California Public Utilities Commission

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Alternative Ratemaking Mechanisms for Distributed Energy Resources in California

Successor Tariff Options Compliant with AB 327

Energy+Environmental Economics

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Executive Summary

The California Public Utilities Commission (CPUC) engaged Energy and Environmental Economics, Inc. (E3) to support and facilitate the development of proposals for a net energy metering (NEM) successor tariff that will be compliant with California legislation. In particular, Assembly Bill (AB) 327 of 2013 requires the CPUC to reform the existing NEM program in a manner that better aligns compensation for customer-sited renewable generation with the net benefits that it provides to the electric system, while preserving sustainable growth of behind the meter (BTM) renewable generation in California.

This paper includes E3's perspective on a framework that can meet these requirements. The paper begins with an overview of the existing misalignment between the bill savings NEM customers receive and the corresponding impact or value of this generation to the utility (avoided costs). This cost misalignment was most recently examined in the *Net-Energy Metering 2.0 Lookback Study* completed by Verdant Associates.[1] This white paper illustrates that immediate elimination of the cost shifting under the current NEM program would be very difficult to achieve, as it would cause severe bill impacts and could make it challenging to maintain a viable customer-sited renewable generation industry in the state.

Preservation of a viable market is likely to require a "glide path" including both a gradual rate reform and an external transitional support mechanism designed specifically to enable a reasonable payback period for customers investing in onsite renewable generation. Such a mechanism, which we refer to as a market transition credit (MTC), would be flexible and sensitive to cost declines for customer-sited renewable generation, and especially BTM solar. The MTC would be fixed over a defined payback period for each NEM vintage, based either on time (e.g., annual vintages), number of subscribed customers, or the volume of adoption of customer-sited renewable generation. The MTC provided to new vintages would be phased out in a transparent and gradual manner as customers with onsite renewable generation become increasingly able to face electricity rates that are better aligned with underlying value. This transparency would provide needed certainty to developers of customer-sited renewable generation, allowing for planning around expected rate changes and MTC declines and in turn enabling improved project financing.

E3 believes that a central element of the proposed framework is the design of a mandatory new successor rate for customers with onsite renewable generation, which will increase efficiency in adoption of BTM generation while also producing more equitable outcomes than the current NEM program. This rate would not be required for nonparticipating customers, although enrollment would be open to all. At this initial stage in the successor tariff development, the white paper does not advocate for a specific rate structure, but we identify a number of potential successor rate options that represent an improvement over current residential and small commercial rates. All such candidate successor rate options would enhance equity by more rigorously incorporating cost causation and other ratemaking principles in setting the various rate components. Together with a newly adopted multi-part rate for customers with onsite renewable generation, we believe that a departure from the traditional NEM compensation structure is necessary, replacing retail rate-based credits for energy injections into the grid with export rates that reflect avoided costs and are time-of-day and seasonally differentiated.

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[1] The *Lookback Study* was prepared for the Commission by Verdant Associates, in collaboration with E3 and Itron, Inc. The report is available at: https://www.cpuc.ca.gov/nem2evaluation.

To support the various proposals and analyze the potential size of the MTC, this paper develops illustrative rate examples. In designing these rates, we have assumed that during the transitional period customer-generators would contribute more towards fixed costs of service than under the current NEM 2.0 program.

The successor rate would not be fully cost-based in the initial stages in order to limit the size of the MTC needed to provide a reasonable payback for customer-generators' investments. During the transitional period, the MTC would be implemented along with a tracking mechanism to capture the imbalance between the successor tariff revenue and the system avoided cost value provided by onsite renewable generation.

In addition to tariff changes and transitional mechanisms such as the MTC, *time* represents an important dimension in this discussion and can be used to guide the level of gradualism or speed at which this transition takes place. The method used to decide when and how rates should be modified and adjustments to the MTC would consider impacts on customer-generators' bill savings and the related return on investment. Table 1 provides a comparison of these dimensions.

Table 1. Illustrative Interaction Between Tools for Distributed Energy Resource Cost & Value Alignment

	Near-Term	Medium-Term	Long-Term
Rate of Change	*How quickly to transition? (Time and Adoption Volume-Based Factors)*		
Rate Design	Initial improvement in alignment between retail rate and system avoided costs, narrowing current gap	Further customer-sited renewable generation cost decline and improved rate alignment / reduced gap	Retail rates accurately reflect underlying system costs by time of day
Market Transition Credit	MTC provides necessary savings to meet remainder of this gap (i.e., providing the "missing money")	Adjust MTC to assure that it is sufficient to provide required returns, as technology costs decline and/or tax policy changes	MTC phases out as customer-sited renewable generation system costs continue their decline to sufficiently provide necessary payback

The rate examples in this paper show that it is possible to make optimistic assumptions as to the declining trend of BTM solar costs, making it easier to provide both reasonable investment opportunities for new customer-generators and to reduce the MTC over a reasonably short period. However, the introduction of an external ratemaking mechanism like the MTC would allow for slower but continued rate progression even in a less optimistic scenario.

The figures below (described in further detail in Section 7) provide two illustrative examples of how vintages of rate changes and technology cost declines can interact to produce a desired payback for investments in customer-sited renewable generation. In the first example (Figure 1), technology costs are assumed to decline sufficiently that the savings required to produce the desired payback remain below the value of bill reductions provided to the customer-generator, indicating no need for additional support. In the second example (Figure 2), alternatively, technology costs are assumed to remain sufficiently high that a MTC is required to provide the savings necessary to produce the desired payback period. The ability to adjust the MTC – based on declining technology costs or the desired payback period – is one of its most valuable attributes. This flexibility also enables the MTC to be calibrated differently for distinct groups, for example, to provide additional support to underserved or disadvantaged communities.

Figure 1. Bill Reductions and MTC, Optimistic Scenario

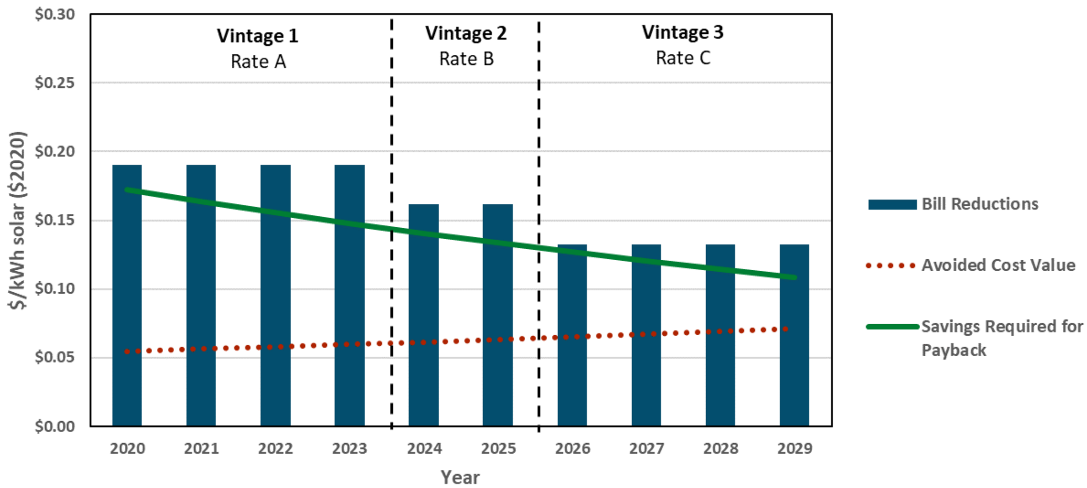
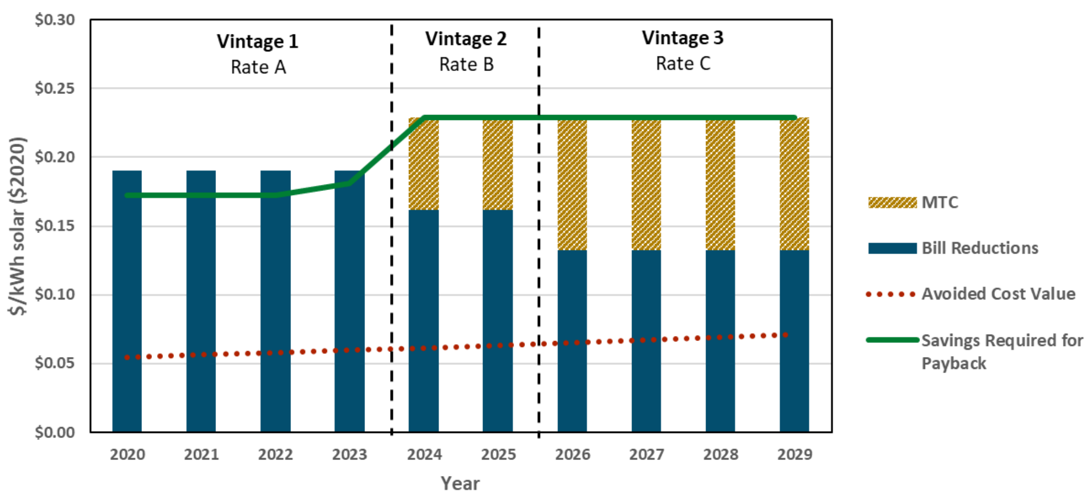


Figure 2. Bill Reductions and MTC, Flat Technology Cost Scenario



The combination of increasingly cost-reflective rates and the flexibility of the MTC allow for gradualism in the transition to a compensation structure for customer-sited renewable generation that more accurately reflects underlying value while also supporting policy goals such as increasing electrification and reducing greenhouse gas emissions.

1. Introduction

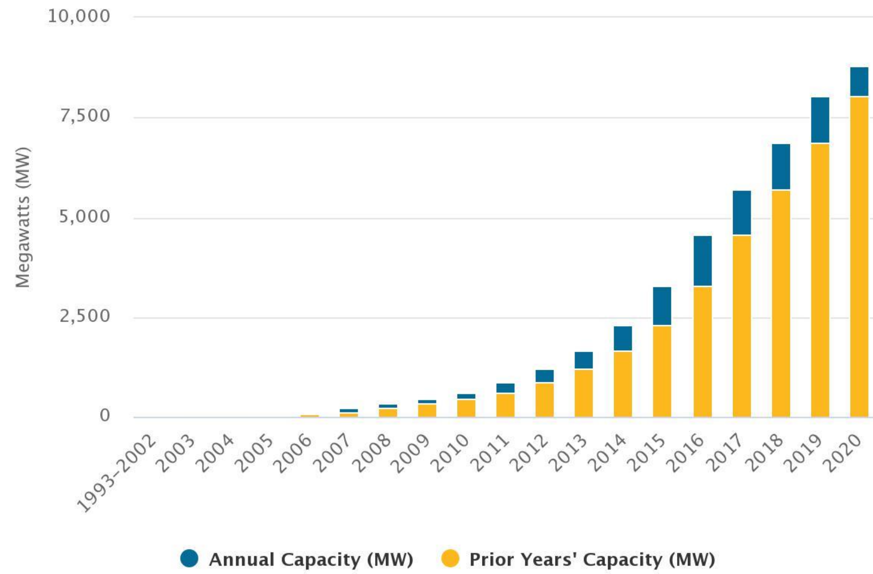
The California Public Utilities Commission (CPUC) engaged Energy and Environmental Economics, Inc. (E3) to support the development of a suitable successor to the current net energy metering (NEM) tariff that will be compliant with current California statutes. California's NEM program is applicable to customers installing solar, wind, biogas, and renewable fuel cell generation facilities that serve some of their onsite electricity needs.

