BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PROPOSAL OF
THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR
FOR A NET ENERGY METERING SUCCESSOR GENERAL MARKET TARIFF

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PROPOSAL OF
THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR
FOR A NET ENERGY METERING GENERAL MARKET SUCCESSOR TARIFF

The Solar Energy Industries Association (SEIA) and Vote Solar are pleased to present the Commission with a proposal for a successor tariff for net energy metering (NEM) in California. SEIA and Vote Solar submit this proposal in accordance with the Scoping Memo for this proceeding, issued November 19, 2020, and the Administrative Law Judge's (ALJ) email ruling (Ruling) dated January 28, 2021, which set forth the requested outline for these proposals. As specified in the Ruling, we begin with a summary of our proposal, and conform the organization of the proposal to the ALJ's outline. We provide a detailed description of our proposal and the supporting cost-effectiveness analysis, and discuss how our proposal complies with the relevant statutes and the guidelines for a successor tariff that the Commission adopted recently in Decision (D.) 21-02-007. We will provide further technical and policy support for our proposal in direct and rebuttal testimony to be served on April 23 and May 21. We also discuss how our proposal is in substantial alignment with the concepts for a successor tariff presented in the white paper released on January 28 from the Commission's consultants, Energy and Environmental Economics (E3) and Verdant Associates. Finally, we propose a schedule for the next steps that the Commission should pursue to implement the successor tariff.

As requested in the March 5, 2021 email ruling, the SEIA and Vote Solar have designated the following representative to present the SEIA and Vote Solar Proposal at the workshop on March 23-24, 2021: R. Thomas Beach (tomb@crossborderenergy.com).

I. SUMMARY

Overview. In 2005 California set a goal of a million solar roofs. With this Commission's leadership, and the private investments of millions of California citizens, that historic milestone was met. The California solar industry employs 75,000 workers and has invested $70 billion dollars in the state's economy. California now has an even more ambitious goal to reach 100% clean energy by 2045. That goal cannot be achieved without new investments from millions of Californians in an array of distributed energy resources (DERs) – not just distributed generation (DG) from solar and wind, but also battery storage, electric vehicles (EVs), and electric heat pumps. California cannot rely solely on utility-scale electric resources to meet the 2045 goal, if the state is also to reach its ambitious goal to conserve 30% of its lands -a portion of our clean energy needs must be sited in the built environment, in the load centers. Further, to meet the challenges of a changing climate, we need to develop a more resilient energy system, where significant electricity can be produced and stored on-site. Finally, as our energy systems evolve to meet these new goals, we must ensure that clean DERs are broadly available to all Californians, including low-income consumers

In this context, it is critical that state policy continues to foster the sustainable growth of solar and solar-plus-storage resources. The NEM program is foundational to that effort, as it ensures that customers who invest in renewable DG receive a fair return on their investment. SEIA and Vote Solar fully recognize that the residential NEM program should be updated, for these reasons: (1) to integrate the program with the state's efforts to encourage electrification, (2) to encourage the growth of solar-plus-storage resources that can shift solar output to serve peak period loads, (3) to align over time the costs and benefits of DER adoption for both participating and non-participating ratepayers, and (4) to increase access for low-income customers.

The SEIA / Vote Solar proposal. We propose that the new "NEM 3.0" general market tariff for residential customers should use a net billing structure. Under net billing, the customer with renewable DG would pay a different rate for energy received from the utility (i.e. imports) than for the excess generation that the DG customer delivers to the utility (i.e. exports). There are two principal pillars to the Vote Solar / SEIA net billing proposal:

- **Service on an electrification rate.** For imports from the utility, the residential DG customers of PG&E and SDG&E would be required to take service from one of the utility's available untiered time-of-use (TOU) rates designed to promote beneficial electrification. The structure of these rates will provide a strong incentive for new DG customers to include storage, which will increase significantly the value of these systems. to the grid. This requirement would take effect in 2023, at the outset of the NEM 3.0 program. The residential customers of SCE would continue to be allowed to use the residential default TOU rates, as well as SCE's electrification rate, because the design of SCE's rates has more aggressive TOU pricing, and SCE's lower residential rates present fewer concerns with non-participant impacts than the other two IOUs.

- **Five-year stepdown in compensation, focused on reducing the export rate.** The compensation for residential DG customers under NEM 3.0 would be gradually reduced over time from the level set in the current NEM 2.0 tariff, in a series of five steps. The first step, and the first significant reduction, will occur in 2023 with PG&E and SDG&E residential customers required to use the electrification rate. The remaining four steps will reduce the export rates for all three IOUs, with each step triggered when specific aggregate capacities of residential systems are installed under NEM 3.0 on each IOU system. The steps that we propose would reduce the export compensation for PG&E and SDG&E NEM customers by 50% by 2027; for SCE NEM customers, by 25% by 2027.

The goal of both the electrification rates and the export stepdowns is to bring the bill savings for DG customers into alignment, over a five-year period (2023-2027), with the benefits of this new renewable generation, as measured by the Commission's 2020 Avoided Cost Calculator (ACC). To promote electrification, it is important that NEM customers be allowed to oversize their systems by up to 50%, to provide for the significant load growth that will result from the adoption of other types of DERs such as EVs and heat pumps. Excess output should be compensated based on the avoided costs in the 2020 ACC, to provide ratepayer indifference.

Vote Solar and SEIA do not recommend any changes to the current NEM 2.0 tariff for non-residential customers. The growth in this market has lagged in recent years, and the lower volumetric rates applicable to these customers do not have the same impacts on non-participants as do residential rates.

Statutory requirements. There are four statutory requirements that the Commission's adopted NEM successor tariff must meet. Our proposal satisfies all of these requirements:

1. **Ensure that customer-sited renewable distributed generation continues to grow sustainably.** It will be challenging for the industry to move to higher-cost solar-plus-storage systems while facing both reduced export compensation and the expiration in 2024 of the federal solar tax credit. The SEIA/ Vote Solar proposal is tailored to promote the continued growth of the residential market for renewable DG by making a gradual change to compensation that will allow a reasonable opportunity for customers to invest.
2. **Include specific alternatives designed for growth among residential customers in disadvantaged communities.** This general market tariff is designed to work in conjunction with the proposals offered by Vote Solar and other parties that are expressly targeted to reach low income and disadvantaged communities.

3. **Ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility.** We show that the benefits of new solar and solar-plus-storage facilities – in terms of the costs that they will allow the utilities to avoid – are greater than the capital and operating costs of these systems. These resources thus pass the Total Resource Cost test and will be cost-effective additions to the utility system.
4. **Ensure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.** If the Commission interprets this statute as requiring it to examine the impacts of the tariff on participating versus non-participating ratepayers, the SEIA / Vote Solar proposal produces improved scores on the RIM test over time, bringing lost revenues (i.e. bill savings) from NEM 3.0 customers into alignment, over a five-year period (2023-2027), with the benefits (i.e. the avoided costs) of this new renewable DG. Further, the Commission should take a broader view of the equities between participating and non-participating ratepayers than just the scores on the too-stringent RIM test.

Comparison to the E3 White Paper. We commend E3 for advancing a conceptual proposal for the successor tariff that emphasizes striking a balance between the parrallel goals of AB 327 – aligning compensation for customer-sited renewable DG with the benefits that these systems provide to the electric system, while at the same time allowing these resources to grow sustainably. Many of the conceptual elements of E3's suggested successor tariff are also included in our proposal, including a net billing structure with changes to export rates, gradualism, calibration of the proposal to the economics of renewable DG, and consideration of the links with beneficial electrification. We differ from E3 on the need to calculate a "Market Transition Credit," whose calculation and recovery would raise difficult equity and implementation issues that our proposal avoids. We also strongly recommend that the Commission should use the existing electrification rates that have been developed with broad input and as a platform for many types of DERs, rather than the solar-specific rate designs that E3 explores. Finally, The E3 paper does not focus on the growth of the solar-plus-storage systems that will be the future of renewable DG in California.

Open issues. The SEIA/Vote Solar proposal relies on PG&E's and SDG&E' s NEM 3.0 customers in taking service on an electrification rate. Currently, SDG&E does not have an untiered residential electrification rate open to all customers, but is scheduled to file an application for such a rate in September 2021. If there is a delay in processing this case, then NEM 3.0 customers would temporarily need to be placed on a similar existing rate, such as DR-SES or EV-TOU-5, that today have limited availability.

II. TOTAL RESOURCE COST ANALYSIS OF DISTRIBUTED SOLAR AND SOLAR-PLUS-STORAGE

The Commission has adopted and affirmed repeatedly that the Total Resource Cost (TRC) test should be the principal cost-effectiveness test for demand-side resources.[1] The TRC test measures whether the benefits of renewable DG to all customers and the electrical system approximately equal or exceed the costs of these facilities. Although the TRC is not impacted directly by the net metering tariff under which DG customers take service, the test does indicate whether these demand-side resources are beneficial to all ratepayers and the system as a whole. Accordingly, as a preface to our NEM proposal, SEIA and Vote Solar have performed a forward-looking, life-cycle TRC analysis of distributed solar and solar-plus-storage systems. In the TRC test, the costs are the lifecycle levelized cost of energy (LCOE) from solar and solar-plus-storage resources. The benefits used in the test are the utilities' long-run avoided costs, also levelized over the life of the resources. As presented below, both types of distributed resources pass the TRC test, with an average TRC ratio of benefits to costs over the period 2022 to 2030 of 1.30 for solar and 1.23 for solar-plus-storage. With resiliency benefits included, the average TRC for solar-plus-storage increases to 1.41. The results of this analysis show that the benefits are similar to or exceed the costs throughout the 2022-2030 period; in other words, these demand-side resources are beneficial to all ratepayers and the system as a whole.

On the cost side of the TRC analysis, **Table 1** shows the key assumptions for the 25-year LCOEs from residential solar and solar-plus-storage systems. The assumptions for the capital costs of the resources are derived from 2019-2020 costs reported in Lawrence Berkeley National Lab's (LBNL) 2020 data update for its annual *Tracking the Sun* reports[2] and in the California Distributed Generation Statistics website.[3] We assume that residential solar capital costs decline at 6% per year, consistent with the historical trend in these costs.[4]

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1 See D. 09-08-026, at pp. 28-29; D. 19-05-019, pp. 19 and 24; and D. 21-02-007, at pp. 6-7.

2 Available at https://emp.lbl.gov/tracking-the-sun.

3 See https://www.californiadgstats.ca.gov/charts/, especially the Cost per Watt chart.

4 See LBNL 2020 data update, at Slide 21. The National Renewable Energy Lab's (NREL) *2020 Annual Technology Baseline* (2020 ATB) shows residential solar costs in California declining at 8.5% per year from 2021-2030. See https://atb.nrel.gov/electricity/2020/data.php. We are using the more conservative historical rate of decline.

Table 1: *Assumptions for the 25-year Levelized Cost of Residential Solar and Solar + Storage*

Assumption	Value
Solar Capital Costs, 2021-2030	LBNL *Tracking the Sun* 2020 data update, California Distributed Generation Statistics website
Federal ITC	26% through 2022, 22% in 2023, 0% thereafter
Solar output	NREL PVWATTS
Solar degradation	1.4% per year, per NEM 2.0 Lookback Study
Financing Cost	5%
Participant discount rate	8%, per NEM 2.0 Lookback Study
Inflation	2.2%
Financing Term	20 years
Inverter Replacement	$150 per kW-DC in Year 15
Maintenance Cost	$20 per kW-DC per year, per NREL 2020 ATB
Storage System Size	11.25 kWh
Storage Capital Cost	$750 per kWh
Storage Balance of Systems	25% of storage cost
Storage Incentive	($200 per kWh) – SGIP incentive
Storage Efficiency	85% (i.e. 15 % round-trip losses)

We have used a pro forma cash flow analysis to project the 25-year LCOEs from residential solar and solar-plus-storage systems, with the assumptions shown in Table 1. **Table 2** shows these results. The LCOEs generally decline due to expected decreases in the capital costs for solar, except in 2024 when the expiration of the federal investment tax credit (ITC) for residential solar causes the LCOEs to rise. We keep storage costs flat at today's levels, given the uncertainty over the trajectory of future battery costs.

