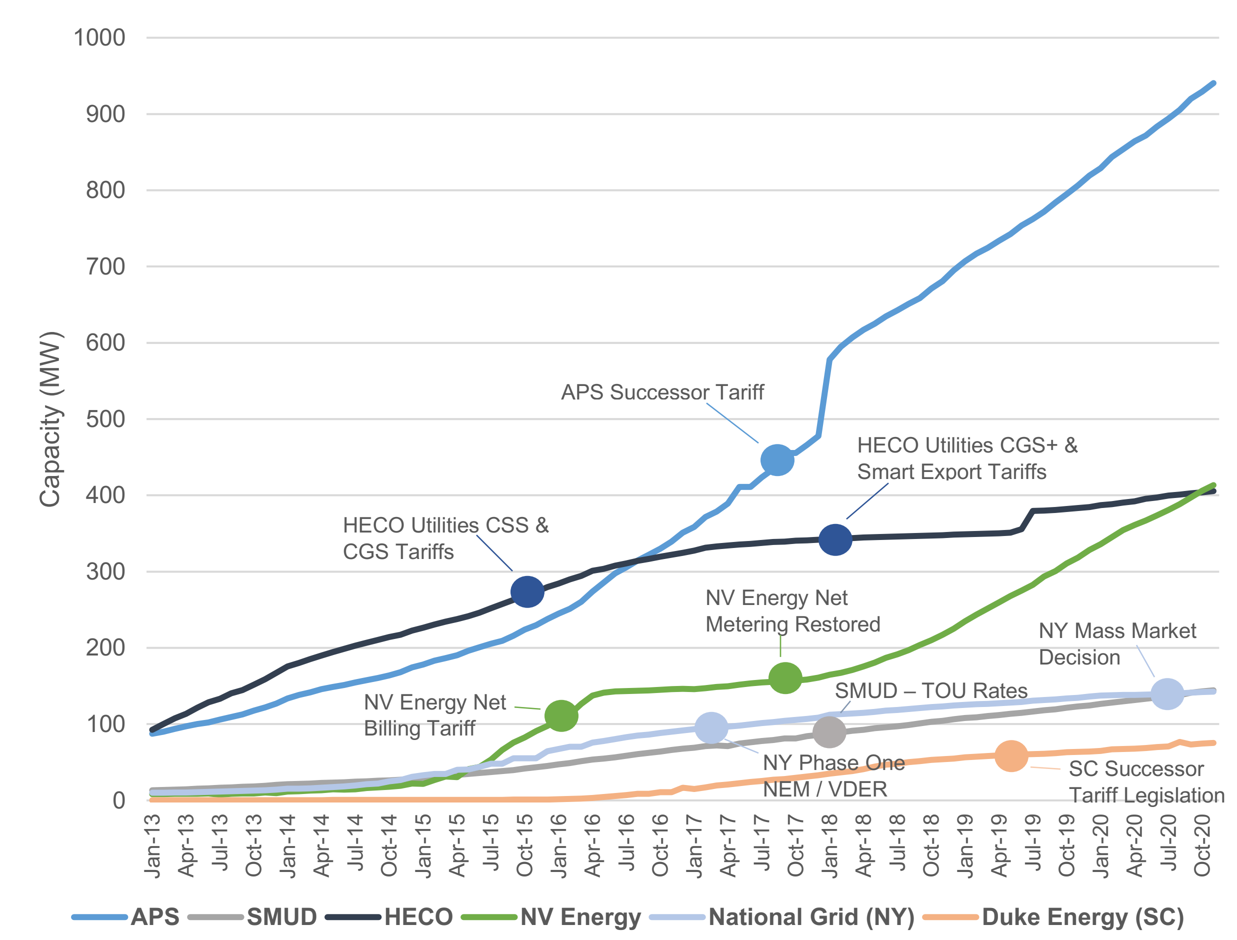
[1] Galen Barbose, Naim Darghouth, Eric O-Shaughnessy, and Sydney Forrester. Lawrence Berkeley National Laboratory. *Tracking the Sun Distributed Solar 2020 Data Update*. December 2020. https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf.

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.

---

[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.

[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.

[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

[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]

---

[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

---

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:

---

[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:

---

[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,

---

[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/8a5f3592472a270c8525808800517bdd/$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.

---

[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/sciderrnm.pdf?la=en; Rider RNM (DEP). https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/rr20sciderrnm.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.