Customers benefit from using onsite renewable generation for their own consumption, replacing utility-delivered energy valued at the applicable retail rate. Under the NEM program, the customers also receive a financial credit on their electricity bills for surplus energy fed back to the grid during times when it is not serving onsite load based on the prevailing retail rate.[2]

For decades, the NEM program has played an important role in encouraging customer-sited renewable generation to develop in California and in particular customer-sited solar. Since the inception of the NEM program, behind-the-meter (BTM) solar capacity in California has continued to grow due to a combination of declining technology costs, state and federal incentives, and the attractive economics offered by the NEM program (Figure 3). Current BTM solar capacity is over 8,500 MW, making California the national leader in customer-sited generation.

[2] NEM customer-generators must pay the same nonbypassable charges for public services as other IOU customers, which includes Department of Water Resources' bond charges, the public purpose program charge, nuclear decommissioning charge, and competition transition charge. NEM customer-generators are exempt from standby charges.

Figure 3. California BTM Solar Penetration, Large Investor-Owned Utilities[3]



The continued use of NEM as a compensation mechanism creates equity concerns between customer-generators and nonparticipating customers. This is because there is a large misalignment between the compensation provided for customer-sited renewable generation – which relies on retail rate per-kWh charges (including generation, transmission, and distribution cost components) – and the cost savings the utility accrues from the output of customer-generators' systems.

The recent *Net-Energy Metering 2.0 Lookback Study* completed by Verdant Associates, with input from E3 and Itron, found that the compensation given to participating NEM customers for load reductions and grid exports greatly exceeds the incremental benefits.[4] This misalignment leads to higher bills for non-NEM customers, as retail rates must increase to make up for the unrecovered utility costs. Recognizing this misalignment between value and compensation, in 2013 California Assembly Bill (AB) 327 required the CPUC to adopt a successor tariff to NEM. The successor rate would better align the costs and benefits of customer-sited renewable generation while also ensuring that these generation sources continue to grow sustainably in the state.

Meeting the directives of AB 327 requires a rate mechanism that precludes the shifting of non-avoidable, fixed costs of serving customer-generators to nonparticipating customers. The choice of a rate framework that ensures best practice must treat customer-generators comparably to nonparticipating customers, while at the same time maintaining a viable value proposition to customers investing in onsite renewable generation, as measured by providing a reasonable payback period. Accordingly, this report provides

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[3] California Distributed Generation Statistics. California Solar Initiative. Accessed November 17, 2020. Data current through August 31, 2020. Available at: https://www.californiadgstats.ca.gov/.

[4] E3 notes that while similar subject matter is covered in both the *Lookback Study* and this white paper, these efforts are distinct and separate, with neither superseding the other.

recommendations on principles, rate design changes and ratemaking mechanisms that can be used to bring the existing NEM program into alignment with AB 327.

The proposals contemplated in this white paper are bounded and informed by several critical factors, including California legislation, the findings from previous proceedings on NEM, and the recent *Net-Energy Metering 2.0 Lookback Study* completed to inform the CPUC of the costs and benefits of the current tariff.[5]

The structure of the white paper is as follows:

- Section 2 provides background.
- Section 3 discusses the key elements of the framework to address cost misalignment.
- Section 4 describes the market transition credit as a transitional mechanism.
- Section 5 discusses alternative potential rate structures that would more efficiently meet AB 327 objectives while also meeting other important objectives in California, such as electrification.
- Section 6 presents several illustrative rate design examples and discusses their impacts.
- Section 7 provides two examples of the gradual transitional ratemaking mechanisms we describe.
- Section 8 includes the main conclusions of the proposed framework as well as specific questions for stakeholder input.
- The Appendix includes a summary of how other jurisdictions addressed similar NEM reform needs.

2. Background

Legislative and Regulatory Background

The NEM program was established by Senate Bill (SB) 656 in 1995 and different statutes have revised the program in various ways since its inception. For the state's three large electric investor-owned utilities (IOUs)[6], the NEM program is regulated by the CPUC. AB 327 mandated that the CPUC adopt a successor to the NEM tariff that was in place at the time and laid out a number of objectives that this revised tariff should meet. Several of the primary objectives include ensuring that (emphasis added):

- Customer-sited renewable distributed generation "continues to **grow sustainably** and include specific alternatives designed for growth among residential customers in disadvantaged communities."[7]
- "Any rules adopted by the commission shall consider a **reasonable expected payback period** based on the year the customer initially took service."[8]

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[5] The *Lookback Study* is available at: https://www.cpuc.ca.gov/General.aspx?id=6442463430.

[6] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

[7] Pub. Util. Code § 2827.1(b)(1).

[8] Pub. Util. Code § 2827.1(b)(6).

- The standard contract or tariff for customer-sited distributed generation "is **based on the costs and benefits** of the renewable generating facility."[9]
- "[T]he **total benefits** of the standard contract or tariff to all customers and the electrical system are **approximately equal to the total costs**."[10]

In 2016, the CPUC adopted D.16-01-044, implementing part of the requirements of AB 327. D.16-01-044 adopted what is known as NEM 2.0. The Decision also committed the CPUC to revisit the NEM 2.0 tariff due to "interactive, yet unresolved, policy movements within the Commission, but outside the scope of the NEM proceeding."[11] Under NEM 2.0, new NEM customers must enroll in one of the optional time-of-use (TOU) rates and must also pay nonbypassable charges on each kWh of energy consumed from the grid to support public programs (as do other utility customers). Current NEM 2.0 residential and commercial customer-generators must also pay a one-time interconnection fee upon connecting their solar system to the electric grid. The fee was adopted to recover each IOU's estimated cost of interconnecting customer-sited renewable generators to reduce any socialization of interconnection costs in the retail rate that would be recovered from other customers.[12]

In September 2020 the CPUC began a new proceeding in Rulemaking (R.)20-08-020 to focus on 1) development of a successor to the existing NEM 2.0 tariffs pursuant to the requirements of AB 327, and 2) issues related to existing NEM tariffs, including but not limited to questions about or modifications to specific provisions of the NEM tariffs.[13] In order to base the successor tariff on "the costs and benefits of the renewable generating facility" as stipulated in AB 327, compensation to customer-generators will need to be reduced. Finding the appropriate balance between this requirement and the legislation's mandate that customer-sited renewable generation continues to "grow sustainably" will be the primary challenge in the creation of a successor tariff.

Findings of Cost Misalignment

The recently completed *Net-Energy Metering 2.0 Lookback Study* provided a detailed review of the NEM 2.0 tariff, concluding that the NEM 2.0 program provides significant bill savings for participating NEM customers that largely exceed the net benefits provided, equal to **total benefits** less **total costs**. For the purposes of this report, **total benefits** are based on the most recent avoided cost values adopted by the

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[9] Pub. Util. Code § 2827.1(b)(3).

[10] Pub. Util. Code § 2827.1(b)(4).

[11] Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.

[12] Customers with solar facilities under 1 MW pay a pre-approved standard fee (PG&E's fee is $145; SCE's fee is $75; and SDG&E's fee is $132). This white paper does not address the suitability of the current interconnection fee and assumes that it continues to reflect the additional costs of interconnecting a solar system not already recovered in retail rates. The costs of any upgrades needed upstream of the connection are not included in the fee, consistent to how those costs are socialized for all residential and small commercial customers. Customer-generators with systems over 1 MW must pay an $800 interconnection fee and additionally pay for any transmission/distribution system upgrades required to accommodate the interconnection, evaluated on a case-by-case basis by the utility.

[13] Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.

CPUC through the Integrated Distributed Energy Resources proceeding (R.14-10-003).[14] The CPUC avoided costs include values for GHG emissions, energy, generation capacity, transmission capacity, distribution capacity (excluding the cost of line transformers), losses and several other categories. **Total costs** are defined as the bill reductions NEM customers receive due to the total generation from their customer-sited renewable generation systems (i.e., bill reductions from onsite use as well as from exports) plus the cost of interconnecting these systems and the incremental metering costs incurred by the utilities to track their generation.

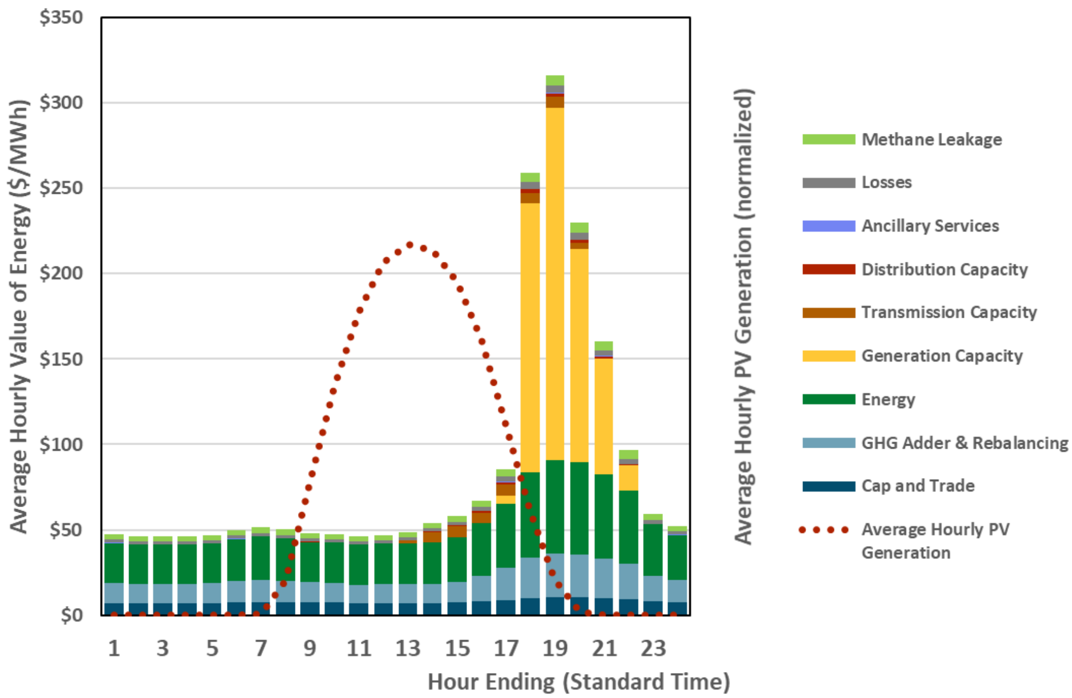
The requirement of having all customer-generators enroll in TOU rates as part of NEM 2.0 helped move compensation for customer-sited renewable generation closer towards cost causation but did not fully accomplish the alignment of costs and value.[15] Participating customer-generators continue to be able to benefit from the inefficiency inherent in electricity rates. There are two reasons for this inefficiency. The main reason is that, while time-differentiated, current residential TOU rates are not strictly reflective of the avoided (marginal) costs at different times of day. Additionally, the inclusion of fixed costs such as generation, transmission, and distribution capacity in the time of use volumetric energy charges makes the rate substantially higher than the underlying marginal cost of electricity. High volumetric rates encourage customers to reduce consumption and increase incentives for energy efficiency, but if prices exceed marginal costs, they will continue to allow customer-generators to avoid making contributions to the recovery of the fixed costs of the grid.