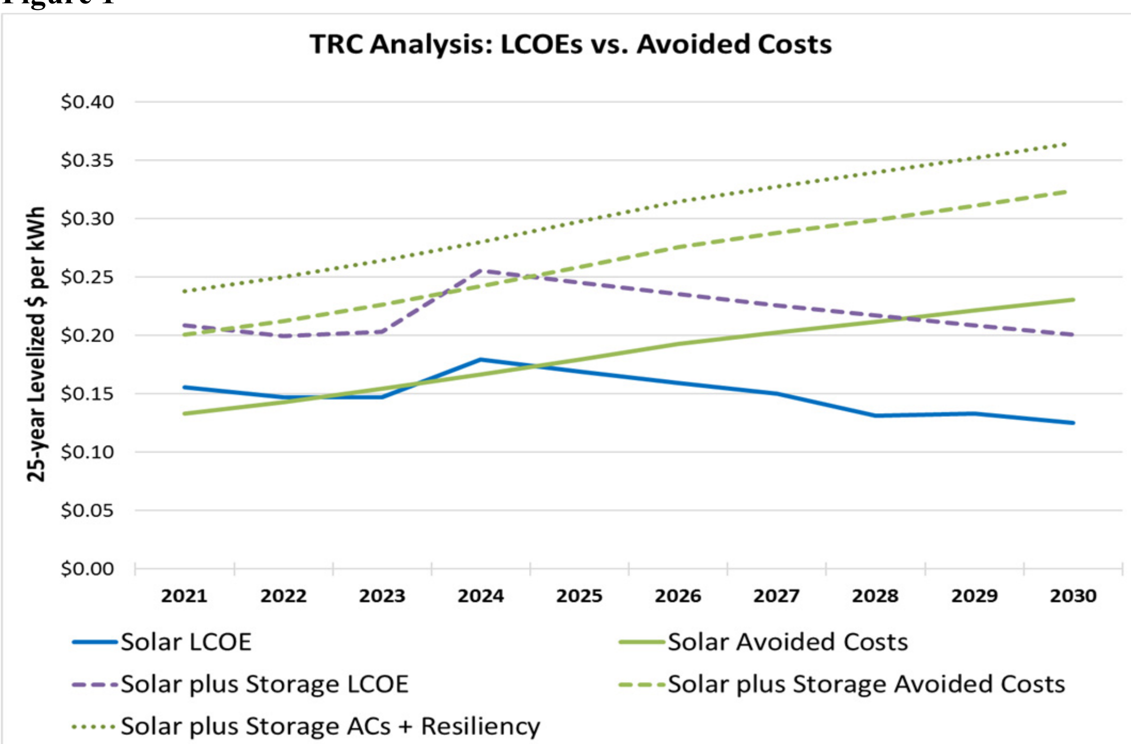
Table 2: *LCOEs for residential solar and solar-plus-storage (25-year levelized $/kWh)*

Year	Solar	Solar + Storage
2022	$0.147	$0.200
2023	$0.147	$0.203
2024	$0.179	$0.255
2025	$0.169	$0.245
2026	$0.159	$0.235
2027	$0.150	$0.226
2028	$0.131	$0.217
2029	$0.133	$0.209
2030	$0.125	$0.201

In the TRC test, the benefits of distributed solar are the utilities' avoided costs – the future costs for supply-side resources that these distributed solar resources will allow the IOUs to avoid – as determined by the 2020 Avoided Cost Calculator (2020 ACC) that the Commission adopted in D. 20-04-010. We have applied the hourly avoided costs from the 2020 ACC to representative output profiles for residential solar and solar-plus-storage resources in the IOU service territories, to determine the direct costs that will be avoided by these DG resources. We calculate these avoided costs on a 25-year levelized basis in each year from 2022 to 2030.[5]

Finally, to complete the TRC analysis, we compare the LCOEs of residential solar and solar-plus-storage to the avoided cost benefits of these resources. The results are shown in **Figure 1**. The benefits equal or exceed the costs throughout the 2022-2030 period. The average TRC ratio of benefits to costs over the period is 1.30 for solar and 1.23 for solar-plus-storage. The figure also shows the benefits of solar-plus-storage when the resiliency benefits discussed below and in Attachment B are included (the dotted green line). With these resource-specific benefits included, the TRC score for solar-plus-storage increases to 1.41.

Figure 1



5 The costs and benefits in the final years of the period are levelized over less than 25 years because the 2020 ACC only includes avoided costs extending to 2050.

III. THE SEIA / VOTE SOLAR NEM 3.0 PROPOSAL

A. Residential general market tariff

SEIA and Vote Solar present below a proposal for the NEM 3.0 general market tariff. Our proposed general market tariff focuses on the residential market and on middle- and higher-income customers. This tariff would apply to residential customers with incomes above 80% of the Area Median Income (AMI), which we will refer to here sometimes as "general market residential customers" or "residential customers" for brevity. Vote Solar has developed a separate proposal for low-income residential customers with incomes at or below 80% AMI, jointly filed today with GRID Alternatives and Sierra Club. SEIA supports this separate proposal for lower-income customers.

1. Net billing structure

SEIA and Vote Solar propose that the NEM 3.0 general market tariff for residential customers should use a net billing structure. Under net billing, the customer with renewable distributed generation (DG) would pay a different rate for energy received from the utility (i.e. imports) than for the excess generation that the DG customer delivers to the utility (i.e. exports). There are two principal pillars to the SEIA/Vote Solar net billing proposal:

- **Service on an electrification rate.** For imports from the utility, the DG customer would be required to take service from one of the utility's available untiered residential time-of-use (TOU) rates designed to promote beneficial electrification that reduces carbon emissions. The structure of these rates will provide a significant incentive for new DG customers to include storage in their DG systems, which will increase significantly the value of these systems to the utility system. This requirement would take effect in 2023, at the outset of the NEM 3.0 program. The one exception to this policy would be Southern California Edison (SCE), whose NEM 3.0 residential customers also would be allowed to use that utility's residential default TOU rates, TOU-D 4p-9p and 5p-8p, as well as SCE's electrification rate TOU-D-PRIME. As explained further below, SCE's residential default rates have more aggressive TOU pricing, and the utility's lower overall rates present significantly reduced concerns with non-participant impacts than the other two IOUs.

- **Five-year stepdown in compensation, focused on reducing the export rate.** The compensation for residential DG customers under NEM 3.0 would be gradually reduced over time from the level set in the NEM 2.0 tariff, in a series of steps. The first step, and the first significant reduction, will occur in 2023 with the requirement to use the electrification rate. The remaining reductions will focus on the export rate, and will occur in four steps, with each step triggered when specific aggregate capacities of residential solar or solar-plus-storage systems are installed under NEM 3.0 on each IOU system. We propose to use a system similar to the capacity-based stepdowns in the successful ten-year California Solar Initiative (CSI) program.

The goal of both the electrification rates and the export stepdowns is to bring the bill savings for customers with DG into alignment, over a five-year period (2023-2027), with the benefits of this new renewable generation, as measured by the Commission's 2020 ACC. This will reduce and ultimately eliminate any adverse impacts associated with customers who elect to use their private capital to serve their own load, behind the meter, with new renewable generation that helps California to meet its climate and clean energy goals. Our proposal builds on the initial steps in this direction taken in the current NEM 2.0 structure adopted in D. 16-01-044, which required NEM 2.0 residential customers to take service under a TOU rate and began to reduce export compensation by removing certain non-bypassable charges (NBCs) from the export rate.

2. Description of methodology for calculating export compensation

The stepdowns in export compensation that Vote Solar and SEIA propose for each IOU are calibrated to bring the benefits and costs of the NEM 3.0 program for non-participants into alignment over approximately a five-year period starting in 2023. For PG&E and SDG&E, we propose to reduce export compensation by a total of 50% in four steps. After an initial step in which the use of an electrification rate would be required, the second step would begin to reduce export compensation, with the export rate set at 95% of the retail rate less NBCs. The subsequent steps for PG&E and SDG&E, with the export percentage for each step, are shown in **Table 3**. As shown in the table, we are proposing that the stepdowns in the export percentage gradually increase in size. This is because the requirement that PG&E and SDG&E general market residential NEM 3.0 customers must use an electrification rate will result in a substantial and immediate reduction in bill savings in 2023. It is important to provide the industry with time to adjust to this change before making the larger reductions in export rates. The industry will clearly have to adapt to longer and more difficult cycle times, leading to higher installation costs, associated with the installation of solar-plus-storage rather than simply solar systems. This is aside from a possible shortage in battery systems suitable for financeable home solar installations in California and the 2024 expiration of the federal ITC for residential solar.

SCE has significantly lower rates and slightly higher avoided costs than PG&E and SDG&E, and therefore each step for SCE can be smaller. We propose to reduce export compensation for SCE by a total of 25% over the four steps. The initial step for SCE in approximately 2024 will set the export rate at 95% of the retail rate less NBCs. The further stepdowns in the export percentages for SCE are also shown in Table 3.

Table 3: *Stepdowns in Export Percentages*

Step	Export Percentages		*Expected Year for Each Step*
	PG&E and SDG&E	SCE	
1	Electrification rate	Electrification rate	*2023*
2	95%	95%	*2024*
3	85%	90%	*2025*
4	70%	85%	*2026*
5	50%	75%	*2027*

The export percentage in each step will apply to all residential general market customers who install a new NEM 3.0 system during that step and will be used to calculate the export rate for those customers for a 20-year period. Fixing the export percentage for 20 years provides needed certainty supporting the customer's long-term investment in new clean energy infrastructure. Thus, for example, all PG&E NEM 3.0 customers who install a system during the second step will receive an export rate equal to 95% of the retail rate less NBCs for the next 20 years.

We propose that the size of each step should be equal to one year of expected residential solar or solar-plus-storage installations, in MWs, based on each IOU's annual average residential NEM additions over the last five years (2016-2020),[6] as shown on the bottom line of the following table. All residential installations – whether under the general market tariff or a separate program for low-income customers – should count toward the capacity used in each step.

[6] This data is from the California Distributed Generation Statistics website and data base, https://www.californiadgstats.ca.gov/.

Table 4: *Residential NEM Installations (MW) from 2016-2020*

Year	PG&E	SCE	SDG&E
2016	382	281	163
2017	323	246	103
2018	366	250	137
2019	413	276	176
2020	384	240	134
Average[7]	**375**	**260**	**145**

SEIA and Vote Solar submit that a continuation of residential installations at the same pace experienced over the last five years is consistent with both AB 327's goal of sustainable growth for the solar industry and the expected increase in customer-sited PV in the California Energy Commission's (CEC) current statewide demand forecast.[8] As a result, we assume that each step will take approximately a year to complete, resulting in the expected stepdown schedule for the export rates of each of the IOUs shown below in **Table 5**. We propose a different means to manage the end of each step than used in the CSI program, where the end to the steps based on capacity proved less-than-transparent for customers and installers and resulted in significant market uncertainty. To manage the end of each step, we propose that, when an IOU projects that the cumulative NEM 3.0 installations on its system are within three months of the end of each step, the IOU will announce a date certain in three months for the end of that step. A time-based end to each step will provide potential customers with longer and more certain advance notice of the end of each step, and will be easier for the IOUs to manage.

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7 Averages are rounded up or down to the nearest 5 MW.

8 The CEC's 2019 final *Integrated Energy Policy Report* states, at page 209, that PV self-generation is expected to grow, in the mid-case demand forecast, from 8,000 MW at the end of 2018 to 23,300 MW in 2030, for annual average growth of 1,275 MW per year over these 12 years. See https://efiling.energy.ca.gov/getdocument.aspx?tn=232922. This forecast includes solar growth statewide, including among publicly-owned utilities.

Table 5: *Stepdown Schedule for Export Rates*

Step	Export Percentage		Cumulative MW at the End of Each Step			*Expected Year for Each Step*
	PG&E and SDG&E	SCE	PG&E	SCE	SDG&E	
1	Electrification rate	Electrification rate	375	260	145	*2023*
2	95%	95%	750	520	290	*2024*
3	85%	90%	1,125	780	435	*2025*
4	70%	85%	1,500	1,040	580	*2026*
5	50%	75%	1,875	1,300	625	*2027*

Given that NEM 3.0 will represent a significant change and a substantial challenge for the solar and storage industries, it makes sense that the pace of the stepdowns in the export rate should be governed by the rate at which NEM 3.0 capacity is installed. The requirement in the first step that general market tariff customers for PG&E and SDG&E must use an untiered electrification rate with an aggressive TOU rate structure will present installers with a significant new challenge in marketing and customer education. The electrification rates are best suited for solar-plus-storage systems that can be cycled daily, charging from solar output in the off-peak hours and discharging in the on-peak period. Although such systems are beginning to be installed widely, their penetration is still low.[9] Further, there are concerns with the ability of the industry to pivot to solar-plus-storage systems due to constraints in the supply chain for batteries, which may limit the uptake of solar-plus-storage systems under the electrification rates.[10] For these reasons, it makes sense to regulate the pace of the stepdowns in the export rate according to the rate at which NEM 3.0 capacity is installed. Further, the size of the stepdowns should be more measured in the earlier years. If the uptake of NEM 3.0 systems is faster than the historical pace of NEM 2.0 installations, then the export compensation can be reduced more rapidly.

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[9] Figure 3-4 of the NEM 2.0 Lookback Study, at p. 27, shows that about 6% of solar systems installed in 2019 included storage. Our review of the interconnection databases for solar and storage shows that more than 10% of the solar systems installed in PG&E's territory in 2020 included storage.

[10] For example, in recent years there has been significant growth in the battery storage market, driven in part by higher demand for EVs. There is surging demand in the market for the raw materials used in lithium-ion batteries. See https://www.axios.com/battery-shortage-risk-electric-car-era-fa699bfb-9d57-4bdc-b907-993903cc7620.html; also https://www.forbes.com/sites/arielcohen/2020/03/25/manufacturers-are-struggling-to-supply-electric-vehicles-with-batteries/?sh=6e878f271ff3. High and increasing demand in the market is leading to longer lead times for components and hampering the solar industry's ability to sustain the growth of systems paired with storage.

Conversely, if the change to NEM 3.0 slows installations, then the progress through the steps can be moderated, keeping higher export rates in place longer as the industry takes the necessary time to adapt. This is another reason why the reduction in the export rates is larger in the later steps, particularly for PG&E and SDG&E.

Vote Solar and SEIA have analyzed how this stepdown structure balances the benefits and costs of distributed solar and solar-plus-storage systems. We have applied the Ratepayer Impact Measure (RIM) test to typical solar and solar-plus-storage systems. The RIM test is the most stringent of the Commission's cost-effectiveness tests measuring the impact of a demand-side program or DER technology on non-participating ratepayers. In the RIM test, the principal costs are the bill savings for the DER customer, which are also the revenues that the utility loses as a result of the DER installation. The principal benefits in the RIM test are the long-run costs avoided by the utility, as measured by the 2020 ACC. In making this comparison, it is critical to use a long-run, lifecycle comparison because new customer-sited solar systems are long-term capital investments with a useful economic life of 25 years. To do this, on the benefit side we use the 2020 ACC to calculate the 25-year nominal levelized avoided costs for the total output of the solar and solar-plus-storage systems, including the expected degradation in solar output over time.[11] We also consider the quantifiable benefits to the state's electric system from the increased resiliency that solar-plus-storage systems provide.[12] On the cost side, we calculate the 25-year levelized bill savings (i.e. the revenues that the utility loses) from the total output of solar and solar-plus-storage systems. We assume that IOU rates escalate at 3.5% per year,[13] with

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[11] We use the solar output degradation assumption reported in the Lookback Study, at p. 63.