[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]

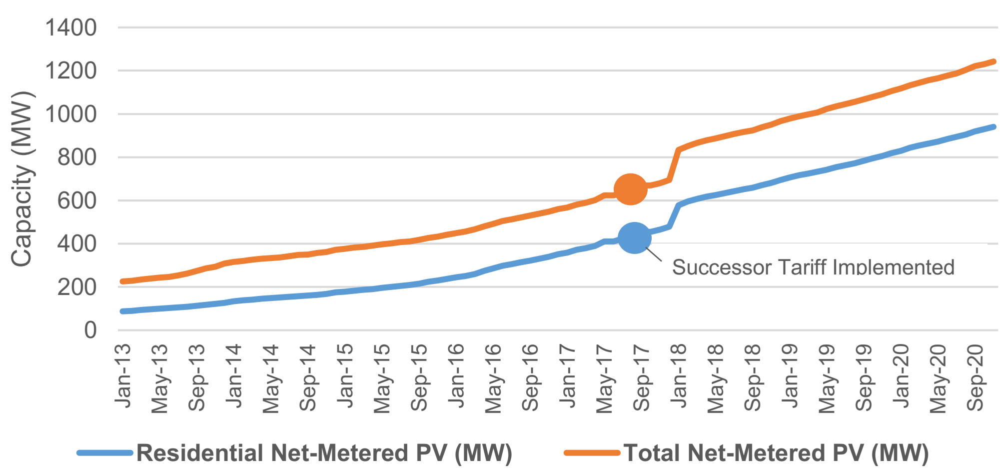
- Instantaneous netting period. Current export credit rate of $0.1045 per kWh – credit is locked in for 10 years *(Note: analysis uses this rate for the full 20 years)*

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]

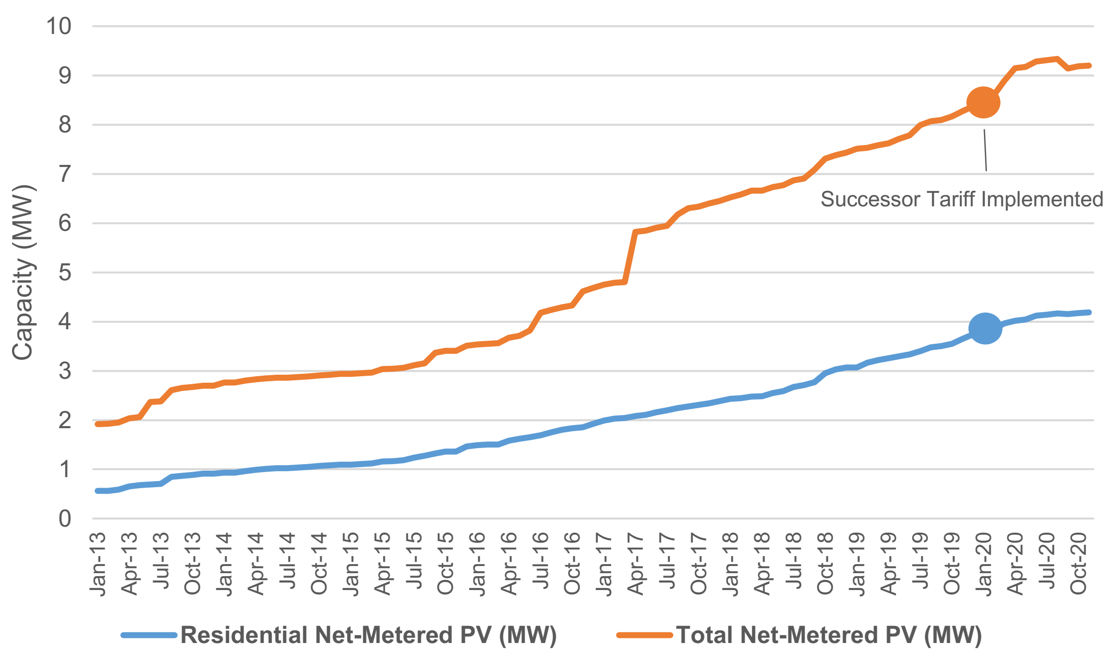
- Export credit rate of 4.865 cents per kWh for on-peak energy and 3.699 cents per kWh for off-peak energy

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]