The second reason for cost misalignment is that the hours when customer-sited renewable generators (especially BTM solar systems) are producing maximum output do not coincide with the hours when customer demand on the electric system as a whole is peaking. This further weakens the justification of the current compensation under NEM, which includes a high above-marginal cost credit. To illustrate this, Figure 4 below depicts the hourly avoided costs from the 2020 Avoided Cost Calculator and compares these values with the hourly generation profile for a residential solar system, averaged across the year. While the majority of the solar photovoltaic (PV) generation takes place during the middle of the day, the higher marginal cost value falls between hours ending 16 through 21 (4 to 9 pm), which include almost the entire fixed generation capacity, transmission, and upstream (primary) distribution costs. In those higher-cost evening hours, solar generation declines rapidly and therefore does not provide meaningful capacity value. This comparison also demonstrates the significant potential additional value that battery storage can provide by shifting solar generation from the lower-value midday hours to the higher-value evening hours.

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

[15] Since the time NEM 2.0 was approved there have also been other changes to the underlying retail rates for all customers (NEM participants and nonparticipants), which improved the efficiency of the rates and affected the cost-benefit analyses of NEM. The two primary changes have been a flattening of the tiered rate structure that used to charge customers more per kWh as their usage during the month increased, and a requirement to enroll in TOU rates for residential customers.

Figure 4. 2020 Hourly Average Avoided Costs and Solar Generation, Annual Averages



Assessment of additional benefits beyond the CPUC's most recently adopted avoided costs are beyond the scope of this proceeding.[16]

Table 2 provides an excerpt of the weighted average benefit cost ratios found in the Net-Energy Metering 2.0 *Lookback Study*, for NEM solar and solar + storage systems across California's three large electric IOUs. A ratio greater than one indicates net benefits, while a ratio below one indicates net costs. There are net benefits for participating NEM customers (Participant Cost Test), driven by the bill savings they receive being well in excess of their costs to install solar or solar + storage. In contrast, there are net costs for nonparticipating customers (Ratepayer Impact Measure) due to the bill reductions NEM customers receive being well in excess of the cost reductions the utility receives from the behind the meter systems' generation. This discrepancy between the value provided to the utility and the value paid to NEM customers indicates a shifting of costs from NEM customers to nonparticipants.

[16] This is not to say that other benefits beyond those adopted in R.14-10-003 do not exist, but rather to clarify the use of the term "total benefits" for the purposes of this paper. For example, if behind the meter systems displace generation from utility-scale solar, there is an additional societal benefit of avoiding land use. Alternatively, if the behind the meter systems displace natural gas generation, there are no avoided land benefits but there are benefits of avoiding air pollution and water usage.

Table 2. NEM 2.0 Lookback Study, Weighted Average Benefit Cost Ratios

	Technology	Participant Cost Test	Ratepayer Impact Measure
PG&E	Solar PV	1.82	0.33
	Solar PV + Storage	1.52	0.38
SCE	Solar PV	1.56	0.48
	Solar PV + Storage	1.39	0.56
SDG&E	Solar PV	2.09	0.31
	Solar PV + Storage	1.55	0.39

As a separate indication of the discrepancy between NEM compensation and the value customer-sited renewable generation provides to the electric system, Table 3 presents a comparison from the illustrative analysis conducted to support this white paper. The table compares the average bill savings provided under the NEM 2.0 program, per kWh of solar generated, and the average system avoided cost value of this generation using the 2020 avoided cost values adopted in R.14-10-003.[17]

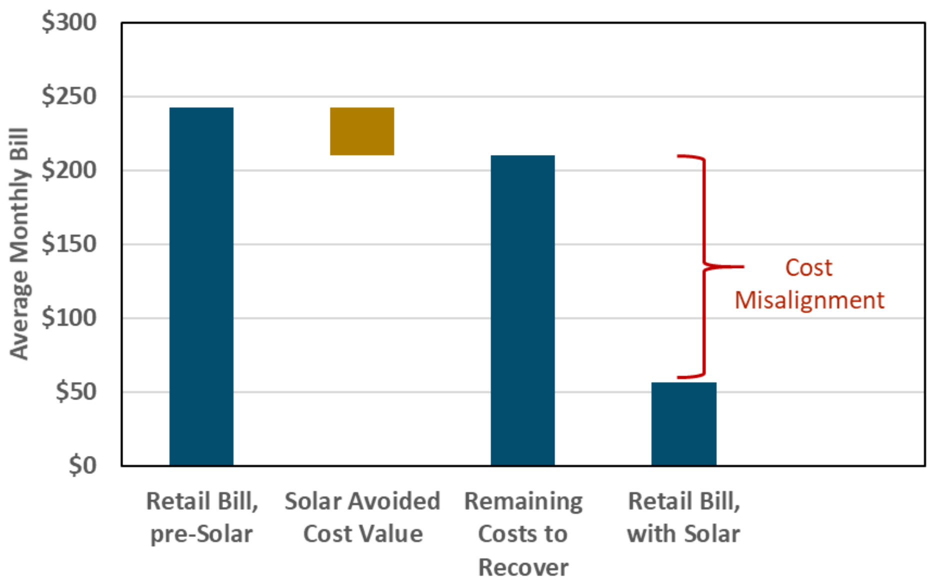
Table 3. Solar Customer Bill Reductions and System Avoided Cost Value Under, NEM 2.0

Value	$/kWh solar
Average Solar Compensation Paid to Customers	$0.312
System Avoided Costs	$0.055
Delta	$0.258

Figure 5 below illustrates the magnitude of the average monthly bill for the average customer from a sample of load shapes prior to installing solar (left column), as well as the total system avoided cost value provided by a solar system sized to offset 80 percent of annual load (second column). The third column depicts the remaining costs to be recovered, after accounting for the solar generation's avoided cost value, while the fourth and final column provides the average monthly bill for the average customer after the installation of the solar system. As shown by the red bracket, the difference between the third and fourth columns represents the misalignment in costs between the bill savings available to NEM customers/developers and the value their system provides to the electric grid.

[17] Analysis uses a sample of residential load and solar generation profiles from the *NEM 2.0 Lookback Study*. Additional detail on the analysis conducted, including underlying assumptions, is provided in Section 6. Note that the difference between the benefit cost ratios shown in the Lookback Study table (Table 2) and the implied benefit cost ratio shown in Table 3 is due to the former both including residential and nonresidential systems and being based on a 25-year NPV, whereas the illustrative analysis from which the results in Table 3 derive includes only residential systems and is based on a single-year snapshot of 2020 retail rates and avoided costs.

Figure 5. Average Residential Customer Annual Bill (With and Without Solar), and Remaining Non-Avoidable Costs After Accounting for Solar Value



The low benefit to cost ratios found in the *Net-Energy Metering 2.0 Lookback Study,* as well as the per-kWh comparison shown above in Table 3 and the remaining non-avoidable costs to recover illustrated in Figure 5 highlight the substantial misalignment between costs and value under the current compensation structure. This results in an increase in costs to be recovered from nonparticipating customers.

3. Elements of the Proposed Reform Framework

Objectives

A primary objective of this framework is balancing the need to recover the residual unavoidable costs from customer-generators through proper rate design (and billing mechanisms) and providing sufficient bill savings to prospective customer-generators for continued sustainability of the customer-sited renewable generation industry. Other objectives that we considered in proposing a compensation framework that will serve as a successor to the current NEM tariff include:

+ Progressing towards the use of more advanced rate designs and the benefits these designs offer, considering the possibility that any new rates implemented in this case could eventually serve as the basis for compensating all distributed energy resources (DERs), including unlocking the full value of battery storage as well as end-use and building electrification.
+ Balance between oftentimes competing objectives. Rates need to be designed to collect authorized revenues, but also must encourage efficient consumption and investment decisions. Additionally, ensuring the transparency of any targeted support mechanism to DERs is also key, so that customer-generators and developers are aware of any anticipated changes to the compensation mechanism. Aligning retail rates and customer-sited renewable generation

compensation with underlying grid costs promotes both equitable valuation of distributed resources and efficient consumption of electricity.

The successor rate also must consider other goals as outlined in Table 4.

Table 4. Best-Practice Ratemaking Objectives

Principle	Objectives
Efficiency	• Encourage economically efficient consumption and investment decisions that lead to overall lowest system costs. • Preserve cost-causation principles that consider marginal or avoided costs. • Encourage efficient levels of conservation, energy efficiency and demand reduction, especially when most valuable for the grid.
Transparency and Predictability	• Design rates that are understandable and allow for bill predictability. • Educate customers about rate choices.
Equity	• Avoid unfair allocation of embedded costs and rate misalignment . • Make any compensation above avoided costs explicit and directly supportive of legislation or state policy goals, such as low-income customer support.
Cost recovery	• Design rates that provide a reasonable opportunity to the utility to recover its authorized revenue requirement.

The remainder of this section provides a high-level overview of how the proposed compensation framework attempts to meet those objectives.

Disconnecting Value of Solar from Retail Rate

There are a variety of strongly held opinions regarding the ideal approach to be taken to resolve the cost misalignment inherent to NEM compensation for customer-sited renewable generation. Many jurisdictions have had extensive proceedings and while the solutions vary, the common element is that a gradual move towards cost alignment is needed to mitigate unacceptable bill impacts. It is easier to make more effective progress on cost and rate alignment if customer-generators are billed on a separately designed rate exclusive to customers with onsite renewable generation. In the rate examples we develop below we have assumed that the CPUC has authorized:

1. Replacement of the current NEM 2.0 solar compensation with a method that is separate from the retail rate.
2. Utilities to begin reforming the rate design for customer-generators as described by each of our examples that more closely align bill reductions with avoided costs.

3. Adoption of a market transition credit (MTC) to provide the additional financial return to customers required to maintain a viable customer-sited renewable generation industry, after accounting for bill savings and the newly adopted rate for exports to the grid. The “glide path” rate examples we develop in Section 7 demonstrate that a MTC would allow the utilities to develop a proposed rate and cost alignment transition plan with the CPUC estimating the level of the required MTC if and when it might be needed.

While mandatory for participating NEM customers, the successor tariff can be optional for any customer with a DER, as the volumetric charges are reduced towards the avoided cost of electricity, eventually making it a truly technology-neutral rate. While this is certainly a laudable goal, it makes the choice of a suitable transitional structure more challenging. In Section 6 we explore rate design alternatives that would enhance equity by more rigorously incorporating cost causation principles. We show it would be very difficult to make a fully cost reflective economically efficient tariff the default residential rate, since fundamental rate revisions focused on cost-causation call for a substantial increase in fixed charges, among other alternatives, to reduce the reliance on volumetric charges for fixed cost recovery. Thus, it is necessary to move gradually towards this alignment and potentially use an external support mechanism to satisfy competing legislative goals.

As part of the proposed framework, we propose that the excess generation not consumed onsite be valued at system, time-differentiated avoided costs, i.e., using a “net billing” approach with exports compensated at avoided costs. Net billing provides different compensation to participating customers depending on whether they consume or export the output of their BTM system. The export price is generally set at avoided costs, and therefore may be less than the full retail rate customers pay to their load serving entity for grid consumption. This is distinct from NEM, which provides bill credits at the retail rate for generation exported to the grid.

Netting is the billing process used to determine when a customers is selling back to the grid and can occur on an hourly, TOU period, monthly, or annual level. Hourly netting provides more opportunities to price BTM solar output at its electricity system value, while annual netting typically exposes many fewer hours to non-retail rate compensation. The primary benefit of net billing is that allowing compensation of exports to be disassociated with the retail rate provides a more objective and transparent method, unaffected by the structure of the retail rate. Moving away from net metering and towards net billing is considered a “middle ground” approach among alternatives. Participating customers retain the ability to earn bill savings at the full retail rate for the remaining solar output which is consumed onsite. All else equal, net billing represents an improvement in economic efficiency compared to classic NEM. Setting an export rate based on estimated avoided costs has been increasingly used in many jurisdictions across the country, although the method to set avoided costs varies. In some jurisdictions, like New York, discussions have considered if export rates ought to include a non-monetized, societal avoided cost component to support the BTM solar industry. However, including non-monetized values is not necessary if using targeted transitional support elements, such as the MTC described below.