[12] Resilient on-site backup systems have broad public benefits in maintaining essential electric service to critical public safety, health, and welfare services, to essential economic activities, and to provide a long-term foundation for more resilient neighborhoods. In a "black sky" event such as an earthquake that disrupts the power grid for an extended period, customers without backup will benefit from the fact that several of their neighbors and the local community center have electricity from on-site solar-plus-storage systems. Consistent with the direction provided by Decision 20-04-020 that "consideration of the benefits of grid services provided by specific distributed energy resources should be addressed in resource-specific proceedings," SEIA and Vote Solar provide **Attachment B** which discusses in detail the quantifiable benefits of resilient solar-plus-storage systems, Further, the California utilities are poised to spend millions in ratepayer dollars to deploy fossil-based micro-grids to enhance resiliency; these represent ratepayer costs with significant environmental impacts that potentially are avoidable by solar-plus-storage systems.

[13] We escalate rates at 3.5% per year from 2021-2030, based on the 2021-2030 rate forecast presented by the CPUC Energy Division at the February 21, 2021 Commission *en banc* hearing on electric rates in California. We have used the lower end of the range of Energy Division's rate escalations for the three IOUs, because the *en banc* also recognized the potential for electrification to moderate future

this escalation offset by reduced solar output over time due to degradation. The bill savings for all PG&E and SDG&E systems use the IOUs' electrification rates, which we discuss further in the next section. For SCE, we assume solar installations use the default TOU rate (TOU-D 4p-9p), while solar-plus-storage systems move to the electrification rate (TOU-D-PRIME) We also assume a mix of solar and solar-plus-storage systems, with the percentage of solar-plus-storage systems starting at 20% in 2023 and increasing by 10% per year thereafter. We expect the percentage of solar-plus-storage systems to increase over time, because storage allows customers to shift solar output into the evening 4p-9p on-peak period when power is most valuable. Customers also are attracted to the ability of solar-plus-storage systems to provide a backup supply of electricity during increasingly frequent grid outages due to extreme weather and wildfire events driven by climate change.

The results of these RIM test comparisons are shown in **Figures 2 to 4** below. The orange lines are the 25-year levelized bill savings under the SEIA's and Vote Solar's proposed general market tariff, for the mix of solar and solar-plus-storage systems expected to be installed in each year starting in 2023. The solid green lines are the 25-year levelized avoided cost benefits from the 2020 ACC, again using the same mix of solar and solar-plus-storage systems. The dashed green line is the 2020 ACC benefits plus the resiliency benefits of the solar-plus-storage systems. The figures show that expected average bill savings for PG&E and SDG&E decline significantly in 2023 compared to bill savings under the default TOU rates under the NEM 2.0 program (red dashes). The NEM 3.0 bill savings are relatively flat for several years, then decline more sharply in 2026-2027. This result is due to the proposal to accelerate the stepdowns in export compensation over time. In addition, the stepdowns in export compensation are offset to some extent, first, by the growth in solar-plus-storage systems that offer significantly higher bill savings and, second, by rate escalation. By 2027 the avoided cost benefits of solar and solar-plus-storage systems closely approach or equal the costs (bill savings) for all three IOUs.

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rate escalation. After 2030, we assume rates increase with inflation. See Slides 3 and 16 of the Energy Division's presentation of its white paper, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Rates%20En%20Banc_white%20paper_v.2.0.pdf.

We have also quantified in dollars the savings to IOU ratepayers from our general market tariff proposal, compared to a continuation of NEM 2.0, over the 2023-2030 period. The savings compared to NEM 2.0 are almost $1 billion ($960 million).

Figure 2

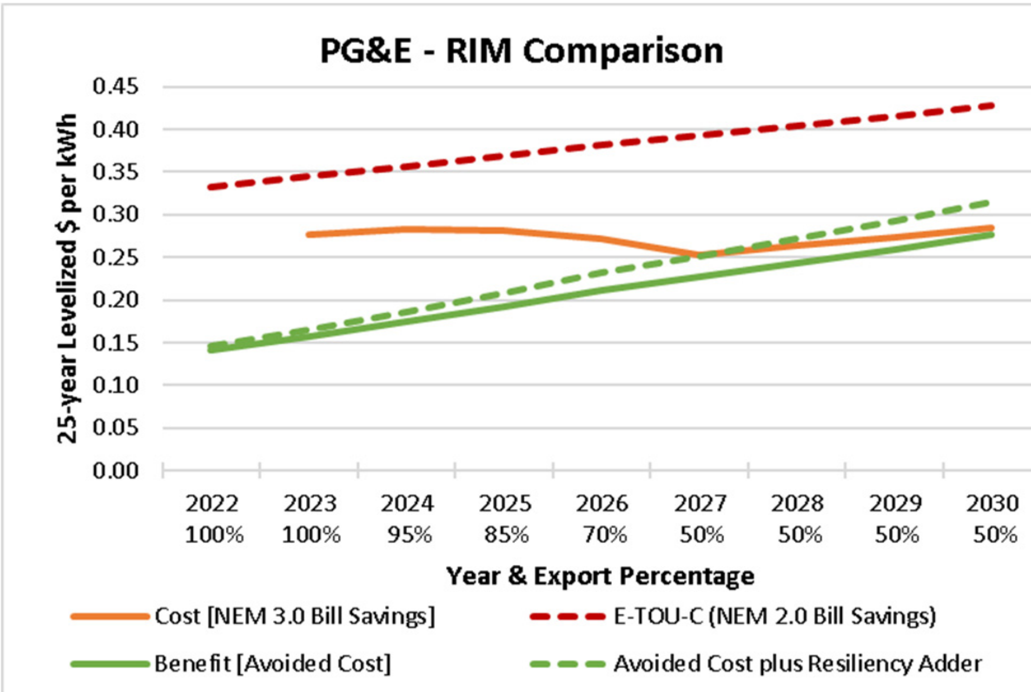


Figure 3

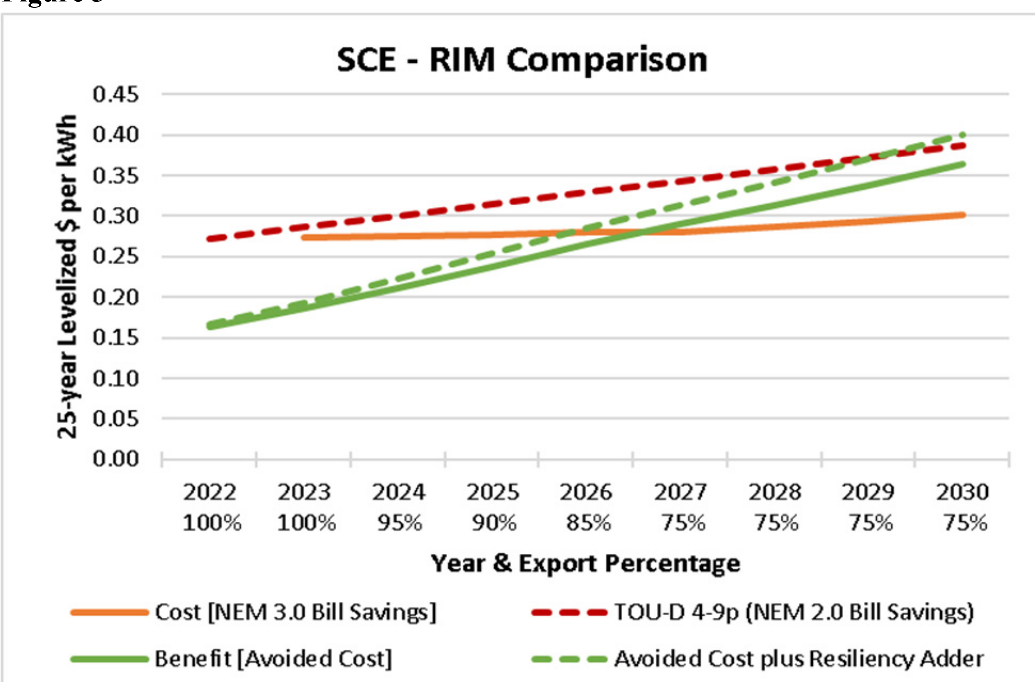
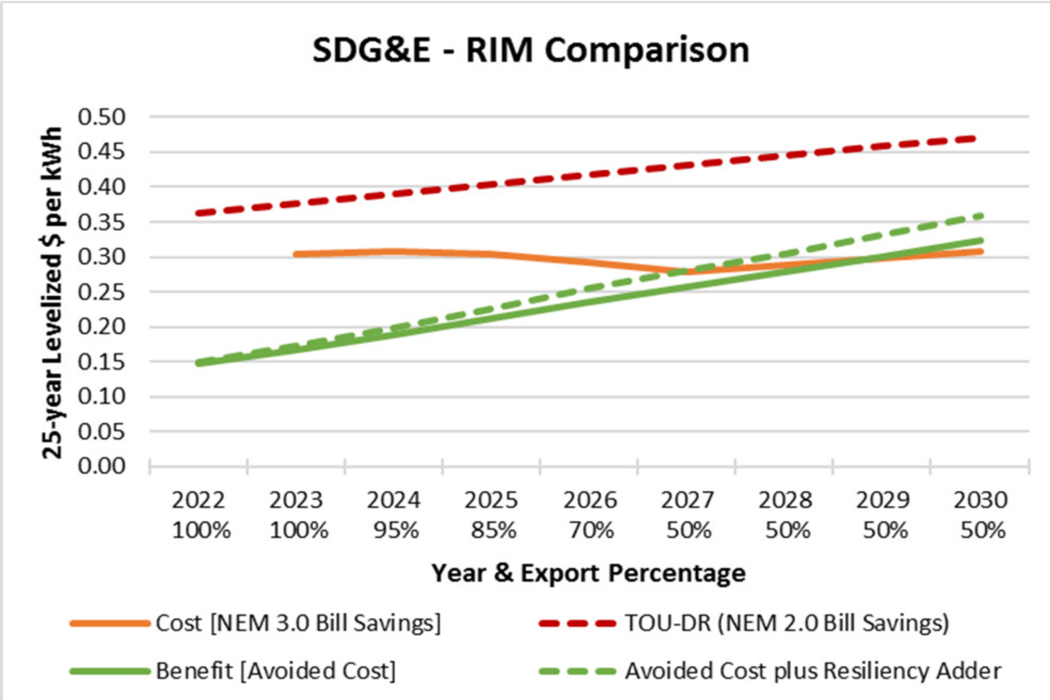


Figure 4



3. Rate structure

The first pillar of the Vote Solar/SEIA NEM 3.0 proposal is the use of the TOU rates that the Commission has adopted recently to promote electrification. These rates have large differences between on- and off-peak rates – differences that are closer to marginal costs and that are much larger than those in the introductory "TOU-lite" default TOU rates that the Commission has adopted for SDG&E and PG&E. The electrification rates will result in significantly lower compensation for solar-only systems, compared to SDG&E's and PG&E's default TOU rates, because they have lower off-peak rates that apply in most of the daytime hours of maximum solar output. At the same time, they will encourage customers adopting solar to include on-site storage with their systems, due to the savings that can be achieved by shifting solar output into the 4p-9p on-peak period. There are substantial system benefits from using storage to move solar output to the on-peak hours, as shown by the high avoided costs in these hours in the 2020 ACC. Thus, encouraging the transition to solar-plus-storage systems will be the most constructive way to meet the Commission's goals: (1) enhance the value of distributed solar to the grid, (2) reduce and ultimately eliminate any adverse impacts on non-participating ratepayers, and (3) allow the solar industry to continue to grow sustainably while adapting to the current realities of California's electric system. Importantly, this includes adding on-site storage capacity that can address the state's critical need for new capacity.

The current and anticipated electrification rates for each IOU are shown in **Table 6**. Two residential electrification rates were developed and approved in PG&E's and SCE's last GRC Phase 2 case, PG&E's EV2 rate and SCE's TOU-D-PRIME rate. Several of these rates are still under development. In D. 20-03-003, the Commission ordered PG&E and SDG&E to propose a residential TOU rate that is untiered, includes a fixed charge, and is designed to promote electrification, similar to the EV2A and TOU-D-PRIME rates.[14] PG&E proposed its E-ELEC rate in its current GRC Phase 2 case (A. 19-11-019); other parties including SEIA and the Public Advocates Office (PAO) have served testimony on E-ELEC, and settlement discussions are ongoing. Pursuant to a settlement filed in SDG&E's current GRC Phase 2 case (A. 19-03-002), on September 1, 2021, SDG&E will be filing an application for approval of a new residential electrification rate. SDG&E has several untiered residential rates with significant on-to-off-peak rate differences – DR-SES and EV-TOU-5 – that are possible models for this rate, although these rates are not currently available to all residential customers.[15] If there is a delay in the approval of an electrification rate for SDG&E, we propose that DR-SES and EV-TOU-5 should be made available to NEM 3.0 customers.