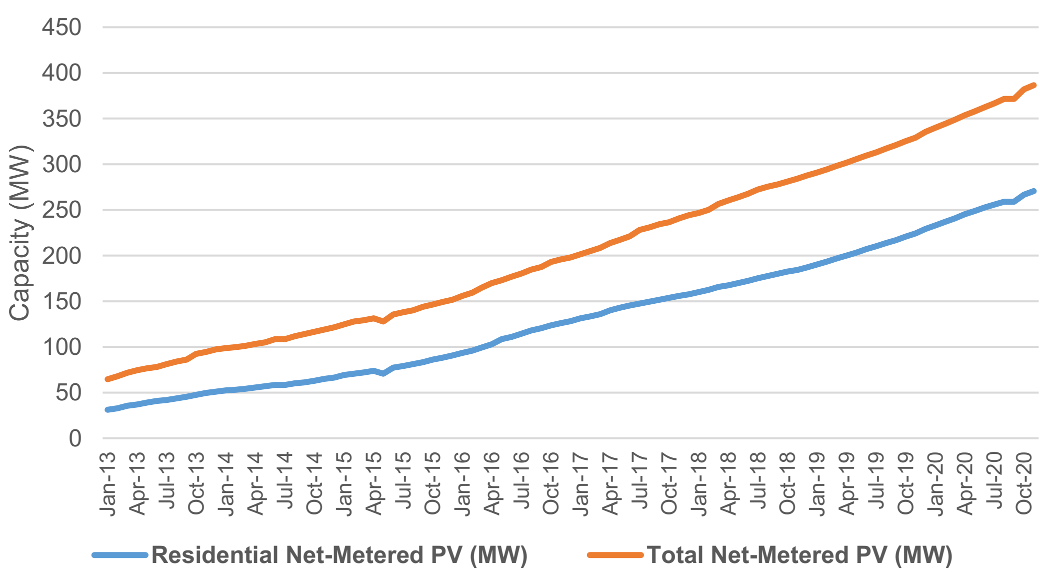
- Retail rate net metering
- Net excess generation may carry forward indefinitely

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]

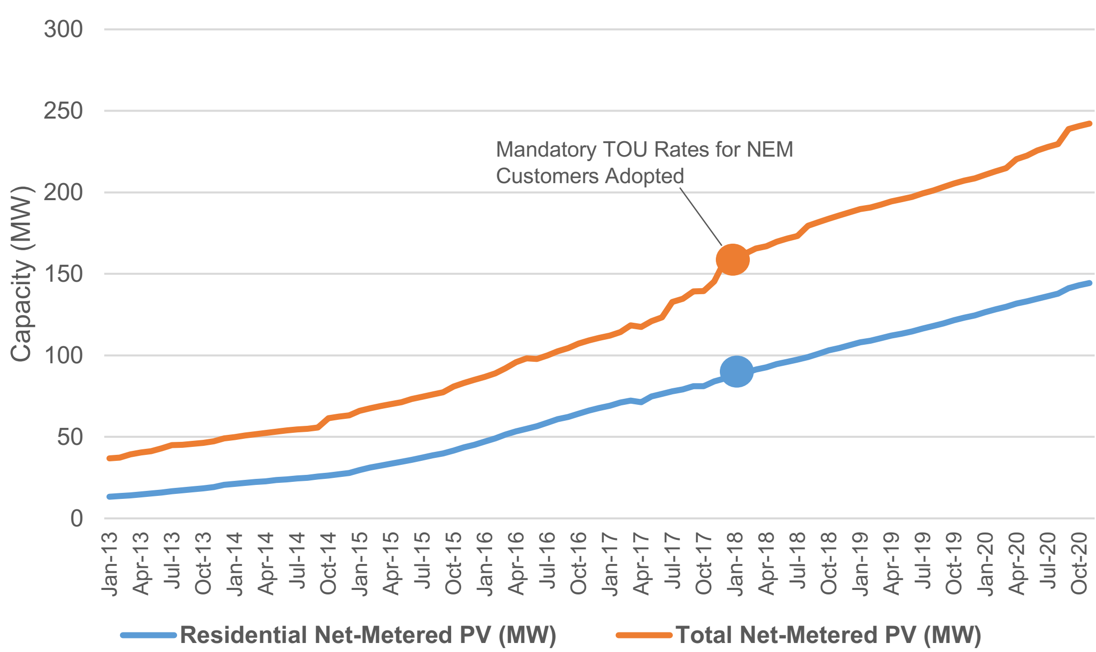
- Retail rate net metering with mandatory TOU rates
- Annual net excess generation may be paid out at 5.62 cents/kWh or carried forward
- Customers will be subject to NEM successor tariff currently under development

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:

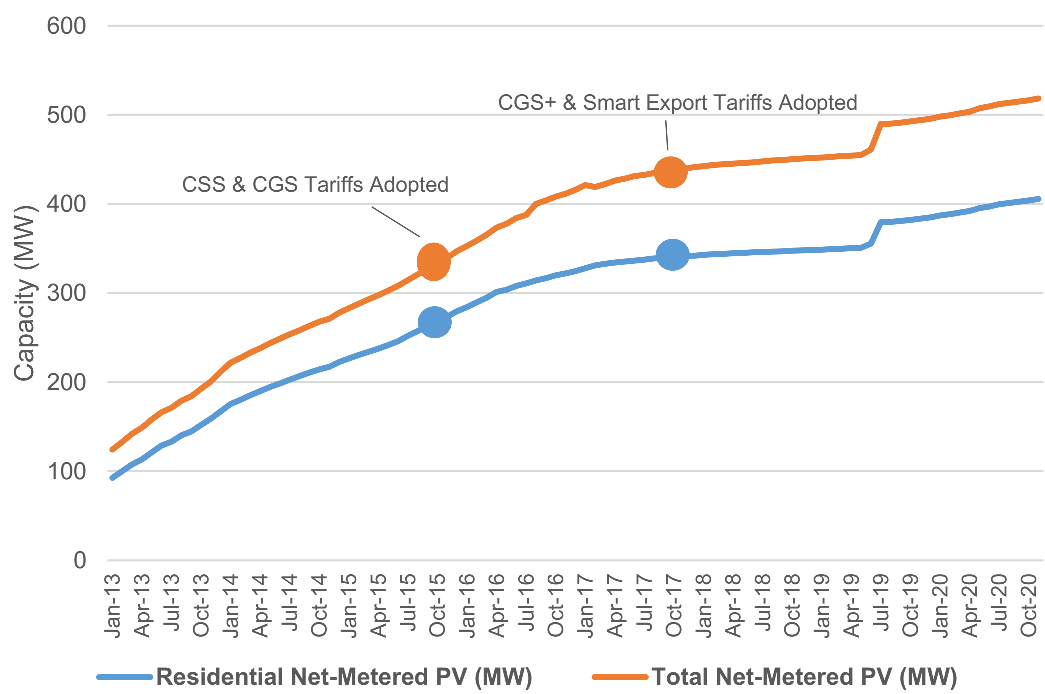
- Customer Grid Supply Plus:
  - Hawaii Island (HELCO) – 10.55 cents per kWh
  - Maui (MECO) – 12.17 cents per kWh
  - Molokai (MECO) – 16.77 cents per kWh
  - Lanai (MECO) – 20.80 cents per kWh
- Smart Export:
  - Hawaii Island (HELCO) – 11.00 cents per kWh
  - Maui (MECO) – 14.41 cents per kWh
  - 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]

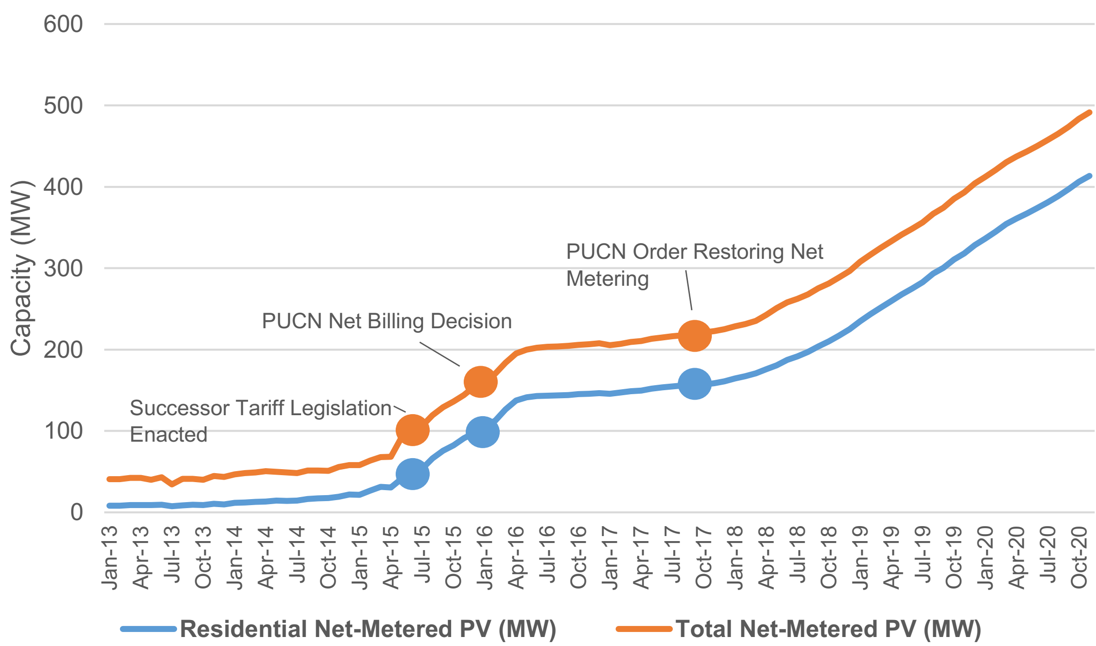
- Retail rate net metering
- Monthly net excess generation credited at 75% of retail rate (Tier 4) – rate applies for 20 years