In all of our rate examples we chose to use net billing because it is more moderate than other alternatives such as “buy all, sell all” structures where the entire customer-generator output is priced at whatever value is deemed appropriate based on economic and/or policy considerations. Also, under buy all, sell all structures the customer must pay for their gross usage at the retail price, and therefore generation that is consumed onsite is valued at the difference between the retail tariff and the sales price. Use of this approach in California would represent a significant and sudden change in the value proposition to customer-generators, but should not be excluded from the list of potential longer term rate design alternatives.

4. Proposed Role of the Market Transition Credit

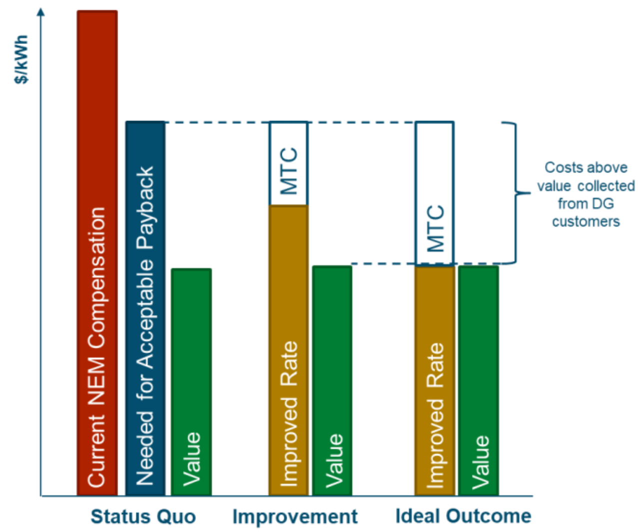
What is the MTC?

In the framework we use, the market transition credit is needed to enable the transition of NEM customers towards a more fully cost-reflective rate, by making up the gap between the estimated acceptable payback amount and the transitional rates that will more closely align rates with avoided costs. Without a mechanism of this type combined with the ability to offer a NEM specific rate design, the rate transition becomes constrained by both the legislative sustainability requirements and the effort to mitigate billing impacts. The MTC structure also provides certainty for developers of customer-sited renewable generation systems by providing a clear and transparent value to plan around, including the timing of when this credit would be adjusted for later vintages. The MTC can be calibrated for different geographic, income-based, or other populations depending on policy goals, providing flexibility in determining the appropriate compensation to be awarded to different groups of customers with onsite renewable generation. Finally, this mechanism allows for direct cost tracking for future collection.

In our application, the MTC is focused on BTM solar and is structured as a $/kWh credit applied to all generation. We design the MTC to provide a reasonable return on investment for the average customer-generator, considering the customer's investment, the bill savings provided, and the remaining savings required to meet a desired payback period. The payback period is selected as a reasonable amount of time for a customer's investment to pay for itself. If the costs of BTM solar continue to decline, a declining MTC would allow for a gradual process or "glide path" for reducing the additional financial support provided to make such investments viable.

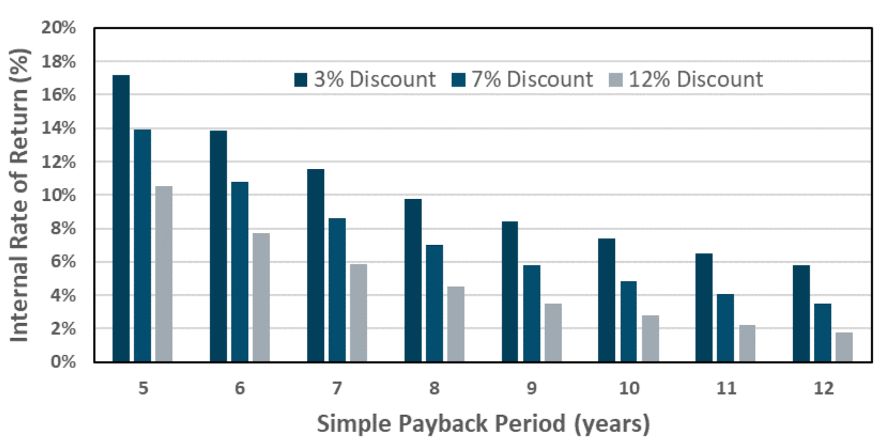
Figure 6 below provides an illustration of how the MTC can bridge the gap needed by customer-generators to earn a viable return on their investment after adopting an improved retail rate ("improvement") that preserves some cost shifting, and a fully cost-reflective rate ("ideal outcome"). The columns on the left-hand side of the figure ("status quo") compare the per-kWh bill reductions that customer-generators receive under the current NEM 2.0 program (tallest column, red), the amount needed to provide an acceptable payback (middle column, blue), and the value provided to the electricity system. (shortest column, green). The bill reduction provided by an improved multipart rate (gold "improved rate" column), would be more consistent with avoided system value than the current bill reduction, but short of the amount necessary to provide an acceptable payback for the solar customer. The MTC would provide the additional revenue required by the solar customer to meet a reasonable payback period. Under an ideal full cost-based rate (gold "ideal outcome" column), the MTC required to bridge the gap would be larger.

Figure 6. Role of Market Transition Credit in Payback Period



It is reasonable to expect that different groups and classes of customers might need different payback periods to consider an investment acceptable. A simple comparison of the internal rate of return (IRR) implied by various discount rates demonstrates the range of potential annual returns at different payback periods, as shown in Figure 7 below. The tallest column in each grouping represents the implied IRR for the simple payback period (x-axis) at a three percent discount rate, while the middle and shortest columns represent the implied IRR at seven and twelve percent discount rates, respectively. Such a comparison may be useful in determining to what payback period the MTC might be calibrated for different groups.

Figure 7. Implied Internal Rate of Return (IRR) by Simple Payback Period and Discount Rate.



Funding Options

A key implementation decision with regard to a MTC is how the tracked cost misalignment – referred to here as the MTC recovery surcharge – could be funded to comply with AB 327. There are several ways to recover tracked costs in a manner that avoids cost shifting from participating customer-generators to nonparticipants. Different approaches would collect MTC costs either from:

a) the *same* vintage of participating customers who benefit from the MTC, but after the customer has paid off their system;
b) future vintages of DER customers;
c) all customer-generators enrolled in the mandatory rate (regardless of vintage),
d) all customers as a socialized expense.

The first approach acts as a loan to the customer that assures full payback for the customer's investment, with those upfront discounts paid back to the utility over a defined period of time after the credit expires. This approach minimizes cost shifting, but might also limit customer adoption, particularly for customers with ready access to capital and relatively low discount rates.

Allocation of MTC costs to future vintages of participating customer-generators solves the potential adoption problem highlighted in the first option but has the potential to increase the MTC recovery surcharge up to unsustainably high future levels where it cannot be easily collected from even large groups of applicable customers. If this approach is used, it should be implemented with clearly defined caps on the amount of charge or deferred total revenues allowed in the tracking account.

The MTC recovery surcharge could also potentially be collected through a separate charge on all participating customer-generators once their respective vintaged payback periods end. This is distinct from the previous two options, which alternatively would collect MTC costs from either: (a) the vintage that incurred those costs, or (b) specific future vintages of customers. This approach could be implemented using a 2-to-3-year window where rates and the MTC were fixed for a defined future window for all customers who signed up for the rate and received a MTC during that window. This approach also would have some negative impact on customer adoption. The window could be defined by either time, number of participants, or total MW capacity subscribed. If implemented under a long-term gradual plan to rationalize rates for customer-generators, there would be a subsequent offering with a distinct, lower MTC value.

Finally, if the transition period and the amount of the total compensation above avoided costs were capped at some acceptable levels, the CPUC could determine that the overall long-term costs of the MTC were a reasonable amount to pay for all customers to transition to longer term sustainable rate structures. This cost socialization is likely to only be viable if the gap between the bill savings required for a viable payback period and the system avoided cost value narrows fairly quickly. If it does not narrow sufficiently this would result in a sizeable MTC funding requirement being passed on to nonparticipating customers, which would not be acceptable under the directives of AB 327.

5. Alternative Rate Designs

Common Design Elements of Cost-Reflective Rates

As stated in section 3, assuming other design goals are being met, rates should be designed to provide customers with efficient price signals as they decide whether to use more energy, or engage in energy efficiency, or adopt a particular DER technology. This overarching principle requires considering the following two steps:

1. Move volumetric rate components gradually towards the **underlying marginal of energy and capacity costs** by time of day period. These marginal cost estimates are regularly developed by the three California IOUs as part of the general rate cases.
2. Undertake **revenue reconciliation** to make sure that the rate is developed to recover the class revenue target, based on forecasted billing determinants, but keeping in mind customer's reaction to changes in energy versus fixed charges, and marginal cost considerations. The California IOUs set the class revenue targets using "Equi-Proportional Marginal Cost" (EPMC) allocations as a starting point, modified as necessary for gradualism and other policy considerations.[18]

The remainder of this section summarizes examples of rates that can be designed using marginal cost information and the two steps above, to bring the avoided costs and customer-sited renewable generation compensation into alignment. In determining the most appropriate successor rate for California, it is essential to consider that any decision on alternative rates for customer-generators must meet the same objectives that would apply to all other rates, as outlined in Section 3. There is no one-size-fits-all solution for rate design, given the need to accommodate the various competing objectives in each case.

The proposed rate examples are by no means exhaustive of all the rate mechanisms available that would increase alignment of avoided costs and rates. The focus of this white paper is to discuss relatively simple rate design options, using the average customer in the residential class to set revenue-neutral rate examples using some of the elements of rate design discussed here, for illustration and comparison with current retail rates.[19]

Rate Design Alternatives

TOU Demand Charges

In addition to a fixed charge and energy charges, rates may include time-of-use demand charges that are assessed on the customer's net maximum demand (typically measured in either 15-minute or 30-minute intervals) within the on-peak and perhaps mid-peak period. Time-differentiated demand charges are useful to signal the higher marginal cost of meeting an increment of kW in the hours with highest electricity cost to serve the net demand. Depending on design, TOU demand charges can help potentially alleviate grid constraints, particularly when combined with an automated form of demand response, both on the larger bulk power electric grid and on the distribution system. Passing this time-variation in capacity value of load reductions through to retail rates can therefore increase economic efficiency in cost collection.

[18] EPMC represents a simplification of the "Inverse Elasticity Rule" derived by Frank Ramsey in its publication "A Contribution to the Theory of Taxation". The Economic Journal, 37 (145), 1927. Ramsey found that to maximize efficiency, monopoly rates for different customer groups must include a mark-up over marginal cost in a manner inversely proportional to each group's elasticity of demand. EPMC essentially assumes all customer groups have the same elasticity of demand. See also Baumol, W. J. and Bradford, D. F. " Optimal Departures from Marginal Cost Pricing", American Economic Review 60:265–283. June 1970.

[19] Individual customer bills are unlikely to be identical under an existing rate and an alternative rate that is based on class revenue neutrality (some customers' bills on the new rate will increase, while other customers' bills will decrease).