Table 6: *Residential Electrification Rates for NEM 3.0 Customers*

Utility	Rate	Status
PG&E	EV2	Available, limits the number of storage customers
	E-ELEC	Proposed in A. 19-11-019
SCE	TOU-D 4p-9p, 5p-8p	Available
	TOU-D-PRIME	Available
SDG&E	Electrification rate	Ordered in D. 20-02-003. Rate is proposed to be filed September 1, 2021
	DR-SES	Applicable to solar customers, currently closed
	EV-TOU-5	Available to customers with EVs

As the table shows, we propose to include SCE's default residential TOU rate, TOU-D 4p-9p and 5p-8p, as among the rates that NEM 3.0 customers can use. Unlike the "TOU-lite" default TOU rates of PG&E and SDG&E, SCE's default TOU rate has much larger differences

14 See D. 20-03-003, at pp. 43-44.

15 DR-SES is a rate for residential solar customers that is now closed. EV-TOU-5 is available to residential customers with electric vehicles (EVs).

between on- and off-peak rates, differences that are closer to SCE's marginal costs.[16] Moreover, the analysis we presented above shows that the use of SCE's default TOU rate in the NEM 3.0 program, with the stepdown proposed in export rates, will be cost-effective by 2027.

The EV2 and TOU-D-PRIME rates that are already in place include eligibility restrictions that do not include solar-only systems, and EV2 limits the availability of the rate to no more than 30,000 customers with storage.[17] Given that the use of these rates would improve the cost-effectiveness of solar-only systems, to the benefit of non-participating ratepayers, SEIA and Vote Solar propose, effective when the NEM 3.0 program begins in 2023, to open these rates to NEM 3.0 customers who install solar systems, as well as to customers with the other types of DERs (storage, electric heat pumps, and EVs) that these rates already target.

4. Incorporation of other types of DERs

The best way for the Commission to ensure that the NEM 3.0 program also accommodates other types of DERs is to base the program on a TOU rate platform that is not solar- or NEM-specific, but that can accommodate the full range of DERs that customers will adopt as the state pursues broad-based electrification measures. This is why SEIA and Vote Solar have proposed the use of a residential electrification rate as a key element of the NEM 3.0 program for general market customers. Customer-sited solar is just one kind of DER. Electric customers increasingly will adopt multiple types of DER – solar, storage, electric vehicles (EVs), heat pumps for water and space heating, and smart thermostats – in multiple combinations of these new technologies. And this list includes only the types of DERs becoming widely available today. Customer adoption of this multiplicity of DERs will be critical to the electrified economy necessary to meet California's long-term climate goals.

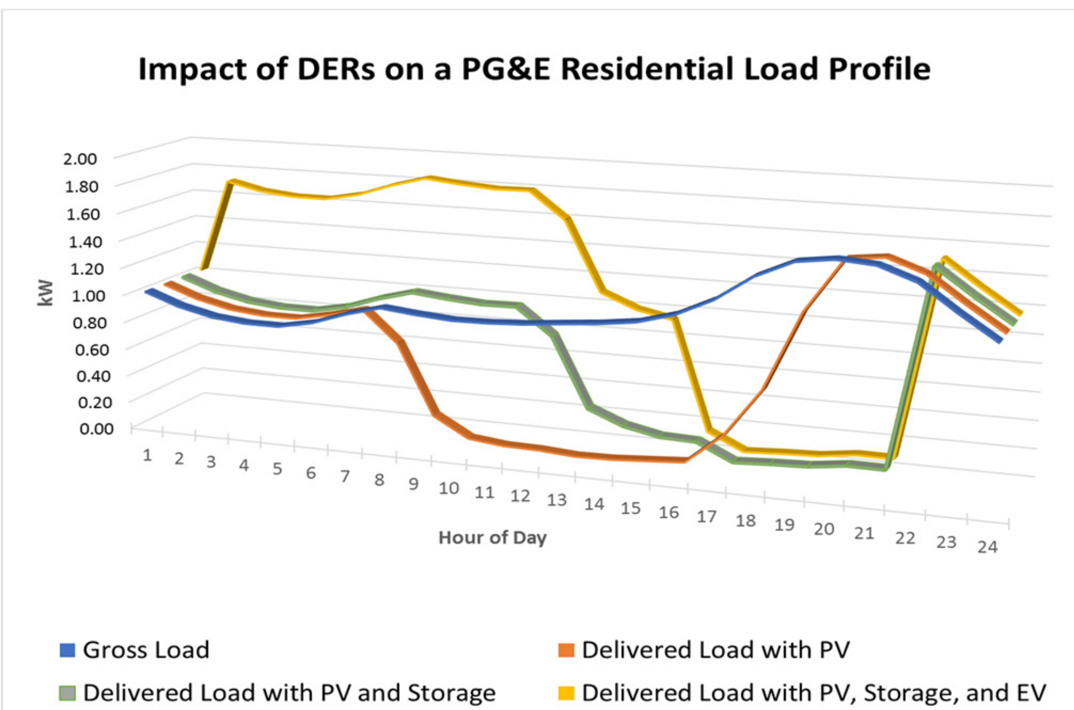
16 SCE's current TOU rate differences (on-peak vs. off-peak in summer, and mid-peak vs. off-peak in winter) for schedule TOU-D 4p-9p are 15.5 and 8.8 cents/kWh, respectively. In contrast, SDG&E's schedule TOU-DR rates have on-peak / off-peak differences of 4.9 cents/kWh in summer and 0.8 cents/kWh in winter; PG&E's peak period rates for schedule E-TOU-C are higher than off peak rates by 6.3 cents/kWh in summer and by 1.7 cents/kWh in winter. See PG&E Advice Letter E-6004, at Table 4. PG&E's testimony in its current 2020 GRC Phase 2 case (A. 19-11-019) proposes to increase these differentials by 2.0 cents/kWh in the summer and 1.1 cent/kWh in the winter, respectively. The testimony notes that PG&E's on-to-off-peak marginal cost differences are 21.9 cents/kWh in summer and 4.6 cents/kWh in winter. See Table 3-7 of Exhibit PG&E-3 in A. 19-11-019.

17 See the SCE TOU-D tariff, Special Condition 5; PG&E EV2 tariff, Special Condition 8.

If customer adoption of multiple types of DERs is to be encouraged, it will not be useful to segregate utility customers into groups based on whether or not they adopt a single type of DER (solar) – i.e. into NEM and non-NEM customers – or to adopt rates specific to a single type of DER. Many of the DER technologies can have as significant an impact on a customer's load profile as adopting solar. **Figure 5** below shows four distinct and different residential load profiles that illustrate how a single residential customer's load profile for delivered energy can change as the customer adopts three different DER technologies in succession.[18] The four profiles are:

1. **Blue:** PG&E residential customer using 10,000 kWh per year with no DERs
2. **Orange:** the customer adds solar with output equal to 90% of the annual load.
3. **Green:** customer adds 11 kWh of battery storage; storage is charged during solar production hours, and discharged in the 4 p.m. to 9 p.m. peak period.
4. **Yellow:** customer buys an EV using 4,000 kWh per year. EV is charged between 2 a.m. and 3 p.m.

Figure 5



[18] The second, third, and fourth types of DER customer have on-site solar production that exports power to the grid in certain hours. The second solar-only profile exports in the midday hours; the third and fourth profiles use on-site storage to shift exports into the peak evening hours. Figure 5 does not show these exports.

One could design four different rates for each of the different combinations of DERs shown in Figure 5. But that would require a further proliferation of additional rates for other types of DERs (for example, for heat pump customers who use electricity for water or space heating), as well as rates for different combinations of these DERs. The IOUs' electric rates are already complex, and the number of specific rates and rate options has mushroomed in recent years. Going down the path of proliferating DER-specific rates will not advance the Commission's important rate design principle that rates should be stable and understandable.[19] This path of multiple rate options makes little sense in an electrifying world in which a key policy goal is to encourage customers to adopt many types and combinations of DERs.[20] Instead, the Commission should focus on implementing a few basic time-of-use rate designs based on the marginal costs for broad customer classes. In order to advance the Commission's rate design principles, these designs should be relatively simple, readily understood, and usable by a wide range of DER customers.

5. Continued application of secondary customer benefits

The Commission should continue for NEM 3.0 customers the existing exemptions from departing load charges, standby charges, and interconnection upgrade costs. Looking first at departing load charges, customers who install DERs such as solar are not departing from the grid – most such customers continue to take and to pay retail rates for significant amounts of delivered power from the grid, even if they reduce their takes from the grid compared to their usage before investing in the DER. If a DER customer takes generation service from a CCA, the customer will pay the normal departing load charges associated with the generation service received from the CCA. With respect to standby charges, the purpose of these charges is to reimburse the utility for costs that the utility may incur if the customer's onsite generation is out of service. Residential solar systems are very reliable; outages are infrequent and unlikely to be

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19 See D. 15-07-001, at p. 28, listing the Commission's rate design principles. Principle No. 6 is "Rates should be stable and understandable and provide customer choice."

20 The Commission has established a few DER-specific rates, for example, Option R rates for commercial solar customers. These rates feature reduced demand charges and a greater reliance on TOU volumetric rates. However, in Phase 2 general rate cases, the Commission has moved toward making Option R rates available either to all customers or to a broader range of DERs including storage and other load-shifting technologies. See D. 18-11-027, at pp. 35-39, which created Option E rates for SCE's large C&I customers who install a range of DERs.

concentrated on a single circuit. The load added to the system from the outage of an individual system is small. As a result, outages of residential solar systems are unlikely to cause changes in loads that differ markedly from normal load fluctuations or that impose significant costs on the utility. Accordingly, the current exemption from standby charges should continue. Finally, although the IOUs have incurred small amounts of distribution upgrade costs associated with net metered solar systems, these upgrades also can provide capacity for other types of DERs, such as EVs and electric heat pumps, that build loads and provide incremental revenue. These costs should continue to be borne by all customers, because all customers will benefit from a more robust distribution system that can allow customers to use DERs of all types.

6. Terms of service and billing rules

SEIA and Vote Solar propose three important change to the terms of service and billing rules for net metered systems.

Net surplus compensation. The current NEM program includes compensation for "net surplus" kilowatt-hours, which are the kilowatt-hours produced by a customer's PV system, on an annual basis, in excess of the customer's annual usage. The Commission has not re-visited the level of net surplus compensation (NSC) since the program was created in 2011 in D. 11-06-016. Net surplus kWhs are compensated at the applicable 12-month rolling simple average default load aggregation price (DLAP) from the CAISO energy market in the daylight hours of 7 a.m. to 5 p.m.[21] For each NSC customer, the rate is set using the 12 months of CAISO DLAP prices corresponding to the customer's annual true-up period.

When the NSC rate was created in 2011, the IOUs expected to purchase only small amounts of net surplus power from NEM customers. For example, in 2009 the three IOUs estimated that their NEM customers produced about 12 million kWh of net surplus power.[22] In D. 11-06-016, the Commission declined even to apply a solar generation profile to DLAP prices in calculating the NSC rate, stating that "[t]he cost of calculating market prices with more specificity would likely outweigh the value of the program."[23] At that time, PG&E had about

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[21] See D. 11-06-016, at Ordering Paragraph 1.
[22] *Ibid*., at p. 28, footnote 21.
[23] *Ibid*.

25,000 NEM customers.[24] Today, PG&E has 508,000 NEM customers, and based on discovery responses in this case, the NEM customers of the three IOUs produce 427 million kWh per year of net surplus generation. This is no longer a small, incidental amount of renewable generation – it is equal to the annual output of 271 MW of solar generation operating at a typical 18% capacity factor. Net surplus power is about 2.5% of all NEM output, and about 3% of residential NEM kWhs. This data is presented in **Table 7**.[25]

Table 7: *Current Data on Net Surplus Generation*

Utility	Rate Class	NSC Energy *MWh*	NSC Capacity *MW at 18% c.f.*	NEM Capacity *MW*	NSC as % of NEM
PG&E	Residential	157,568	99.9	3,008	3.3%
	Non-residential	33,845	21.5	561	3.8%
SCE	Residential	83,536	53.0	3,336	1.6%
	Non-residential	25,398	16.1	2,351	0.7%
SDG&E	Residential	105,747	67.1	1,073	6.2%
	Non-residential	21,167	13.4	284	4.7%
All IOUs	Residential	346,850	220.0	7,417	3.0%
	Non-residential	80,410	51.0	3,196	1.6%
	Total	427,260	271.0	10,613	2.5%

In addition, NEM 2.0 customers appear to be producing more net surplus generation than NEM 1.0 customers. Data provided by PG&E shows that 6.8% of NEM 2.0 generation is net surplus, compared to just 2.7% of NEM 1.0 output.[26]

The standard for the NSC rate is set forth in P.U. Code Sections 2827 (h)(4)(A)and (B):

> The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected. The ratemaking authority shall determine whether the compensation will include, where appropriate justification exists, either or both of the following components:
>
> (i) The value of the electricity itself.
>
> (ii) The value of the renewable attributes of the electricity.

Net surplus kWhs constitute a non-trivial share, about 5%, of all NEM exports to the grid.[27] Indeed, it is impossible to distinguish whether an exported kWh is surplus or not at the time it is

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24 *Ibid*.
25 The data in this table is from IOU responses to SEIA/Vote Solar Data Request (DR) No. 1, Q7.
26 *Ibid*.

produced; customers only know that they have net surplus kWh after annual output is compared to annual usage. Because net surplus kWhs cannot be distinguished from regular NEM exports, it is reasonable to value net surplus kWhs using the 2020 ACC in the same manner as all other NEM exports, and to assume that the hourly output profile of net surplus kWhs is the same as the hourly profile of NEM exports. The approved ACC captures the "value of the electricity" to the utility, in terms of the costs that the utility will avoid by accepting the net surplus kWhs in lieu of other generation. Further, because the 2020 ACC is based largely on the cost of avoiding additional procurement of renewables, as modeled in the IRP's No New DER case, the ACC also captures "the value of the renewable attributes of the electricity." To determine the NSC rates that should apply to net surplus kWhs from residential customers in 2023 when NEM 3.0 commences, we have applied the hourly avoided costs for 2023 to typical export profiles from residential solar customers of the three IOUs. The result is the NSC rates shown in the center column of **Table 8**, which SEIA and Vote Solar recommend should be adopted for any NEM 3.0 customers whose annual billing period is calendar year 2023. For comparison, the final column of the table shows the current NSC rates for the three IOUs for calendar 2020, based on the 7 a.m. to 5 p.m. IOU DLAP prices for that year. The utilities should use a 12-month rolling average of the adopted ACC values as the new NSC rate for NEM 3.0 customers, replacing the current use of a 12-month rolling average of DLAP prices.