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]

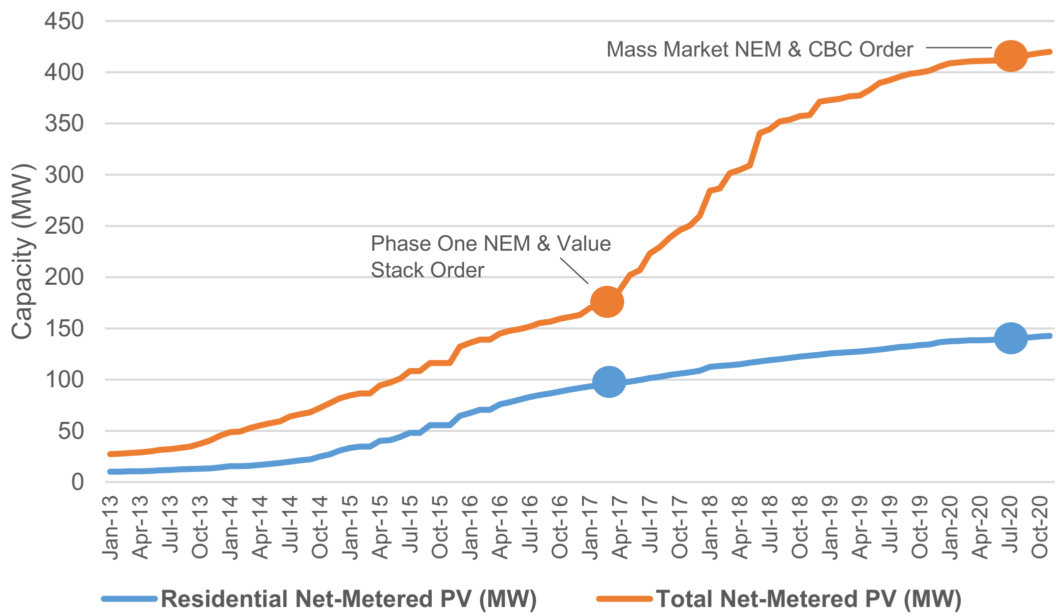
- Mass Market successor tariff to take effect in 2022
- Retail rate net metering
- Includes $1.15 per kW-DC customer benefit contribution

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]

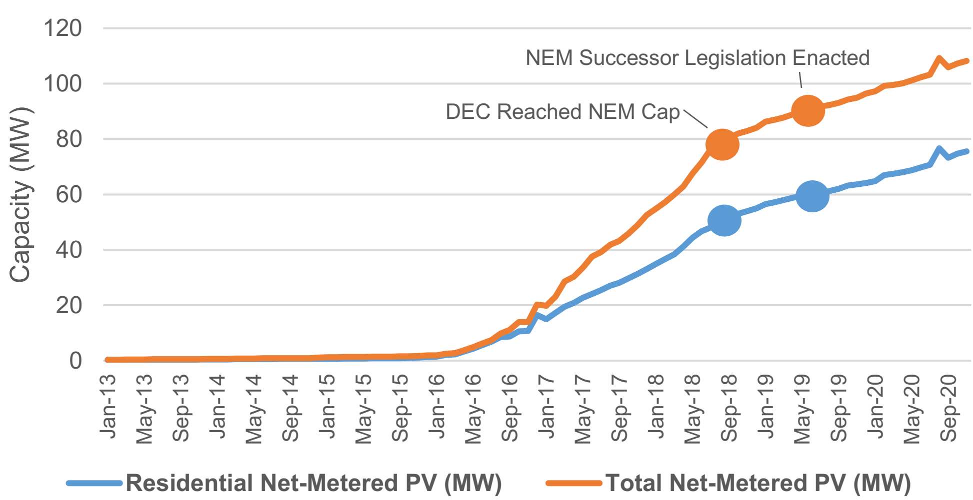
- Time-of-use net metering
- Monthly net excess generation credit rate of $0.027 per kWh

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.