Demand charges provide another source of revenues that is distinct from energy charges and can be used to increase alignment of rates and avoided costs. They also increase the value proposition of both demand response and energy storage. Customers will derive value by investing in demand-limiting devices or BTM storage, particularly if paired with solar so that stored solar energy may be applied to shave demand during the on-peak hours. Demand charges defined for a few peak hours tend to be easier to avoid with battery storage.

A common argument against demand charges is that they may be overly punitive for residential and small commercial customers, who, despite being educated about demand charges, may have occasional load spikes in a given month that tend to be sufficiently small to avoid driving new capacity related investments. To mitigate this perceived concern, utilities may adopt non-traditional demand charge forms, such as demand charges assessed on an average of several maximum demand hours during a time period. In this form, the demand charges become very similar to super peak period energy charges. Another variation of demand charge is daily on-peak demand charges, more typically seen in the context of standby rates but also potentially useful for optional residential rates in the context of DERs.[20] Such charges reduce the impact on customer bills in days where they need to rely on the utility to meet on-peak electricity needs as compared to maximum monthly demand charges, and therefore are more attractive to customers.

Grid Access Charge

A rate component such as a grid access charge (GAC) is a fixed monthly charge that can collect the remaining fixed costs which are not recovered through more traditional fixed charges, shifting fixed cost recovery away from energy and demand charges. The GAC may be set to recover, as a minimum, a portion of local distribution facilities costs. Uses of GACs in the context of NEM typically employ a monthly fixed fee per kW of nameplate solar capacity to recover the non-avoidable costs of service. The GAC can also be based on contract demand using either a customer-specific maximum kW nominated by the customer (see Subscription Rate below) or based on the annual maximum customer non-coincident peak demand.

Dynamic Rates

In addition to the more traditional time-of-use rates with pre-determined periods and rate levels, dynamic, time-variant options deserve consideration given the potential for better alignment with critical peak conditions on the grid. Flexible dynamic energy pricing (such as Critical Peak Pricing, or CPP) has the ability to efficiently ration system capacity when it is needed as compared to regular TOU peak energy or demand charges. The critical events are typically communicated to the customer the day before, based on high likelihood of system-wide and/or locational grid constraints, and trigger a predetermined higher on-peak price for those days, which is generally several times higher than the regular on-peak charge. A CPP rate attempts to target the hours with highest reliability risk in the year and most CPP rate designs target between 12 to 18 critical event days in the peak season. Customers who reduce load in those hours can lower their bills while benefiting the system.

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[20] In New York, utilities offer standby rates for partial-requirement commercial customers with onsite generation include daily demand charges. A few utilities like Salt River Project in Arizona offer optional TOU rates with residential daily on-peak demand charges.

A more dynamic rate is Real Time Pricing (RTP). These rates are generally set as a two-part rate structures, with energy prices that change hourly with day-ahead or real-time market prices. They may also include a scarcity price component in certain critical hours. These dynamic rates have been adopted in California by the IOUs, mostly targeting commercial customers.

Subscription Rate Models

A rate structure that is worth considering involves allowing customers to subscribe to a service level. Under the traditional simple version of a subscription rate model, customers usually pay a fixed monthly bill based on their subscription service level (e.g., maximum kW) and all energy consumed is paid at rates reflective of avoided energy costs. Consumption above a customer's subscription may be provided if available at market-based rates. The subscription-based charge is typically structured to recover most of the costs of service associated with the subscription level except for marginal energy costs which may be recovered in separate charges. Applications of this rate may use a default subscription level equal to some definition of customer's maximum historical demand if the customer cannot make that determination.

The customer monthly subscription charge may apply to customer's annual (or longer) maximum non-coincident load, or in combination with customer's on-peak demand. This structure has the advantage of allowing the customer to monetize long-term investments in more energy efficient appliances or in battery storage, if those investments truly offset grid costs and cost-based subscription fees. At the same time, the subscription fee may be re-set at a higher level when customers' usage exceeds a certain kW threshold, to keep the cost recovery from these customers aligned with their contribution to cost of service over time.

Subscription rates allow for recovery of a larger share of costs of service on a fixed basis, leading to lower energy charges. PG&E implemented subscription-based charges in its Commercial Business Electric Vehicle Rate (BEV), effective in May 2020. Pilots using the subscription rate concept for residential customers are currently in place in New York and have been proposed in Arizona, to gauge the level of customer interest, as well as to demonstrate the benefits from adopting them along with smart devices.

6. Illustrative Fully Cost-Based Rates and Impacts

To support the discussion in this paper, E3 developed various illustrative rates reflecting a higher fixed charge and different combinations of the design components described in the previous section. For purposes of developing these rates, we assume that the successor rate produces the same revenue as the residential (default) rate class. That is, all rate options contemplated were set so that the customer bill under the new rate would be equal to what the customer would pay under the otherwise applicable rate customer, assuming a load profile equal to the residential average class load shape (i.e., prior to considering any changes in load from solar generation) would pay the same bill under the rate alternative.[21]

[21] The computation of the residential class average load shape was based on the average of a sample of residential customer hourly load shapes in SDG&E territory. E3 obtained a subset of average customer load profiles from SDG&E service territory, segmented into bins by climate zone, gross annual energy consumption, service type (all electric vs. dual fuel), and presence or absence of an electric vehicle at the premises. This dataset was developed by Verdant Associates from anonymized, individual customer load profiles for use in the NEM 2.0 Lookback Study.

As the starting point, the kWh charges in all illustrative rates considered were set at the avoided (marginal) cost estimates by time of day and season. These avoided costs were developed according to the methodology established for the CPUC 2020 Avoided Cost Calculator.[22] Under all alternative rates we assumed a "net billing" design, where the netting occurs on a monthly TOU period basis, and any excess energy is credited at rates equal to avoided costs.[23]

Alternative Rate Designs Assuming Full Mitigation of Cost Misalignment

Table 6 compares the existing residential rate with the resulting illustrative rate levels under alternative multi-part designs that would immediately close the gap between utility benefits from solar (avoided costs) and solar customer bill reductions. Each of these designs were set to collect the same (pre-solar) revenue for the class average load shape, net of non-bypassable charges. The illustrative rates were set to be revenue neutral to the current SDG&E TOU-DR-1 rate. The "Current Residential" design shows the current energy charges from SDG&E's TOU-DR-1 residential rate (excluding non-bypassable charges), as well as the monthly equivalent of the minimum bill included in that rate.

+ **The "Two-Part" Marginal Cost (MC) rate** sets energy charges at the marginal unit cost ($/kWh) for each TOU period. These energy charges are substantially below the energy charges in the existing residential rate, about 40 percent lower in the summer on-peak period and 80 percent lower in the winter on-peak period, in alignment with the seasonal difference in marginal costs. The monthly charge would have to be increased dramatically from current residential rates, to about $177/month to make this rate produce the same revenues produced by the existing rate. This customer charge level is certainly beyond a reasonable range for even the very large residential energy consumers. The exercise is useful to illustrate the very high levels of fixed charge needed for California residential rates when the per-kWh charges are set at marginal (or avoided) unit costs.

+ **The "Multi-Part Grid" option** also sets energy charges at TOU marginal cost values, as in the Two-Part rate, but incorporates a GAC of about $24/kW-month that allows for a more modest increase to the customer charge as compared to the current residential monthly charge. The GAC component of the bill does not change from month to month since for this rate example it is applied to the customer's annual maximum demand. The maximum demand of a residential BTM customer-generator is typically in the 5-7 kW range. The GAC could take several alternative forms, including a charge assessed on a specific contract maximum demand level selected by the customer. In this rate, the GAC and the fixed charge recover the non-avoidable costs of the customer with BTM generation.

+ Under **the "Multi-Part Demand" option** the rate includes TOU demand charges for the summer season. For purposes of this illustrative rate, all TOU energy charges have been set at the TOU

[22] Refer to Figure 4. 2020 Hourly Average Avoided Costs and Solar Generation, Annual Averages in Section 2 for the breakdown of marginal costs that vary with energy and demand.

marginal cost values as in the other rates in the table.[24] The summer demand charges were calibrated to meet the revenue-neutral condition assuming a monthly customer charge of $50/month. These illustrative high demand charges ($40/kW in the on-peak period, and $25/kW in the mid-peak period) would create unacceptable bill impacts for residential customers with high air conditioning-driven summer peak loads. There are also customers who may not benefit from the much lower winter TOU prices in this rate (e.g., those with gas heating and relatively lower winter electricity usage).

Table 5. Illustrative Fully Cost-Based Successor Rates

	Current Residential	Two-Part MC	Multi-Part "Grid"	Multi-Part "Demand"
Customer Charge ($/month)	$10.28	$177.18	$40.00	$50.00
Grid Access Charge ($/contract kW/month)	N/A	N/A	$24.40/kW	N/A
On-Peak Summer Demand Charge ($/kW/month)	N/A	N/A	N/A	$40.00/kW
Mid-Peak Summer Demand Charge ($/kW/month)	N/A	N/A	N/A	$25.00/kW
Energy Charge ($/kWh)				
Summer On-Peak	$0.478	$0.288	$0.288	$0.288
Summer Mid-Peak	$0.281	$0.117	$0.117	$0.117
Summer Off-Peak	$0.235	$0.050	$0.050	$0.050
Winter On-Peak	$0.332	$0.069	$0.069	$0.069
Winter Mid-Peak	$0.324	$0.054	$0.054	$0.054
Winter Off-Peak	$0.314	$0.046	$0.046	$0.046

While these illustrative rate alternatives provide examples of economically efficient multi-part rates, they do not reflect other rate design principles and would substantially reduce the attractiveness of investing in BTM generation, potentially making it challenging to maintain a viable customer-sited renewable generation industry in the state. A strict application of an optimized residential rate structure may cause unacceptable impacts to a subset of customers, including low-usage customers and customers currently under NEM. Table 6 below illustrates the difference in modeled annual average bill savings between the

[24] When implemented, the on-peak and mid-peak summer kWh charges would be reduced by the marginal capacity costs since those costs would be implicitly part of the demand charge.

cost-based options, as well as their relation to the annual average avoided cost value from the 2020 Avoided Cost Calculator, all stated in $ per kWh of solar generation.

Table 6. Bill Reductions and System Avoided Cost Value

$/kWh solar	Current Residential	Two-Part MC	Multi-Part Grid	Multi-Part Demand
Bill Reductions	$0.312	$0.087	$0.117	$0.103
System Avoided Costs	$0.055	$0.055	$0.055	$0.055
Delta	$0.258	$0.033	$0.063	$0.048

Each of the cost-based alternative rate designs aligns bill savings value much more closely with avoided costs than the current residential rate by setting energy charges (for both consumption and net exports) at the avoided cost value and collecting fixed costs separately. There are several conclusions that we draw from these simple alternative designs:

+ Efficient forms of multi-part rate designs cannot be implemented quickly without causing unacceptable billing impacts to existing NEM customers and most likely damage to the market for customer-sited renewable generation in California.
+ However, as the costs of customer-sited renewable generation decrease over time, helped by recent extensions of federal tax credits, it might be possible to gradually increase fixed charges for all customers and reduce the energy components of the rate closer to their respective marginal costs.
+ The bill reductions captured by customer-generators are very large. Our simple example above illustrates that under the current rate solar customers receive in excess of 31 cents per kWh produced. This is more than sufficient compensation, and we will show in the following section that this produces a very short payback period of 4.1 years.[25]
+ The progression to more efficient rate designs that also align value with bill reductions from BTM generation could be accomplished even faster if California were to explicitly design rates to provide a defined payback period for the average customer.