Table 8: *Proposed 2023 NSC compensation rates – Residential*

Utility	Proposed Residential NSC Rate *($/kWh)*	2020 NSC Rate – IOU DLAPs *($/kWh)*
PG&E	0.0632	0.0259
SCE	0.0585	0.0264
SDG&E	0.0577	0.0283

Sizing of systems. As residential customers electrify, their electric use will increase – often significantly as customers displace natural gas and gasoline with electricity to power heat pumps and EVs. This will lead to an increasing number of situations where customers will want to oversize their solar systems in anticipation of buying an EV or heat pump in a few years when the customer's current car or water heater will reach the end of their life. Customers cannot be

[27] About one-half of NEM generation is exported; net surplus kWh are 2.5% of NEM generation; and by definition net surplus kWh are exported.

expected to electrify completely at one time, given the significant capital expense required for new DER technologies. Accordingly, NEM 3.0 customers should be allowed to oversize their solar systems by up to 50%, with the excess output compensated at the avoided cost-based NSC rate proposed above.[28] The 50% allowance is based on a residential customer with usage of 10,000 kWh per year adding an EV and an efficient electric water heater, both of which can be fueled primarily with off-peak solar electricity.[29] Even if some over-sizing does occur due to the time requirements for consumers to electrify, our proposed NSC rate will result in the IOUs obtaining additional renewable generation at an avoided cost price to which other ratepayers will be indifferent.

Monthly billing as the default. The current default process of annual billing with one annual true-up works well for NEM customers with larger systems relative to their usage; these customers accumulate bill credits in some months that offset net usage in others, resulting in a relatively small annual true-up bill. However, many residential customers with smaller systems relative to their usage are surprised by a big true-up bill at the end of the year. We propose to change to monthly billing as the default process for residential and small commercial customers, with an annual true-up in April. These customers would retain the choice of annual billing with an annual true-up.

No other changes. Otherwise, we propose no changes to the proven, well-established terms of net metering service. These include:

- Continuing the certainty that a customer who invests in distributed solar under the current net metering tariff will be able to take service under the same tariff for a period of 20 years. This is the same assurance that the Commission provided to NEM 1.0 and 2.0 customers in D. 14-03-041 and D. 16-01-044, respectively. Distributed solar and storage systems represent long-term investments of customers' private capital in new clean energy infrastructure. Customers make these investments in reliance on the

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28 P.U. Code Section 2827(b)(4)(A) defines an "eligible customer-generator" who qualifies for NEM as one whose on-site renewable generation "is intended primarily to offset part or all of the customer's own electrical requirements." Even if a customer oversizes their system by 50%, the output still will be primarily intended to offset the customer's load, with at least two-thirds of the output going toward that purpose.

29 Connecticut recently developed a new net metering program that includes this concept. Connecticut allows residential NEM systems to be sized to the customer's highest historical load over the last five years, plus a reasonable approximation of the load of two EVs. Customers without electric heat can also add the electric load associated with fuel switching to electricity. See the Connecticut Public Utilities Regulatory Authority order dated February 10, 2021 in Docket No. 20-07-01, at pp. 16-17.

current rules for compensating their exports of excess power to the grid, and they rely on the Commission to provide for the long-term stability in those rules as a basic matter of consumer protection.

- Netting of imported and exported power in each metered interval, as established in D. 16-01-044 and affirmed on rehearing in D. 19-04-019.
- The same NBCs removed from export rates under NEM 2.0 should continue to be excluded from export rates under NEM 3.0.
- Continuation of the $10 per month minimum bill.

7. Smart inverter requirements

SEIA and Vote Solar do not propose new smart inverter requirements, beyond those that are in place today under Rule 21.

8. Grid services

The growth of solar-plus-storage systems will open new opportunities for these resources to provide a variety of grid services. SEIA and Vote Solar strongly encourage the Commission to continue and expand the ongoing work to develop these services. One example of these efforts is the new pilot grid services tariff that the Commission recently approved in D. 21-02-006. There is also ongoing work in Track 4 of the Resource Adequacy proceeding directed at developing the means for aggregated behind-the-meter (BTM) resources to participate in RA markets. The transition away from traditional NEM to net billing will require substantial investment in storage as well as solar. Developing new opportunities for storage to provide innovative grid services will be an important means to support these investments and to provide additional value to the electric system.

9. Safety issues

SEIA and Vote Solar do not believe that there are any new safety concerns raised by our proposal. We support the continuation and improvement, as necessary, to the existing safety-related provisions of the Commission's interconnection rules, through the existing Rule 21 process.

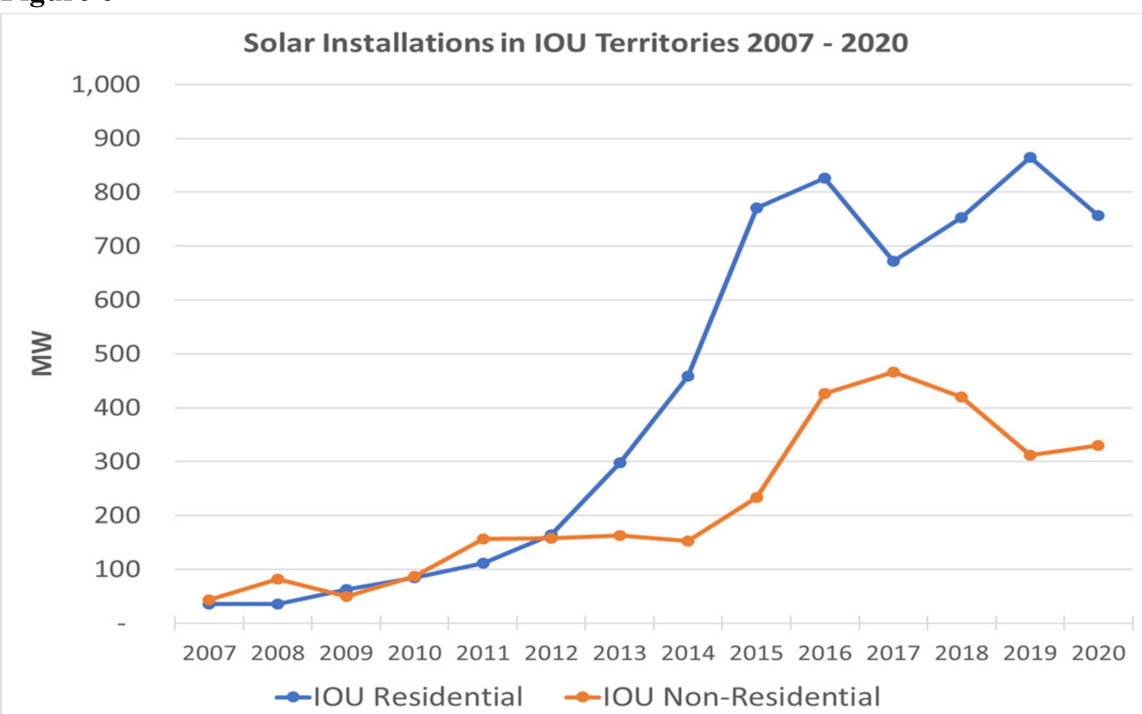
10. Legal issues

SEIA and Vote Solar do not believe that our proposal raises new legal or tax issues, as our proposal retains significant elements of the NEM 2.0 structure, with new requirements for residential customers to use certain TOU rate schedules and with reduced compensation for the power that residential customers export to the grid. We discuss consistency with other Commission decisions and the statutory requirements of Public Utilities Code Section 2827.1 in Section III below.

B. Non-residential, Commercial & Industrial (C&I) General Market Tariff

The deployment of solar in the non-residential sector, by commercial, industrial, and institutional customers of the IOUs, has declined markedly since NEM 2.0 was implemented in 2017, declining by about one-third from the peak year of installations in 2017, as shown in the figure below.[30] At the same time, residential installations have remained relatively steady over the last five years (2016-2020).

Figure 6



[30] The source for Figure 6 is the California Distributed Generation Statistics website and database of interconnected projects, at https://www.californiadgstats.ca.gov/downloads/.

The NEM 2.0 Lookback study shows that the cost-effectiveness of solar in the non-residential market is not the focus of concern today. The study states that non-residential distributed solar in the commercial, agricultural, and industrial sectors generally passes the Total Resource Cost test. Further, from a cost-of-service perspective, after installing solar, non-residential customers continue to pay rates that fully cover their costs.[31] Non-residential solar customers take service on the IOUs' C&I rates that often include significant demand charges that solar customers are unlikely to be able to reduce significantly. Finally, and most important, the movement in the last several years to the later 4p-9p on-peak period has reduced the bill savings available to non-residential customers from solar-only systems, given the generally lower TOU volumetric rates in C&I rates. The non-residential market may recover over the next several years as storage systems fall in cost and become more widely used, allowing C&I customers to shift solar output into the evening peak period. However, given this recent slowdown in the non-residential market, the Commission should not take further steps in this proceeding to reduce the compensation for exports from C&I solar. The non-residential market should remain under the current NEM 2.0 rules.

IV. CONFORMANCE WITH GUIDING PRINCIPLES

In Decision 21-02-007, the Commission adopted eight guiding principles to assist in the development and evaluation of proposals for a successor to the current net energy metering tariff. The proposal advanced by SEIA and Vote Solar conforms with each of these principles.

1. A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1.

There are four primary policy principles embedded in Public Utilities Code Section 2827.1 to which a NEM successor tariff must adhere:

(a) Ensures that customer-sited renewable distributed generation continues to grow sustainably;

[31] See the Lookback Study, at p. 98. Table 5-11 shows that non-residential NEM customers pay more than their cost of service (i.e. 152% for PG&E, 108% for SCE, and 166% for SDG&E).

(b) Includes specific alternatives designed for growth among residential customers in disadvantaged communities;

(c) Ensures that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility; and

(d) Ensures that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs.

The SEIA / Vote Solar proposal satisfies each of these statutory principles.

a. Sustainability

The legislative history,[32] prior Commission decisions,[33] and basic precepts of statutory construction[34] all lead to the conclusion that the statutory language "grow sustainably" refers to examining any proposed change to the tariff in light of its impact on the growth of the customer-sited renewable DG market. This language does not refer to the impact of the tariff on non-participating customers, which is addressed elsewhere in the statute. The SEIA/ Vote Solar proposal is tailored to promote the continued growth of the residential market for renewable DG by utilizing a glide path from the current compensation of exports at the full retail rate to compensation at a level consistent with the IOUs' avoided costs, as measured on a long-term, life-cycle basis. The need for such glide path was recognized by the Commission's consultant E3, in its white paper's analysis of various frameworks pursuant to which a successor tariff could

32 Assembly Committee on Utilities and Commerce, Bill Analysis of AB 327 (Perea) – As Amended: September 6, 2013, available at http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_cfa_20130911_131650_asm_comm. This is the AB 327 bill analysis that informed legislators when they voted to approve this language; it refers to "whether the changes to NEM will impact the sustained growth of the industry" and noted several matters that impact "sustainable growth" in addition to NEM, such as federal tax credits, treatment of depreciation, and customer credits for greenhouse gas reduction – i.e.,. factors that impact the customer economics of investing in DERs and thus the growth of the market.

33 *See, e.g., D. 16-01-044,* p. 53 (noting that looking at average growth over a 3-5 year period should be sufficient to function as a way for Energy Division staff, IOUs, and market participants to evaluate whether a major change in the tariff should be considered).

34 *See Donovan v. Poway Unified School Dist.,* 167 Cal. App. 4th 567, 590-591 (citations omitted) (emphasis added) ("In interpreting a statute, 'we strive to give effect and significance to every word and phrase.' We 'give the words of a statute their ordinary and usual meaning and construe them in the context of the statute as a whole.*' We 'must presume that the Legislature intended 'every word, phrase and provision … in a statute … to have meaning and to perform a useful function.*'")

operate. Indeed, E3 determined that the absence of such a glide path would endanger California's ability to maintain a viable customer-sited renewable generation industry.[35]

b. Growth in Disadvantaged Communities

The SEIA / Vote Solar Proposal is a general market proposal, not directed toward lower-income residential customers. However, Vote Solar, along with GRID Alternatives and the Sierra Club (the "Joint Parties"), are advancing a separate proposal crafted to increase access to distributed generation by environmental justice and social justice (ESJ) communities. SEIA supports this separate proposal. Specifically, SEIA supports the Joint Parties' proposal to decouple the savings on the NEM exports of qualifying low-income customers from their effective underlying retail rate, and to assign them a time-varying rate for their exports that is equal to the *current* default residential TOU rate offered by the customer's IOU in 2021. This proposal is critical to providing CARE customers with an adequate incentive to install on-site clean energy options. By providing CARE customers with a higher value for their exports (replacing the reduced value that results from the CARE discount), this proposal will boost their clean DG savings and reduce their energy burden to a greater degree than is provided under the current NEM structure. SEIA also supports not requiring qualifying low-income customers to take service under an electrification rate, because it is important to avoid reductions to low-income customers' NEM bill savings, and low-income customers will have fewer financial resources for electrifying their homes.