Payback Analysis Sources

---

[i] https://openei.org/doe-opendata/dataset/eadfbd10-67a2-4f64-a394-3176c7b686c1/resource/cd6704ba-3f53-4632-8d08-c9597842fde3/download/buildingcharacteristicsforresidentialhourlyloaddata.pdf

[ii] https://www.eia.gov/electricity/data/eia861/

[iii] https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors

[iv] https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors

[v] https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors

[vi] https://www.aps.com/en/Residential/Service-Plans/Compare-Service-Plans/Renewable-Energy-Riders#RCPExportRider

[vii] https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/rates/D_Residential_Service.pdf

[viii] https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/rates/NB-136_Net_Billing_Service.pdf

[ix] https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-electricrateschedules?_afrLoop=405594361060422&_afrWindowMode=0&_afrWindowId=a4k1fye3s_1#%40%3F_afrWindowId%3Da4k1fye3s_1%26_afrLoop%3D405594361060422%26_afrWindowMode%3D0%26_adf.ctrl-state%3Da4k1fye3s_110

[x] https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-electricrateschedules?_afrLoop=414654265278504&_afrWindowMode=0&_afrWindowId=a4k1fye3s_107#%40%3F_afrWindowId%3Da4k1fye3s_107%26_afrLoop%3D414654265278504%26_afrWindowMode%3D0%26_adf.ctrl-state%3Dtffyacua2_4

[xi] https://www.smud.org/-/media/Documents/Electric-Rates/Residential-and-Business-Rate-information/PDFs/1-R-TOD.ashx

[xii] https://www.smud.org/-/media/Documents/Electric-Rates/Residential-and-Business-Rate-information/PDFs/1-NEM1.ashx

[xiii] https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rates/heco_rates_sch_r.pdf

[xiv] https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/18.pdf

[xv] https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/24.pdf

[xvi] https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/25.pdf

[xvii] http://www.sale-tax.com/HonoluluHI

[xviii] https://www.solarreviews.com/solar-panel-cost/hawaii

[xix] https://www.energysage.com/solar/solar-energy-storage/what-do-solar-batteries-cost/

[xx] https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/StatementofRates.pdf

[xxi] https://www.nvenergy.com/account-services/energy-pricing-plans/net-metering/nmr-405

[xxii] https://ets.dps.ny.gov/ets_web/search/searchShortcutEffectiveAction.cfm?M%3FIW%3F%21ZQOH%25NL%40LNR%3C%2BR%3F%2BXTWD8AM%3F%263%40JZ%3E%3EME%2AOC9%3E4J%292TH%21J%3EH%2AK%3D%26%28VP%0AMLF%5EGL%2A%5F%25AKO%2BS%5EH%3BQO%5F%2E%23%5C%2DD4%3B%2F%2FO%20%2AVBMFR4K%3BHJ%3A%22%26LEZ%5BEA642%212%3E%24%3B%3E%2E%0AMM5%26%5BD%28%5C%2CWG%26%5D%5BI%2E%21%5FXNPV95%22B7%3F%3DL%28%2A88%25FCK%3EZM%27%5C%5C4K9Z%5CI%3AG9IJJ8VK%22%3A%0AH%26%22Z%5C6%29VRC%26%3EDF3%3F%3AJ%26%3AM%5DUF2GWR%2C%5CL%22H2U%2C5M9R%5F%3C7X%5EO%40QROL%28%21H%20%20%20%0A

[xxiii] https://www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/upstate-ny/average-prices-ending-december-31-2020.pdf

[xxiv] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751

[xxv] https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives/Upstate-Dashboard

[xxvi] https://dms.psc.sc.gov/Attachments/Matter/9dc8574f-5814-4466-aa0f-ca0df5eab87b

[xxvii] https://dms.psc.sc.gov/Attachments/Matter/9dc8574f-5814-4466-aa0f-ca0df5eab87b

[xxviii] http://www.sale-tax.com/GreenvilleSC

[xxix] https://smartasset.com/taxes/south-carolina-property-tax-calculator