Bill Impacts for Building Electrification

For a successor tariff that is available to all customers an additional consideration is how it will impact adoption of other DERs, not just BTM solar. Here we provide bill impacts for the same illustrative rate alternatives outlined above for a building electrification example, as electrifying building end-uses is a key

[25] For participant costs these calculations assume NREL's "Moderate" CapEx and OpEx projections from the 2020 Annual Technology Baseline (ATB), of $2,644/kW and $19.83/kW-yr (in 2018 $), respectively, as well as a 26 percent ITC. A 7.0 percent real discount rate is used for the LCOE calculation. The $0.31/kWh bill reduction is based on the class average load shape and average solar shape, and a solar system sized to offset 80 percent of gross annual consumption. Bill savings were calculated using the current SDG&E TOU-DR-1 rate.

pillar of California's decarbonization strategy. A successor tariff should attempt to align customer incentives for bill savings with benefits to the grid and advancement of California's GHG goals.

For the building electrification example, we use inland residential load shapes for both a mid-sized dual fuel and a mid-sized all-electric home. Under current residential rates, an all-electric home will have a bill that is $69 per month higher than a comparable dual fuel home (not including natural gas bill savings).

Table 7 below shows the estimated electric bill impacts of building electrification and customer-sited renewable generation solar under existing rates and all three of the alternative rates. The Two-part MC rate structure we describe above improves the economics for electrification substantially, with a much smaller increase in electric bill for the all-electric home of only $14 per month. Under the Multi-part Grid rate, the monthly bill increase from electrification is $29 per month. Under the Multi-Part Demand rate the all-electric home bill is actually lower. This is because more efficient air conditioning reduces on-peak load and most of the increased electric load for heating occurs in the mid- and off-peak periods. Note that this simple calculation ignores any savings for the reduced costs of other fuels.

Table 7. Illustrative Monthly Bill Impacts of Building Electrification and BTM Solar

Monthly Bill	Current Residential	Two-Part MC	Multi-Part Grid	Multi-Part Demand
Effect of Electrification on Monthly Electric Bill	$69	$14	$29	($8)
Solar Monthly Bill Savings	($128)	($27)	($29)	($41)

Examples of Market Transition Credits

As described in Section 4, a market transition credit can be used to augment the savings provided to customer-generators through retail rates in order to adjust the estimated payback periods for new vintages of customer-generators as we gradually align rates with costs. In this section we discuss how the MTC could be incorporated into the illustrative rates outlined in the preceding section.

Table 8 presents the average $/kWh savings in bill reductions that BTM solar customers receive under the existing SDG&E example tariff (as modeled for this illustrative analysis) and under the three higher fixed charge rate alternatives, as well as the implied simple payback period based on current solar cost data from the National Renewable Energy Laboratory.[26] Simple payback periods and incremental $/kWh MTC values are shown inclusive of the current 26 percent federal investment tax credit (ITC).

[26] Data from NREL 2020 Annual Technology Baseline. Available at: https://atb.nrel.gov/electricity/2020/.

Table 8. Bill Reductions and MTC Required for Different Payback Periods

$/kWh Solar	Current Residential	Two-Part MC	Multi-Part-Grid	Multi-Part-Demand
Bill Reduction	$0.312	$0.087	$0.117	$0.103
Simple Payback	4.1 yrs.	14.8 yrs.	11.0 yrs.	12.6 yrs.
MTC, 5-yr Payback	N/A	$0.172	$0.141	$0.156
MTC, 7.5-yr Payback	N/A	$0.085	$0.055	$0.070
MTC, 10-yr Payback	N/A	$0.042	$0.012	$0.026
MTC, 12.5-yr Payback	N/A	$0.016	N/A	$0.001

Due to the large $/kWh value provided to solar customers under the current residential rate, the payback period is relatively short at 4.1 years.[27] Alternatively, the other illustrative, cost-based rates – which provide considerably lower value to solar customers – provide a considerably longer payback period, which may be beyond the acceptable range of investment returns that the majority of potential customers would accept.

The lower portion of Table 10 also shows the incremental $/kWh value which would be required under each illustrative rate in order to provide a payback period of 5, 7.5, 10, or 12.5 years. Note that given the payback period under the current residential rate is 4.1 years, there is no need, except in the 5-yr payback case, for a MTC to create paybacks equal to or shorter than these levels. This highlights that customers currently receive greater savings from solar under NEM 2.0 than would be required for these levels of return on their investment.

7. Glide Paths for Transitional Successor Rates and MTC

We have established that a MTC might be a useful ratemaking tool bridging the gap between a desired payback period for customer-generators and more efficient rates. We have also shown that we need a robust ratemaking framework that can be easily tracked and adjusted to guide a gradual transition and to provide a reasonable return on investment as directed by AB 327. In this section, we assumed two "glide paths" with a new set of illustrative rates that are gradually improved and modified over a ten-year period to better reflect underlying variation in costs through TOU kWh charges, with a MTC applied as needed.

Transitional Illustrative Rates

Table 9 presents several illustrative rate designs that could be used sequentially (starting with design A and ending with design C) during the transitional period to progress gradually towards efficient reflection of underlying system costs. As with the rates described in the previous section, these designs are structured to be revenue neutral for the class average load shape prior to the installation of BTM generation. However,

[27] Note that not all payments for behind the meter generation flow directly to end use customers. The payment enabled by NEM is shared between panel and equipment manufacturers, developers/installers, and customers.

in contrast to the bookend rate alternatives shown earlier, these rates are not strictly cost-based as they are intended as transitional designs which can help to bridge the current rates and future cost-based rates. These transitional rates are not intended to represent recommended specific price levels but rather a structure that would facilitate transition while still aligning costs more closely with efficient price signals.

These transitional rates include progressively larger fixed charges from design A to design C and, accordingly, recovery of a larger share of fixed costs through the fixed customer charge, the GAC, and the on-peak demand charges. TOU energy charges are set to collect the necessary remaining uncollected revenue to meet revenue neutrality. For illustrative purposes, all TOU energy charges for net consumption are structured to maintain the ratios of underlying marginal per-kWh avoided energy costs between different periods and between seasons. As a result, all kWh prices are lower than the current rates. As with the cost-based rates discussed previously, export rates are set to avoided electricity costs and we have assumed that the netting occurs by month and by TOU period. The "Current Residential" rate is included in this table, for comparison, as are marginal per-kWh costs (both total marginal costs, to which export rates are set, and energy only marginal costs) in the rightmost columns.

Table 9. Illustrative Transitional Successor Rates

	Current Residential	A	B	C	Marginal Costs (All)	Marginal Costs (Energy)
Customer Charge ($/month)[28]	$10.28	$50.00	$60.00	$70.00		
Grid Access Charge ($/contract kW/month)	N/A	$5.00/kW	$6.00/kW	$7.00/kW		
On-Peak Summer Demand Charge ($/kW/month)	N/A	$10.00/kW	$15.00/kW	$20.00/kW		
Energy Charge ($/kWh)[29]						
Summer On-Peak	$0.478	$0.320	$0.266	$0.212	$0.288	$0.050
Summer Mid-Peak	$0.281	$0.222	$0.185	$0.147	$0.117	$0.035
Summer Off-Peak	$0.235	$0.161	$0.134	$0.106	$0.050	$0.025
Winter On-Peak	$0.332	$0.231	$0.192	$0.153	$0.069	$0.036
Winter Mid-Peak	$0.324	$0.173	$0.143	$0.114	$0.054	$0.027
Winter Off-Peak	$0.314	$0.147	$0.122	$0.097	$0.046	$0.023

[28] The customer charge of $10.28/month shown for the current residential rate is a proxy for the minimum bill included in SDG&E TOU-DR-1 ($0.338/day).

[29] Energy charges shown net of nonbypassable charges, which are assessed under all rate options.

MTC Under Various Scenarios

Glide Path 1: Optimistic Scenario

The first illustrative glide path depicts a relatively optimistic scenario which assumes that BTM solar technology costs decline sufficiently throughout the coming decade that customer-generators are able to meet a 7.5-year payback period without an incremental MTC. Specifically, this scenario assumes that in conjunction with the federal ITC expiring after 2023, installed costs for BTM solar decline from current levels by 5 percent per year.

Figure 8 depicts how the rate transition might look under this scenario. Due to the optimistic assumptions on technology costs, relatively lower $/kWh savings are required to meet an example 7.5-year payback, as shown by the gradually decreasing, solid green line. This level of required savings is a direct function of the assumed technology costs and specified payback period. As a comparison, the dotted red line indicates the avoided cost value provided by BTM systems, assumed here to increase modestly throughout the decade at an annual rate of three percent. This modest annual increase is based roughly on average annual bundled system average rate increases in recent years.

The dark blue columns illustrate the average $/kWh bill reductions solar customers receive under the different vintages of rates outlined in Table 9 on the previous page. This example shows a transition through the three illustrative rate designs over the decade, with progressively lower solar customer savings as the retail rates with increasing fixed, grid access and/or demand charges are sequenced in. However, as technology costs are assumed to decline over the same period in this scenario, solar customer bill reductions remain at or above the required level to provide a 7.5-year payback, negating the need for an incremental MTC.

Figure 8. Bill Reductions and MTC, Optimistic Scenario

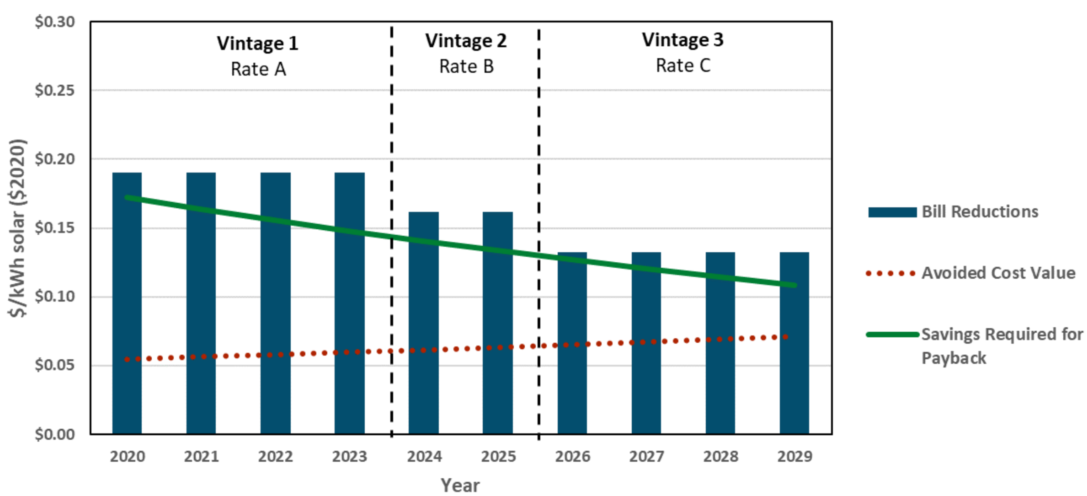
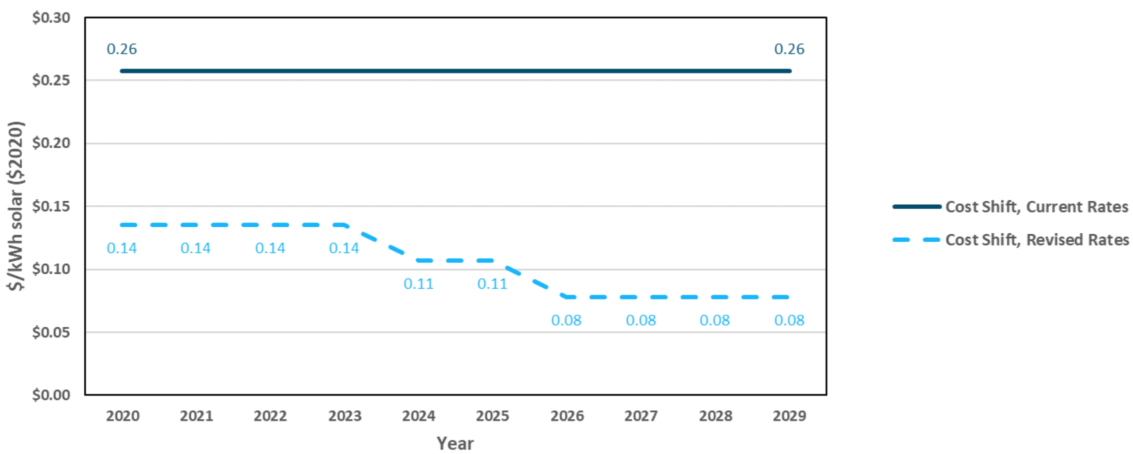


Figure 9 provides a comparison of the $/kWh cost shift in the current residential rates (as calculated in our illustrative analysis) of $0.26/kWh, and the remaining cost shifts in the different vintages of transitional rates. By the end of the decade there is a large difference between these two values, as the transitional rates have gradually reduced cost shifting by increasing fixed charges. Note that decreasing the cost shift without the use of a MTC is largely enabled by the assumed decline in technology costs.