Moreover, SEIA and Vote Solar are aware that other parties will be presenting proposals to enhance access to DG in disadvantaged communities. These proposals should be reviewed for potential adoption in conjunction with our general market proposal.

c. Costs and Benefits of the Renewable Electrical Generation Facility

The plain statutory language of Section 2827.1(b)(3) requires the Commission to "ensure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility." The logical interpretation of this statute is that the Commission must consider the cost-effectiveness tests from the *Standard Practice Manual* (*SPM*) that include the costs and benefits of the customer's renewable DG

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[35] *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California Successor Tariff Options Compliant with AB 327*, E3 (January 28, 2021), at p. 3; hereafter, "E3 White Paper."

facility. There are two tests that include the costs of the DG facility – the Total Resource Cost (TRC) test and the Participant Cost Test (PCT).

The TRC test considers whether the benefits of the DG facility as a new resource for the electric system exceed the costs of the facility. The Commission has determined that the TRC test is the principal test to be used to evaluate the cost-effectiveness of demand-side resources. As discussed above, distributed solar and solar-plus-storage resources will pass the TRC going forward, and thus are cost-effective resources for electric customers in the IOU service territories.

The PCT examines the costs and benefits that the participant customer realizes from their choice to install a DG facility, and is consistent with the sustainability requirement in Section 2827.1(b)(1). If the NEM 3.0 tariff creates for a participant an adequate margin of benefits over costs, then renewable DG will continue to grow in a way that can be sustained over time. SEIA and Vote Solar have analyzed the PCT results under our proposed tariff, using, on the cost side, the system LCOEs from in Table 2 above and, for the benefits, the bill savings shown in Figures 2 to 4 above. **Table 9** summarizes the PCT results from 2023-2030, for the blended portfolio of solar and solar-plus-storage resources installed in each year.

Table 9: *PCT Results*

Year	Utility			Weighted Average
	PG&E	SCE	SDG&E	
2023	1.75	1.73	1.97	1.78
2024	1.40	1.36	1.55	1.41
2025	1.41	1.39	1.56	1.43
2026	1.38	1.42	1.52	1.42
2027	1.29	1.43	1.42	1.36
2028	1.38	1.50	1.51	1.44
2029	1.42	1.52	1.54	1.47
2030	1.48	1.56	1.60	1.53

Notably, these PCT results are lower than those reported in the Lookback Study for PG&E and SDG&E.[36] It will be challenging for the industry to sustain growth with this decline in participant economics. The period from 2023 to 2030 also includes the decline to zero in 2024 of the federal ITC for residential solar customers, a change which will have significantly increase the cost of these systems. Moreover, the Commission should recognize that customer paybacks

[36] See NEM 2.0 Lookback Study, at Table 1-2.

will be longer for systems that include storage, as the result of the additional capital costs for the storage capacity and associated controls. We calculate that, in 2024 after the ITC expires, simple paybacks will average 8 years for solar-only, but over 10 years for solar-plus-storage. We expect customers to move to systems with storage for the resiliency benefit of a source of backup power and to manage more challenging TOU rate structures, but it will be a difficult transition for the industry to manage.

d. Total benefits of the tariff to all customers and the electrical system approximately equal total costs

Section 2827.1(b)(4) requires the Commission to review the standard tariff/contract from the broader perspective of <u>all</u> customers. The only *SPM* tests that consider costs and benefits to <u>all</u> customers in a single test are the TRC and the Societal Tests (which adds societal benefits to the TRC). However, SEIA and Vote Solar recognize that, within the group of all ratepayers, participating and non-participating customers can have different perspectives (as revealed by the PCT for participants and the RIM test for non-participants). Collectively, we recognize the importance of providing for an equitable balance between the interests of participants and non-participants. Moreover, it is this balance between participants and non-participants that is impacted by any change to the compensation structure for net metered systems. However, we emphasize that this is a matter of equity that is impacted by other considerations beyond the precise score on a stringent RIM test. There are other considerations that the Commission must weigh in considering this equitable balance of interests:

- California needs the clean generation that distributed solar provides – a resource that is cost-effective as a new resource for the system as a whole. The IRP modeling indicates that there would be significant land use constraints if the state tried to replace all demand-side resources with utility-scale, supply-side renewables. These constraints are discussed in more detail in **Attachment A**. Further, we calculate that the growth of solar-plus-storage systems will provide important additional firm capacity available to serve the evening net load peak to the CAISO system over the coming decade. We project that this growth will add 4,600 MW of additional storage capacity by 2030.

- There are substantial quantifiable societal benefits from distributed solar. Some of these benefits are specific to distributed renewables, and are not provided by utility-scale renewables. These include enhanced land use and local economic benefits. These societal benefits accrue to all ratepayers, including non-participants. As the RIM test is a measure of equity for non-participants, the Commission should weigh these benefits in its assessment of the impacts on non-participants. Further discussion and quantification of these benefits will be presented in our testimony.

- DER policy in California has not considered the RIM test for energy efficiency technologies that reduce a customer's consumption behind the meter. This is also true nationally.[37] To be consistent and to treat all DER technologies equitably, the RIM test for solar and solar-plus-storage could focus only on the power that is exported to the grid. If we had taken this approach, our general market tariff would be cost-effective for non-participants even before 2027. SEIA and Vote Solar understand that the California Solar & Storage Association (CalSSA) will be presenting this perspective in their NEM 3.0 proposal.

- It is important to recognize the stringency of the RIM test, which essentially would hold non-participating ratepayers harmless from any impacts of other customers installing solar or solar-plus-storage systems, including the impacts of other customers serving their own loads behind the meter with on-site generation that never touches the grid. The RIM test sometimes is called the "No Losers" test because, if a program passes the RIM test, then all parties will benefit from the program. The founder of the Rocky Mountain Institute, Amory Lovins, has commented that the RIM test really should be called the "Hardly Any Winners" test, because having to ensure that there are zero impacts on non-participants from a demand-side program means that few such programs will be implemented, even if the overall system benefits are positive.[38] The stringency of the RIM test is an important reason why it is not used for other demand-side programs.

- Any inequity revealed by the RIM test can be addressed by ensuring that all ratepayers have reasonable access to DERs or similar programs. Vote Solar and SEIA strongly recommend that this proceeding should focus on developing a successor tariff with a major equity component that can make more substantial progress toward providing all Californians with the environmental and economic opportunity to install or to use solar and storage where they live.

Considering all of these factors, SEIA and Vote Solar submit that it is reasonable and equitable for the NEM 3.0 tariff to be designed to improve the RIM score over time through the use of electrification rates and a measured step-down in export compensation, as we have proposed.

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37 See Kushler, Nowak, & Witte, *A national survey of state policies and practices for the evaluation of ratepayer-funded energy efficiency programs* (February 2012), ACEEE Report Number U122. Available at https://www.aceee.org/sites/default/files/publications/researchreports/u122.pdf.

38 See *The Electricity Journal* 33 (2020), at 106827.

2. A successor to the net energy metering tariff should ensure equity among customers.

The concept of equity within a NEM tariff does not mandate that all customers be treated exactly the same. Instead, equity denotes fairness. Different circumstances may dictate that certain groups of individuals be treated differently under the successor NEM tariff, if it is fair to do such. As discussed above, SEIA and Vote Solar strongly support taking additional measures, in concert with this general market proposal, to enhance access to distributed solar for low income customers and disadvantaged communities. We also have designed our successor tariff to address equity between participating and non-participating customers, as discussed above.

3. A successor to the net energy metering tariff should enhance consumer protection measures for customer generators providing net energy metering services.

The Commission has recognized that, in the context of establishing a NEM tariff, consumer protection mandates that customers "have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG system."[39] The SEIA/Vote Solar proposal recognizes this mandate by providing that a system installed in a certain year will retain its year-specific NEM 3.0 structure, including the specified export percentage, for 20 years.

Similarly, SEIA and Vote Solar continue to support the Commission's existing policy that customers under the NEM 1.0 and NEM 2.0 tariffs should be allowed to stay on those tariffs, with their respective export compensation mechanisms, for twenty years from the date of the interconnection of their solar installation. Failure to fulfill the promise of stability of the NEM structure under which more than one million California ratepayers have invested in a solar installation will evoke a consumer protection maelstrom – one which would be the product of the

[39] See Decision 16-01-044, at pp. 100-101; Decision 14-03-041, at pp. 20-25: "We are cognizant of the legislature's direction that we consider the reasonable payback period in setting the transition timeframe, and are persuaded that customers who invest in renewable distributed generation systems and participate in existing NEM tariffs should at least have an opportunity to recoup their initial investment in distributed renewable generation. In addition, we find that adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation."

Commission's own doing.[40] Indeed, the Commission has adopted standardized inputs and assumptions that solar providers are required to use to calculate estimated electric utility bill savings from a solar energy system that a residential consumer can reasonably expect during the first 20 years following interconnection of the system.[41] Changing the export rate compensation for current NEM customers will upend the bill savings estimate with which these customers were presented when deciding to buy a solar system. In essence the Commission would be inflicting a "bait and switch" on current NEM customers – the antithesis of consumer protection.

4. A successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1.

The SEIA / Vote Solar proposal does not preclude participation in the successor tariff by any of the technologies that meet the definition of renewable electric generation facility under PU Code Section 2827.1.

5. A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18.

The energy policies delineated in this principle are all crafted to facilitate California's overarching objective of economy-wide decarbonization. In reviewing each proposal for a successor NEM tariff, the Commission must determine whether the proposal works in concert with these existing policies and programs to advance this objective or will interfere with their workings in manner which will impede their progress. The SEIA /Vote Solar proposal will work to enable California' energy goals rather than hindering their realization.

a. Electrification

As illustrated in the *Net Energy Metering 2.0 Lookback Study*, NEM has become a foundational facilitator of electrification. The study illustrates that customers in PG&E's and SDG&E's service territories increased their electric usage by approximately 30% after adding

[40] We include as **Attachment C** a narrative history of the turmoil that occurred in Nevada in 2014-2015 when the Public Utilities Commission of Nevada changed the net metering rules and substantially reduced the compensation for 25,000 existing NEM customers of NV Energy.

[41] *See* Decision 20-08-001.

solar.[42] As confirmed by the study, a customer's investment in a solar system is often the precursor and catalyst for their adoption of other types of DERs such as electric vehicles and electric appliances.[43] The process of adding solar contributes to customers' education about other electrification technologies that can reduce their carbon footprint and save them money. Customers also recognize that the ability to produce at least a portion of your electricity on-site will be critical in a world in which electricity will constitute an increasing share of primary energy use. Finally, the savings from producing your own electricity on-site are an important means for customers to manage their energy bills in a state with a high electric rates and a high cost of living.

In order to support and facilitate this trend toward beneficial electrification, California must maintain a viable customer-sited renewable generation industry. This will not be accomplished if radical changes in the NEM tariff strip Californians of the ability to secure a reasoned return on their investment in renewable DG. In this regard, the SEIA and Vote Solar have proposed a reasoned step down of the export compensation under the NEM 3.0 general market tariff to ensure a reasonable payback period on the customer's private investment. In addition, the SEIA/Vote Solar proposal requires PG&E and SDG&E customers under the new successor tariff to take service under a rate designed to incent electrification.[44] The combination of these two factors should not only continue the trend towards electrification by NEM customers, but should accelerate it.

b. Integrated Resource Planning Process

The SEIA / Vote Solar proposal uses the 2020 ACC as the principal source for the avoided cost benefits of renewable DG for evaluating the cost-effectiveness of our proposed tariff. This brings the NEM 3.0 tariff into alignment with the Commission's IRP planning process. In D. 20-04-010, the Commission restructured the 2020 ACC to include key metrics from the IRP modeling used to develop the IRP's current Reference System Plan (RSP). Most important, the 2020 ACC uses metrics from a No New DER case in which all of the demand-side

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42 *Net Energy Metering 2.0 Lookback Study*, Verdant Associates, LLC (Jan. 21, 2021), Table 3-1.

43 *Id.,* p. 62.

44 In SCE's service territory, the SEIA and Vote Solar proposal recommends that residential NEM 3.0 customers should be allowed to continue to take service on the default TOU rate schedule, as that rate has significant differentials between on-peak and off-peak periods, comparable to those on an electrification rate.

resources included in the RSP are removed, and the case is re-run to replace those demand-side resources with additional supply-side generation. Thus, the 2020 ACC values DERs based on the costs of the supply-side resources that would be needed to replace them in the adopted RSP. As a result, if a renewable DG resource is cost-effective using the 2020 ACC, that customer-generation will be less costly than supply-side resources. This use of the No New DER case in the 2020 ACC is an important step toward the Commission's longstanding goal of integrated planning for both demand- and supply-side resources.[45]

c. Title 24 Solar Mandate

Finally, as indicated in the principle, the Commission must be cognizant of the impact that changes in the current NEM structure could have on the "solar mandate" implemented through changes to Title 24, Part 6 of the state's Building Energy Efficiency Standards, requiring solar on all new home construction. In crafting new building standards, the California Energy Commission ("CEC") is required to show a cost savings over the course of a 30-year mortgage. While the CEC was able to make this showing at the time that the regulations were adopted, there was an acknowledgement that changes to NEM tariff could have a big effect on the cost/benefit equation for customers. While it was determined that a reasonable level of net metering reform would maintain the cost effectiveness, more severe reforms would not.[46] The SEIA / Vote Solar proposal is crafted to maintain a judicious level of reform to ensure that the solar mandate remains cost effective as the costs of solar installations continue to decline.