Figure 9. Cost Shift Comparison, Optimistic Scenario



To put these figures into context, assume that 500 MW of BTM solar are installed in 2029, with an average annual output of 1,700 MWh/MW of installed capacity. Using the modeled cost shift under current residential rates ($0.26/kWh) this would equate to a total incremental shift of approximately $219 million in that year. Using the modeled cost shift under the revised rate in place in 2029 ($0.08/kWh) this would equate to approximately $66 million, or a reduction relative to current rates of $153 million.[30]

If these amounts were to be collected from different groups (as discussed for collection of the MTC in Section 4), the relative impact varies substantially depending on the size of that group.

+ Collection from customers installing BTM solar in that year: assuming a 5-kW average system size and annual gross consumption of 8,900 kWh, this would equate to $0.25/kWh of gross consumption under current residential rates, or $0.07/kWh under the revised rates.[31]
+ Collection from all residential NEM customers: assuming the population of NEM customers grows from today's levels (approximately 1.04 million residential systems[32]) by five percent per year, there would be approximately 1.61 million residential systems in 2029. Using the same assumption of average annual gross consumption of 8,900 kWh per customer, the cost shift under the current

[30] 500 MW is an illustrative figure. For reference, recent annual installations of BTM solar systems in California have been closer to 1,000 MW (https://www.californiadgstats.ca.gov/). 1,700 MWh/MW is the average annual production from the solar profiles used to estimate bill impacts in the illustrative analysis described in Section 6.

[31] 8,900 kWh of annual gross consumption is based on the class average load shape used in the illustrative analysis described in Section 6.

[32] California Distributed Generation Statistics. California Solar Initiative. Available at: https://www.californiadgstats.ca.gov/.

rates and under the revised rates would equate to an additional $0.015/kWh or $0.005/kWh, respectively.

+ Collection from residential class: if these costs were instead socialized to the entire residential class of approximately 7.9 million customers across the three IOUs[33], assuming the same average consumption of 8,900 per household and no growth in residential accounts, this would equate to an additional $0.003/kWh or $0.001/kWh, respectively.

Glide Path 2: Flat Technology Costs

In the second illustrative glide path, we assume that pre-incentive BTM solar technology costs remain constant in real terms over the decade, rather than declining as in the first example.

Figure 10 below depicts the same three rate steps sequenced in over time as in the first example. The first vintage, through 2023, is identical to the previous example. However, beginning in 2024 once the ITC is no longer available, the assumption of no technology cost declines in this example results in the need for a MTC in the second vintage, providing an incremental $0.07/kWh of solar necessary to meet the 7.5-year payback. Once the rate steps down further in 2026, while technology costs remain constant, a larger MTC of $0.10/kWh is required.

Figure 10. Bill Reductions and MTC, Flat Technology Cost Scenario

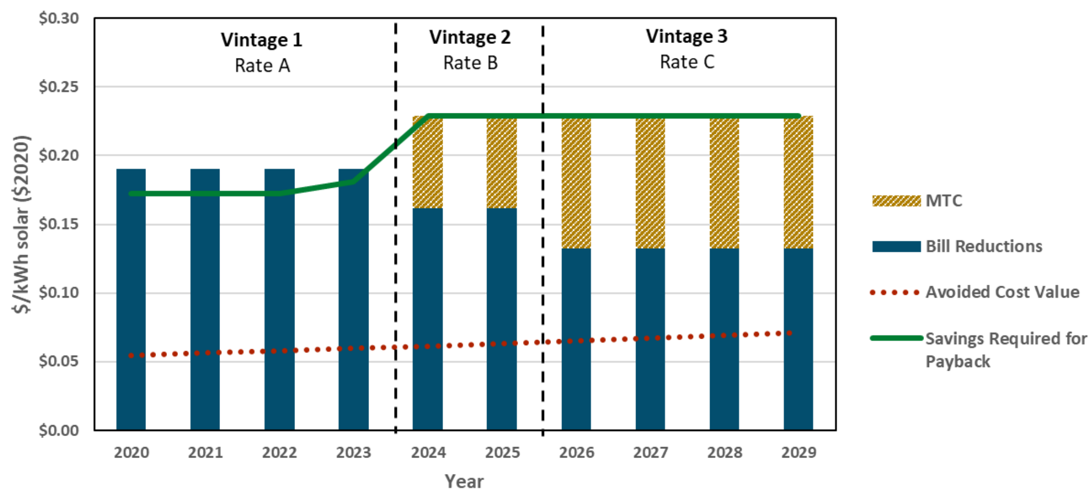
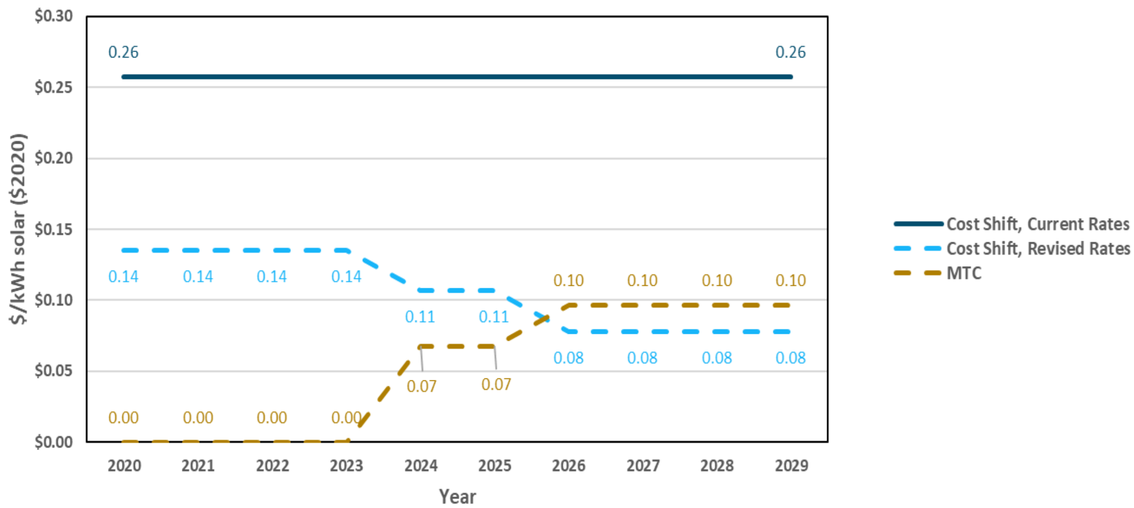


Figure 11 provides the same cost shift comparison as in the first illustrative glide path example, but also incorporates the $/kWh value of the MTC. As with the first example, the cost shift over time is reduced considerably relative to the cost shift under current rates. At the same time, the incremental MTC value grows over the second and third vintages (to $0.07/kWh and $0.10/kWh, respectively), as required to offset the rate changes (and resulting decrease in bill reductions) in the absence of technology cost declines.

[33] Energy Information Administration, Forms EIA-861(schedules 4A & 4D and) EIA-861S. No change from current customer counts assumed.

Figure 11. Cost Shift and MTC Comparison, Flat Technology Cost Scenario



The incremental cost shift at the end of the ten-year period is the same as in the first illustrative example under both current rates and revised rates, as the 2029 rate in effect (Rate C) is the same across both examples. However, in this second illustrative transitional period, the incremental MTC of $0.10/kWh must also be collected.

Using the same assumptions as in the previous example (500 MW of incremental installations), the total incremental MTC recovery surcharge in 2029 would be $82 million. If this MTC recovery surcharge and the residual cost shift amount ($66 million) were to be collected from the different groups discussed above in the first illustrative example, the result would be:

+ Collection from customers installing BTM solar in that year: $0.17/kWh in additional costs.
+ Collection from all residential NEM customers: $0.01/kWh in additional costs.
+ Collection from residential class: $0.002/kWh in additional costs.

As evidenced by the cost shift remaining at the end of the decade in both glide path examples, more rapid rate transitions – which could require larger MTC payments, depending on technology cost progression – might be merited. Moreover, given that the initial rate steps modeled above demonstrate that BTM customers do not currently need MTC credits to meet a 7.5-year payback period, there may be opportunity to progress rate transitions more quickly.

8. Conclusions

This white paper has illustrated that immediate elimination of the cost shifting under the current NEM program is not acceptable, as it could be in violation of California legislation and cause severe bill impacts. Accordingly, a MTC or similar transparent ratemaking tool has the potential to assist in gradually reducing the cost shift over time while preserving the health of the customer-sited renewable generation industry. The paper also discusses a gradual adoption of revisions to current residential TOU rates and provides illustrative examples of how such a transition could be paired with a MTC to meet the requirements of AB 327.

The improved rate designs would entail, among other things, lowering kWh charges to reflect time-of-use marginal cost levels, increasing fixed charges, and potentially including demand charges. This promotes economically efficient price signals, because it encourages customers to invest in DERs in a manner that is more aligned with their value to the grid, and alleviates intra- and inter-class cost shifts, including those from customer-generators to nonparticipating customers. The proposed illustrative rates also support electrification and GHG goals.

We recognize that the illustrative rate designs discussed in this paper, which include relatively large fixed and demand charges, would represent a large departure from current rates. These examples 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. While implementing large increases to residential fixed charges overnight is unrealistic, a gradual transition towards multi-part rates would make sense for all customers by more accurately reflecting the current and future cost composition of the electric grid. This paper explores how to achieve these objectives through a combination of rate design and external mechanisms such as a market transition credit.

In closing, E3 presents several questions for stakeholders to consider relative to the options discussed in this paper:

+ What is a reasonable payback period for BTM generation?
+ 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?
+ How should a MTC for customer-generators be structured?
+ Should MTC vintages be based on time (e.g., annual), number of participants, or capacity (e.g., MW blocks)?
+ 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?

E3 believes that addressing these questions – and the tradeoffs inherent in doing so – will inform a viable path forward for improving compensation of customer-sited renewable generation in California. It is our hope that discussion of these topics by stakeholders in the current proceeding will lead to a “glide path” for NEM that simultaneously mitigates cost shifting and maintains a viable customer-sited renewable generation industry in the state.

Appendix

New York

In March 2017, as part of the broader "Reforming the Energy Vision" process, the New York Public Service Commission initiated a stakeholder process to develop a process for transitioning from net metering to a value-based compensation structure for DERs through the "Value of Distributed Energy Resources" (VDER) tariff. The VDER "value stack" is currently available for most commercial and industrial projects and offers monetary compensation for total exports to the grid on an hourly basis based on different components of value provided to the electricity system. The resulting value is credited to the customer's next bill.

In Phase One, the value stack approach is intended for community solar and for large commercial and industrial customers. Mass-market, BTM solar (e.g., residential rooftop) interconnected before January 1, 2020 can remain under NEM compensation. Phase Two of the VDER mechanism opened the value stack option to residential and smaller commercial customers. The methodology for calculating VDER payments requires the use of advanced inverter and metering technology.

The VDER includes a number of value components:

+ Energy value is market-based and is determined by day-ahead hourly location-based marginal prices (LBMP).
+ Generation capacity value is derived from New York Independent System Operator (NYISO) capacity market auctions.
+ Distribution value of demand reductions includes two components, a system-wide distribution value (Demand Reduction Value, or "DRV") and, where applicable, an additional location-specific value ("Locational System Relief Value", LSRV") in highly congested areas. Both DRV and LSRV values are calculated on a $/kW-year basis by the utilities' based on their filed marginal cost of service studies. Compensation is tied to energy exports in 4-hour windows during summer non-holiday weekdays, with the locational value only applicable during utility-called events.
+ Environmental compensation is the higher of two values: 1) the applicable Tier 1 Renewable Energy Credit (REC) price or 2) the societal cost of carbon (SCC) less the Regional Greenhouse Gas Initiative (RGGI) CO_2 price that is converted to $/kWh based on grid emissions intensity, which is currently assumed to be constant during all hours.

The value stack for community distributed generation (CDG) installations further includes a Market Transition Credit (MTC). This component is intended to make up all or part of the difference between value stack compensation and NEM, thereby easing the transition to a cost-based tariff. This is applicable for the segment of the CDG that would otherwise be under NEM (only a portion of the CDG installation is subscribed by customers eligible for NEM).

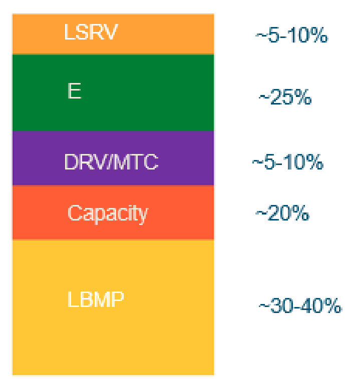
Customers under NEM that opt-in to the Value Stack compensation approach could qualify for the MTC if the resulting VDER tariff was lower than the customer's retail rate that would have been used under NEM. The MTC is scheduled to decline as tranches fill and they are fixed for each customer/project for a 25-year period.

A new Community Credit and a Community Adder have replaced the original MTC. The Community Credit is an additional benefit for Community Distributed Generation (CDG) projects on top of Value Stack compensation. The Community Credit is a similar structure to the MTC and provides an additional $/kWh value that is locked in for a 25-year period.[34] For utility service territories that have filled their allocated capacity eligible for Community Credits, a Community Adder has been established as a replacement. The Community Adder is also an additional incentive that a specified MW of community solar projects may qualify for if they were unable to receive the MTC or Community Credit. Each utility sets its own capacity limit and adder amount for the Community Adder. The Community Adder first became available in Orange & Rockland service territory in April 2019 and was extended to National Grid, NYSEG, and RG&E in May 2020.[35]

The PSC Order included provisions intended to limit impacts to nonparticipants via a 2 percent upper bound on the net annual revenue impact for each utility, to avoid cost shifting among customer classes.

An illustrative representation of the value stack components is shown in Figure 12 below:

Figure 12. VDER Value Stack components



The multiple phases of implementation of the value stack components have resulted in projects that are eligible for different components at different levels due to grandfathering and vintage. New York's Phase One NEM is still being offered to residential and commercial customers under 750 kW and compensates exports at the full retail rate.

Hawaiian Electric Companies

Hawaiian Electric Companies (HECO) established its first NEM tariff in 2009. The NEM tariff helped boost large amounts of BTM solar installations through 2015. The original NEM tariff closed to new customers in 2015 after reaching 1,515 MW of installed capacity, and the following interim options were established: Customer Grid Supply (CGS) and Customer Self-Supply (CSS). CGS compensated exports at a rate slightly

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34 NYSERDA, "The Value Stack." Available at: https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources.

35 NYSERDA, "Community Adder." Available at: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives/Community-Adder.

reduced from the full retail rate, determined by the Hawaii Public Utilities Commission. CSS is designed for systems that do not export to the grid and therefore do not involve customer compensation other than direct reduction of electricity consumption.[36] Additionally, HECO began implementing TOU rates in 2015. Solar permits have decreased since the switch from NEM to CGS in 2015, but the CGS program has still been popular.

In 2018, as CGS became fully subscribed, additional options (CGS Plus and Smart Export) were offered. CGS Plus continued to compensate exports at a Commission-approved rate but required systems to include grid support technology and allow for utility control. The Smart Export tariff also requires grid support technology and allows systems with renewable energy paired with storage to export to the grid from 4pm to 9am. Another program, NEM Plus, was also offered for existing NEM customers, allowing them to add non-export capacity to their home or business without affecting their existing NEM tariff.[37]

The HECO NEM successor tariffs have demonstrated that tariffs that are more cost-based relative to full retail compensation can still support a thriving local solar market. Additionally, the cost-based tariffs have been effective at spurring increased adoption of storage, which, although expensive, can be a valuable resource paired with increased solar penetration.

Arizona

Examples of demand charges instituted for residential rates reveal that they can be successfully adopted to compensate customer-sited renewable generation.

Arizona Public Service (APS) has revised residential rates and solar incentives to reflect the value of customer-sited renewable generation more accurately. New residential and commercial customers adopting solar generation are required to choose between two TOU rate options. One rate includes peak- and off-peak demand and energy charges, the second includes only peak- and off-peak energy charges but instead includes a Grid Access Charge (GAC) of $0.93 per kW of capacity of the solar facility's generation. Solar customers are compensated for their exports, at a fixed Renewable Comparison Proxy (RCP) per-kWh rate that is determined by tranches for new customers. Customers lock in their corresponding RCP for 10 years since they interconnect. The RCP cannot be reduced by more than 10 percent from the previous year's RCP. The current RCP is $0.1045/kWh.

Salt River Project (SRP) implemented a revenue-neutral, mandatory NEM rate structure in 2015, the "E-27 rate," by adopting TOU energy and TOU demand charges that vary by season. The energy charges were reduced below those in the regular TOU rate options offered to residential customers. The fixed charge was increased to recover more of the local distribution facilities costs and other fixed costs, and on-peak demand charges were included.[38] The demand charge had an inverted block structure, with the tail block

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[36] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar

[37] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/net-energy-metering-plus

[38] The E-27 rate monthly fixed charges for the NEM solar customers is $32.44 for homes with at or below 200-amp service entrance, and $45.44 for larger homes. By contrast, the fixed charge in the standard residential rate at the time was $20 per month. For a more detailed discussion of the SRP measures and other states see: *Nieto, A. (2016).*

price approximating marginal costs of generation capacity and transmission. The implementation of the new NEM rate slowed down the number of applications in SRP's service territory. Since then, SRP has adopted two additional optional TOU rates for solar customers, one with daily on-peak demand charges (as opposed to monthly) and another TOU rate option that uses a separate export price at avoided costs.

Nevada

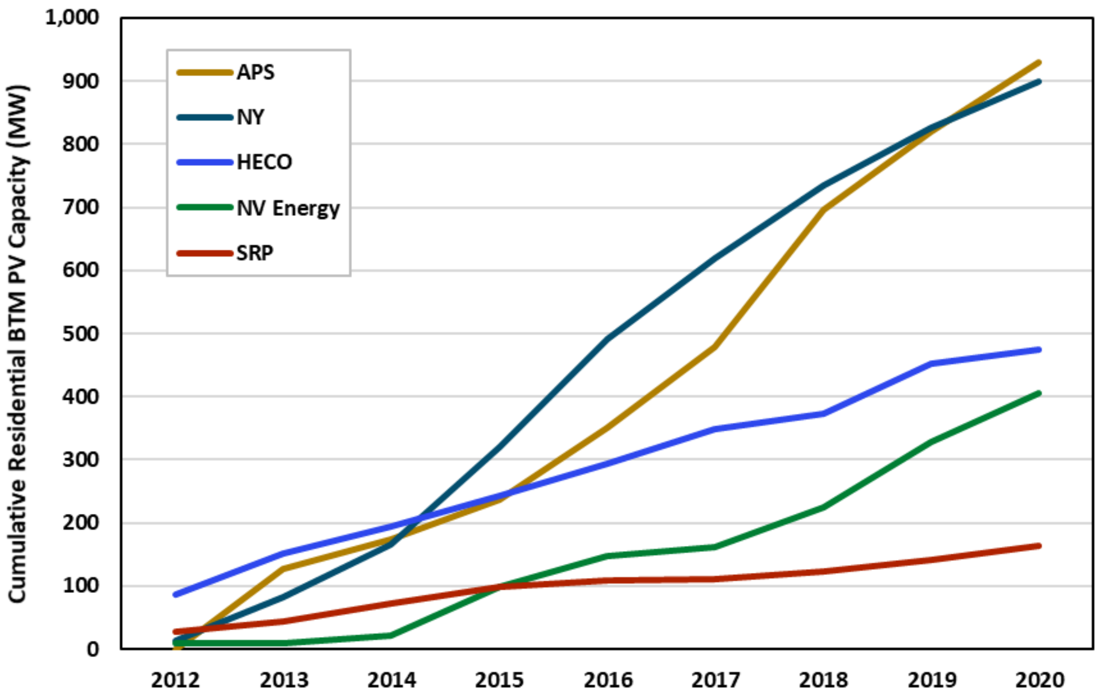
In 2015, the Nevada legislature approved a separate NEM customer class, but in June 2017, the legislature removed the separate class and ruled that NEM customers cannot be assessed any fees or charges that are different from those charged to non-NEM customers. Nevada now compensates grid exports at a percentage of the full retail rate to make sure that customers pay nonbypassable charges. The share of the retail rate that exports are compensated at was set to decline over time in 80 MW tranches. The first tranche received 95 percent of the retail rate for exports and this percentage is set to decline to 75 percent over four tranches, with each tranche keeping its retail rate percentage for 20 years after installation. In June 2020, Nevada reached its last tranche and exports for systems installed after June 2020 will accordingly receive 75 percent of the retail rate.

Optimizing Prices for Small-scale Distributed Generation Resources: A Review of Principles and Design Elements. The Electricity Journal, 31 – 41.

Installed Residential BTM Solar Capacity in Each Jurisdiction

Figure 13 provides a comparison of the cumulative residential BTM solar capacity in each jurisdiction discussed above, using data from the Energy Information Administration and HECO.[39,40]

Figure 13. Residential BTM Solar Capacity by Jurisdiction



[39] Energy Information Administration, Form 861. Data available at: https://www.eia.gov/electricity/data/eia861m/.

[40] Hawaiian Electric Companies, "Cumulative Installed PV -- As of Sept 30, 2020." Assumes 2020 weighted average residential proportion of total installed capacity. Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/clean_energy_facts/pv_summary_3Q_2020.pdf.