6. A successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities.

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45 See D. 20-04-010, at p. 37: "Although the No New DER scenario will not actually occur, the outputs of the modeling tells us what it would cost to operate the grid replacing the distributed energy resources with supply-side resources. The outputs provide the Commission with the best estimated value of the distributed energy resources. As noted by SEIA and Vote Solar, the use of the metrics from the No New DER best advances the Commission's long-term goal of integrated resource planning and comparing demand-side resources alongside supply-side resources."

46 *See Building Energy Efficiency Measure Proposal to the California Energy Commission for the 2019 Update to the Title 24, Part 6 Building Energy Efficiency Standards, Rooftop Solare PV*, Prepared by: Energy and Environmental Economics, Inc (September 2017), pp. 44-46. Available at 2019 Energy Code Measure Proposal Reports (ca.gov).

The structure of the SEIA/Vote Solar proposal is designed to be readily understandable to customers of the new successor tariff. The basic premise – a defined percentage off the existing retail rate for exports to the grid - is one which a customer can readily understand. Moreover, the fact that the customer will maintain the same percentage stepdown for twenty years enables a more precise calculation of savings that a customer can expect to receive over the life of their solar installation.

While the SEIA/Vote Solar proposal does not maintain complete consistency among all three IOUs, the differences are necessary given the significant variance in their current rates as well as in the design of their default TOU residential rates. It is well documented that SCE's residential rates are significantly lower than those of PG&E and SDG&E. Therefore, the step down of the SCE retail rate to reach avoided costs does not need to be as precipitous. Similarly, SCE has designed default TOU residential rate differentials between on-peak and off-peak rates that are akin to those in other electrification rates. Finally, we have shown that the SCE residential default rate will be cost-effective under NEM 3.0 after a modest stepdown in export rates, a result similar to our analyses of the electrification rates of PG&E and SDG&E.

7. A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system.

Customer-sited renewable DG will provide maximum value to all customers and to the electrical system if DG output can serve the on-peak period when power is most valuable. A focus of the NEM 3.0 program should be to expand the use of on-site storage that can shift DG output to the peak period. The use of electrification rates with a 4p-9p on-peak period and large on-peak-to-off-peak rate differences is a key step to encourage the growth of solar-plus-storage systems.

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

In explaining the rationale behind this principal, the IOUs opined that any prospective tariff structure should be designed to avoid creating any skewed incentives for customers to change their load serving entity ("LSE"), or for an LSE to decline to adopt an equivalent successor tariff program as the IOUs.[47] SEIA and Vote Solar are not aware of any way in which our proposal would favor generation service from one LSE over another.

V. IMPLEMENTATION PLANS AND TIMELINES

Adoption of the SEIA and Vote Solar proposal will not necessitate a formal implementation phase. Similar to the implementation of the NEM 2.0 tariff, the SEA and Vote Solar proposal can be implemented through an advice letter process. That said, SEIA and Vote Solar submit that implementation of the successor tariff should be undertaken in measured steps to ensure, to the extent possible, a smooth transition.

A. Considerations with Respect to Implementation

When implementing the NEM 2.0 tariff, the Commission directed the IOUs to file advice letters with their respective NEM successor tariffs within 30 days of the Commission decision approving the tariff.[48] This resulted in the IOUs' advice letters being filed at the end of February 2016 and a Commission resolution approving the advice letters, with certain modifications, being adopted at the end of June 2016.[49] However, the tariffs were not to go into effect until the statutory MW cap on the NEM program was reached in each of the IOUs' respective service territories, or July 1, 2017, whichever was earlier.[50] In other words, there was a gap between the time that the industry knew the final Commission-approved terms of the NEM 2.0 tariff, and the time when new NEM customers would be required to take service under that tariff. This gap between approval and customers taking service under the new tariff gave the industry time to make the necessary preparations to offer what was, in essence, a new product. This gap period will be even more crucial for managing the transition to the NEM 3.0 tariff.

The change to the NEM structure made in this proceeding will be more substantial than the one made in the NEM 2.0 proceeding. This degree of change necessitates that the IOUs be provided more time than was afforded with for the NEM 2.0 tariff to submit advice letters based on a NEM 3.0 tariff as approved by the Commission. With additional time, the IOUs can ensure

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47 *Joint Comments of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company on Proposed Guiding Principles*, filed in R. 20-08-020 (December 4, 2020), at pp. 11-12.

48 *See* D. 16-01-044, Ordering Paragraph No. 1.

49 *See* Resolution E-4792 (issued June 23, 2016).

50 *Id.,* p. 31, Ordering Paragraph No. 5.

a complete advice filing, thus mitigating the need for supplemental filings which often slow down the process.

The degree of change in the NEM 3.0 tariff structure will also require that the industry be afforded a reasonable amount of time to train their sales force and customer service representatives on the new structure as well as to make changes to their marketing materials and associated contracts. The Commission itself will need to effect changes to its Solar Consumer Protection Guide to reflect the program modifications.

Moreover, over the last five years, each of the IOUs have argued that they have been unable to undertake Commission-ordered rate design changes in a timely fashion, given ongoing transitions of their billing system platforms. Each of the IOUs have a queue of rate design changes waiting to be made once these transition issues are resolved. It is not clear to SEIA and Vote Solar whether the Commission intends for changes in the NEM structure to jump the queue ahead of previously approved rate design changes, but even if such is the intent, the Commission needs to be assured that the changes have been correctly implemented and there are no hiccups in the roll-out. The change in the NEM structure will have significant impacts on the rooftop solar and storage industry. It should not be further hamstrung by IOU billing system problems.

Finally, specific to the SEIA / Vote Solar proposal is the requirement that customers in the PG&E and SDG&E service territories take service under an electrification rate schedule. While PG&E currently has one such schedule (EV2) and one pending approval in Phase 2 of its current General Rate Case (E-ELEC), SDG&E does not have a residential electrification rate. At present, SDG&E is scheduled to file for approval of such a rate schedule on September 1, 2021 in a rate design window application. Under the Commission's Rate Case Plan, such applications are intended to be processed more expeditiously than general rate cases.[51] Thus, a necessary piece to implement the SEIA and Vote Solar proposal would be not be available in the SDG&E service territory until summer 2022. If there is a delay in the approval of an electrification rate for SDG&E, we propose, as a backup plan, that DR-SES and EV-TOU-5 should be made available to NEM 3.0 customers.

B. Specific Timeline

[51] *See* Decision 07-07-004, Attachment A, p. A-8 (providing a five month schedule for Rate Design Windows proceedings, but historically these proceedings have taken longer)

The proposed schedule in **Table 10** below is based on the considerations set forth in Section V.A above.

Table 10: *Proposed Implementation Schedule*

Event	Date
SDG&E files application for Residential Electrification Rate	September 1, 2021[52]
Commission issues Decision on Successor NEM tariff	November 18, 2021[53]
IOUs file Implementation Advice Letters	February 18, 2022[54]
Protests/Responses on Implementation Advice Letter	March 10, 2022[55]
Commission Draft Resolution on Implementation Advice Letters	June 2022
Protests/ Responses on Implementation Draft Resolution	Late June / Early July 2022[56]
Commission Issuance of Final Implementation Resolution	End of July 2022
Commission Decision on SDG&E Application for Residential Electrification Rate	July/August 2022[57]
Industry undertakes necessary preparations for NEM 3.0 roll out; Commission revises its Consumer Solar Protection Guide; IOUs make necessary billing system changes.	July – December 2022
Effective Date of NEM 3.0 Tariff	January 1, 2023

VI. SIMILARITIES AND DIFFERENCES WITH THE E3 WHITE PAPER

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52 *See Joint Motion for Approval of General Rate Case Phase 2 Settlement Agreement*, A. 19-03-002 (October 8, 2020), Attachment A, Section 2.2.7.2, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286353.PDF.

53 Based on the schedule set for the in the Assigned Commissioner Scoping Memo and Ruling, R. 20-08-020 (November 19, 2020), p. 4.

54 Based on SEIA's and Vote Solar's proposal to afford the IOUs 90 days to submit implementing advice letters.

55 Pursuant to General Order 96-B, Section 7.4.1, twenty days are afforded for responses or protests to advice letters.

56 Pursuant to Commission Rule 14.5, twenty days are afforded for comments on a Draft Resolution.

57 Based on a reasoned schedule for a rate design window proceeding.

The Ruling asks parties to address the similarities and differences between their proposals and the conceptual framework for a successor tariff presented in a white paper prepared by the Commission's consultant E3, *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with AB 327* (E3 White Paper), released on January 28, 2021. SEIA and Vote Solar have reviewed the E3 White Paper carefully. We commend E3 for its emphasis on striking a balance between the goals of AB 327: aligning compensation for customer-sited renewable DG with the benefits that these systems provide to the electric system, while at the same time ensuring adequate compensation for DG customers to preserve the sustainable growth of these resources in California.

Vote Solar and SEIA agree with many of the conceptual elements for the successor tariff that E3 proposes. We discuss these elements below, and indicate how our proposal incorporates the concepts in the E3 White Paper.

- **Gradualism.** There is a need to re-align the compensation that DG customers receive, but this reform should take place gradually, to avoid severe impacts on the customer-sited renewable generation industry in the state. As E3 states "[p]reservation of a viable market is likely to require a "glide path…" Our proposal is based on a gradual stepdown in export compensation over a five-year period, with the goal of producing bill savings equal to avoided costs, on a life-cycle basis, at the end of the period.
- **Preserve the economics of renewable DG.** The changes adopted in the successor tariff should be calibrated to ensure that BTM renewable generation remains a viable economic proposition for customers to install. E3 proposes that the stepdown in the compensation to DG customers should be calculated to continue to provide a 7.5-year simple payback to solar customers. Similarly, our proposal examines customer economics through the Participant Test. We generally agree that a payback of 7.5 years is reasonable to allow continued growth of these resources.
- **Levers to adjust – rates and compensation for DG output.** Changes to the economics of customer-sited renewable DG should be managed through changes to both the rates under which NEM 3.0 customers take service from the grid as well as the compensation they receive for the power that they produce. E3 proposes a variety of possible designs for new rates applicable to customers under the successor tariff, and suggests the use of a "Market Transition Credit" (MTC) – a $ per kWh credit paid to the

DG customers for all output and designed to provide the DG customer with a reasonable payback over time. The SEIA / Vote Solar proposal also adjusts both of these levers. Under our proposal, NEM 3.0 residential customers would use an electrification rate whose TOU rate differentials move much closer to marginal costs than other residential TOU rates. At the same time, there will be a defined stepdown in the rate for exports, through a series of five capacity-based steps, with the steps designed to reach cost-effectiveness on a lifecycle basis after the fifth and final step.

- **Use of net billing.** We agree with E3's characterization of net billing as a "middle ground" approach to a successor tariff that would avoid the disruption of moving to an entirely new paradigm such as a "buy-all / sell-all" structure.[58] Our proposal also focuses on making significant changes to the compensation for power exported to the grid, with the reductions in the export rate calibrated to balance the lifecycle benefits and costs of these resources.
- **Support other policy goals** such as electrification. We agree with E3 that the rates applicable to DG customers also need to support the state's broader policy goals, such as encouraging beneficial electrification through the adoption of other types of DERs such as EVs and electric heat pumps. E3 argues that the various rate designs that it suggests ultimately could be used for other types of DERs.[59] Our proposal takes that step immediately, by proposing that the foundation of NEM 3.0 should be the immediate use of the electrification rates that the Commission has already adopted for the IOUs. Customers are buying EVs, combining solar with storage, and installing electric heat pumps today. A TOU rate platform applicable to all of these types of DERs is needed now, and the available electrification rates should be the basis for the NEM 3.0 program.

Although Vote Solar and SEIA agree with these conceptual elements that form the framework of the E3 proposal, we do not agree with some of the numbers and analysis that E3 uses to illustrate these concepts. For example, many of the examples that E3 uses are based on

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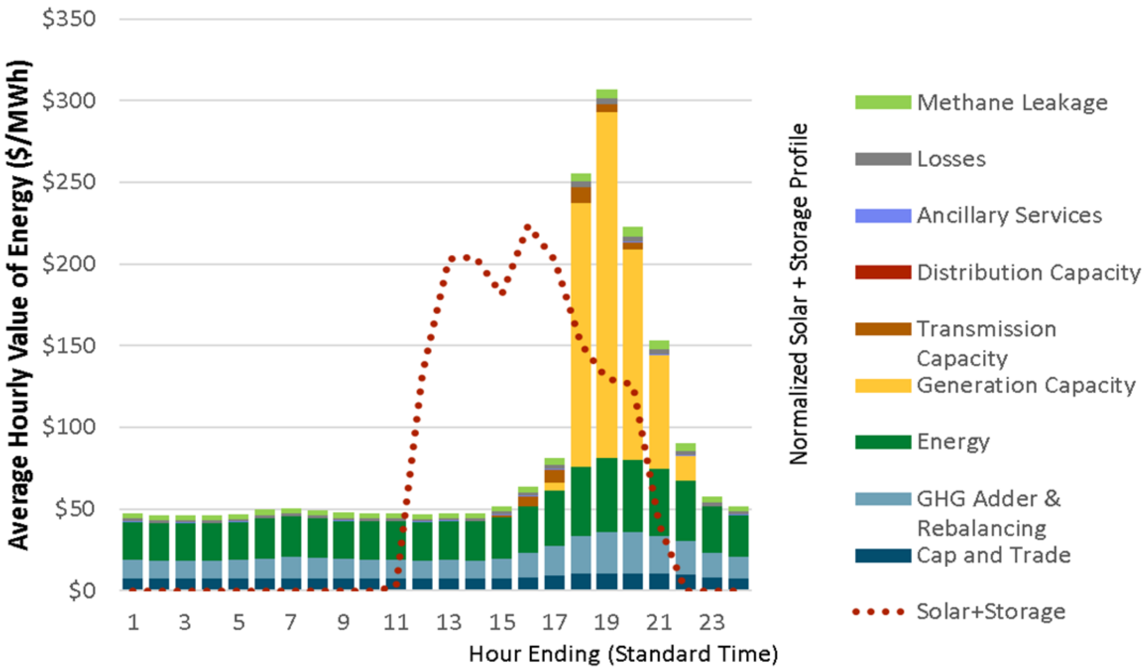
58 See E3 White Paper, at pp. 16-17.

59 *Ibid*., at p. 14: "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."

single year "snapshot" comparisons of solar bill savings to avoided costs from the 2020 ACC, or on comparisons that cover only a portion of a solar system's useful life. This includes the comparisons in E3's Figures 1, 2, and 5 and in Tables 3 and 6. For example, Tables 3 and 6 show a 2020 snapshot of avoided costs for BTM solar of 5.5 cents/kWh. The lifecycle, 25-year levelized avoided costs for a solar system installed in 2020 are 13.0 cents/kWh; the lifecycle avoided costs if this system has storage are much higher – 20.2 cents/kWh. Similarly, E3's Figure 4 shows that most solar generation does not occur in the hours of highest avoided costs. However, this picture looks significantly different with the addition of storage to shift the solar output into high-value evening hours, as shown in **Figure 7** below, which is a modified version of E3's Figure 3 to show a solar-plus-storage output profile. Solar and solar-plus-storage systems are long-lived assets whose benefits and costs must be assessed over their life cycle, not just a single year, if they are to be evaluated equitably against other demand- and supply-side resources. We appreciate E3's recognition at the workshop on its report that these single-year snapshot comparison were meant to be illustrative only, and that in this proceeding the Commission should develop a successor tariff using a long-term analysis that fully values the costs that these resource avoid over their useful lives. The Vote Solar / SEIA proposal has been developed using a lifecycle analysis that recognizes the long-term benefits of this new clean energy infrastructure.

Figure 7



We also differ from E3 on the need to calculate a specific MTC. The reductions in the export rate that we have proposed serve the same function as E3's declining MTC, without the complexity of calculating and accounting for this new rate component. Further, E3's MTC would be paid based on all output from the generation component of a BTM system,[60] which would require the unnecessary expense of additional metering to measure total system output, but would not accurately value this output if the customer then uses on-site storage to shift their output in time. The primary reason to calculate and track the MTC would be to enable the funding and recovery of these costs from a particular subset of ratepayers. For example, the E3 White Paper raises the possibility that future DER customers would pay for the MTC, presumably through future reductions in their compensation for exports to the grid. Vote Solar and SEIA strongly oppose this idea. First, such a scheme would reduce substantially the value of the MTC, by converting it, in effect, into a loan.[61] Many customers – particularly low- and moderate-income customers whose access to solar should be encouraged and supported – already borrow money to finance their systems, with the bill savings as the primary source to repay these

[60] *Ibid*., at p. 17: "In our application, the MTC is focused on BTM solar and is structured as a $/kWh credit applied to all generation."

[61] E3 acknowledges this problem, at p. 19, and notes correctly that it could "limit customer adoption." Lower-income customers who cannot afford such an enforced loan are th eons most likely to be foreclosed from adopting DERs.

loans. The willingness of lenders to make these loans would be undermined if their customers also must repay the MTC "loan" to the utility. This concept also will raise difficult issues if customers whose solar systems are supported by the MTC are able to add low-cost storage after their solar systems are paid off, and then are able to reduce their use of the grid or even to exit the grid entirely without re-paying the MTC. Some market segments – in particular medium and large commercial customers whose rates include significant demand charges – could have a negative MTC, if avoided costs exceed the bill savings necessary to support economic BTM systems. Would these negative MTC amounts be used to offset positive MTC from the residential market? Today, for all types of DERs – including energy efficiency, demand response, or DG – any difference between lost revenues/bill savings and avoided costs, in either direction, are borne by all customers over time. This recognizes that DERs are cost-effective for the system as a whole, as established by the TRC and Societal tests, even though they may have different impacts on participants versus non-participants. More generally, this Commission has never required customers who receive support through programs funded in utility rates – for example, low-income CARE customers or solar early adopters supported through the CSI – to repay the specific support that they receive. These programs are recognized as having broader societal benefits that justify funding from all ratepayers. We note E3's acknowledgement that the socialization of the limited amount of transition costs represented by the MTC is reasonable "if the gap between the bill savings required for a viable payback period and the system avoided cost value narrows fairly quickly."[62] That is the intent of the SEIA / Vote Solar proposal.

Finally, the rate design section of the E3 paper focuses heavily on rates with substantial fixed charges (of various kinds) of $40 per month or higher, and correspondingly lower volumetric rates. The white paper shows that such rates would save money for other types of DERs that promote electrification, but without considering the savings from reduced purchases of natural gas or gasoline.[63] However, such rates would require a significant MTC for solar to be viable. This strongly suggests a happy medium that the E3 paper fails to explore, which is the use of current electrification rates with more moderate fixed charges in the range of $10 to $15 per month. As our proposal has demonstrated, the use of these rates can provide a path forward that reduces the impacts of solar adoption on non-participants, pushes forward the deployment of

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62 *Ibid*., at p. 19.
63 *Ibid*., at pp. 25-26 and Table 7.

solar-plus-storage systems, and provides an immediate platform from which customers can adopt other types of DERs that promote beneficial electrification. This is the path that California should follow.

VII. CONCLUSION

The Solar Parties appreciate the opportunity to provide the Commission with this proposal for a NEM successor tariff which will continue and build upon the success of California's program for renewable distributed generation.

Respectfully submitted this March 15, 2021, at San Francisco, California.

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Land-use Constraints on Utility-scale Solar Deployment in California

The CPUC's resource planning process has recognized for many years that there are land-use constraints on renewable energy development in California. Studies of these constraints have focused on the utility-scale solar and wind resources that require significant amounts of land for development and that have been the principal renewable technologies developed for the state's Renewable Portfolio Standard (RPS) program. We have reviewed the constraints on utility-scale solar development calculated in the most recent of these studies and how these limits have been used (or, more importantly, ignored) in recent resource planning efforts, to assess how these constraints will impact California's future need for distributed solar resources that can be sited in the already-built environment.

The CPUC's current primary tool for its Integrated Resource Planning (IRP) process is the RESOLVE model, which includes a topology of regions in California where wind and solar resource development is likely. These regions are called "competitive renewable energy zones," or CREZ. The input assumptions for RESOLVE include land use constraints[64] on renewable deployment in these CREZ that are derived from prior work for the CPUC's RPS Calculator model, a predecessor to RESOLVE. The consultant Black & Veatch (B&V) developed and refined these land use constraints over multiple versions of the RPS calculator, building on B&V's extensive previous work on land use issues associated with renewable development for the Renewable Energy Transmission Initiative (RETI), which has been California's multi-agency planning process for identifying necessary and feasible transmission projects to support renewable deployment in the state.

The version of RESOLVE used in the first two-year IRP cycle (starting in 2017) included land use constraints from B&V's work on the RPS Calculator Version 6.3.[65] B&V developed a set of environmental screens to filter the technical potential for solar deployment in each CREZ, resulting in maximum limits on solar deployment available to be selected by RESOLVE. These environmental screens include:

- Base: includes RETI Category 1 exclusions only
- Environmental Baseline (EnvBase): includes RETI Category 1 and 2 exclusions
- NGO1: first screen developed by environmental NGOs[66]
- NGO1&2: second screen developed by environmental NGOs

[64] These constraints are found in the "Resources – Scenario Costs" tab of the RESOLVE model's Scenario Tool. See columns GL to HU of that tab.

[65] See B&V, *RPS Calculator V6.3 Data Updates* (September 7, 2016 presentation) at Slides 4-18, at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf.

[66] These NGOs were the Sierra Club, the Nature Conservancy, and Defenders of Wildlife.

- DRECP/SJV: includes RETI Categories 1 and 2 plus preferred development areas only in the Desert Renewable Energy Conservation Plan area and the San Joaquin Valley.
- Minimum: represents the minimum available potential across all screens

The potential solar development in each CREZ for each of these environmental screens, as used in RESOLVE in the 2017-2018 IRP, is summarized in the following **Table A-1**, from the documentation for the 2017 version of RESOLVE by its developer, Energy & Environmental Economics (E3).[67]

Table A-1: *Maximum Solar Deployment (MW) with RESOLVE Environmental Screens*

CREZ	RESOLVE Environmental Screen					
	Base	Env Base	NGO1	NGO1&2	DRECP And SJV	Minimum
Central Valley North Los Banos	3,988	3,021	3,901	2,477	1,264	1,264
Greater Carrizo	4,572	2,787	4,540	2,734	3,805	2,734
Greater Imperial	7,797	5,155	7,702	4,928	9,143	3,953
Mountain Pass El Dorado	288	15	288	10	62	10
Northern California	29,319	19,572	28,715	16,192	19,649	16,192
Riverside East Palm Springs	4,172	2,289	4,145	2,198	14,339	1,420
Solano	6,147	3,624	5,925	2,937	3,729	2,937
Southern California Desert	3,283	1,084	3,246	1,043	12,096	448
Tehachapi	4,535	3,493	4,464	3,446	1,073	1,073
Westlands	13,147	11,310	12,661	9,317	15,750	7,643
Utility-scale Solar Total	**77,248**	**52,350**	**75,587**	**45,282**	**80,910**	**37,674**

[67] See E3, *RESOLVE Documentation: CPUC 2017 IRP* (September 2017), at pp. 30-32, esp. Table 18, available at. https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentB.RESOLVE_Inputs_Assumptions_2017-09-15.pdf.

The Reference System Portfolio (RSP) developed in the 2017-2018 IRP extended only to 2030, and included a total of about 20,000 MW of solar deployment by 2030, which was well within all of the possible land use limits on solar deployment shown in Table A-1.[68]

The second 2019-2020 IRP cycle also has used RESOLVE. However, the 2019-2020 IRP includes analyses that significantly extend the 2017-2018 analysis in both time and scope. The 2019-2020 IRP includes scenarios out to 2045 and a "No New DER" case in which all forecasted deployment of distributed energy resources (DERs), including energy efficiency and distributed solar, are replaced with additional utility-scale renewable resources. Both the 2045 scenarios and the No New DER case include substantially more solar deployment than the land use limits on solar development included in the 2017-2018 IRP model. The 2019-2020 RSP, adopted in D. 20-03-028, included modeling to 2045 that showed 92,000 MW of utility-scale solar by 2045.[69] The No NEW DER case included 41,150 MW of utility-scale solar in 2030 and 131,400 MW in 2045.[70] Obviously, this is far more utility-scale solar by 2045 than the limits shown in Table A-1 above for the 2017-2018 IRP modeling, regardless of which environmental screen is selected. As early as 2030, the No New DER case would push up against the more stringent of the possible constraints. **Table A-2** summarizes this comparison.

Table A-2*:* *IRP Utility-scale Solar vs. Land-use Constraints*

Year	2019-2020 Reference System Portfolio (MW)	2019-2020 No New DER Case (MW)	2017-2018 Land Use Limits on Solar (MW)
2030	25,900	41,150	37,700 to 89,100
2045	92,000	131,400	

The reason why the 2019-2020 modeling of these cases did not reach RESOLVE's land-use constraints is that Energy Division and E3 arbitrarily raised those limits by a factor of four, compared to the limits shown in Table A-1. The justification for this change is contained in a short footnote to the documentation for the 2019-2020 RESOLVE modeling:

> *In 2017 IRP, candidate solar capacity as calculated from Black and Veatch geospatial analysis was discounted by 95% to reflect land use constraints and preference for geographic diversity. This value has been updated to 80% in 2019 IRP as geographic diversity is largely enforced by transmission limits. Solar potential reflected in the table above is therefore around 4 times the 2018-2019 potential assumptions.*[71]

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68 See D. 18-02-018, at Figure 3 and Table 1.

69 See the Reference System Portfolio, for the March 23, 2020 RESOLVE model package, posted at https://www.cpuc.ca.gov/General.aspx?id=6442464143. The cited amount is shown on the Dashboard tab of the RESOLVE Results Viewer, at row 66, with the "46MMT_20200207_2045_2GWPRM_NOOTCEXT_RSP_PD" scenario loaded in the model.

70 See the No New DER scenario results, for the March 23, 2020 RESOLVE model package, as referenced in Footnote 56. The cited amount is shown on the Dashboard tab of the RESOLVE Results Viewer, at row 66, with the "…NoNewDER" scenario loaded in the model.

71 See CPUC Energy Division and E3, *Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning* (October 2019) at p. 41, footnote 26, available at

The constraints shown in Table A-1 were presented in 2017 strictly as land use constraints, not as a supposed "preference for geographic diversity" (which is nowhere discussed in the 2017 RESOLVE documentation).[72] The footnote to the 2019 RESOLVE documentation appears to be an *ad hoc* justification for relaxing the land use constraints previously adopted in the 2017 IRP and the prior work with the RPS Calculator, so that land use constraints would not impact the 2019 IRP modeling of cases extending to 2045 and with no new DERs added.

The land use constraints identified in the 2017 IRP, when compared to the RESOLVE results from the 2019-2020 IRP, show that there will be significant land use constraints on utility-scale solar deployment in the period from 2030 to 2045. This risk will be heightened if the state does not continue its present pace of deployment of distributed solar resources. This conclusion is reinforced by recent developments since RESOLVE's land use constraints were last reviewed in 2015-2016. These include the proposed limits on large-scale solar development to preserve Joshua trees[73] and Governor Newsom's pledge to conserve 30% of the state's lands.[74] Finally, it is important to emphasize that this review does not consider the land-use implications of the new high-voltage transmission that would be needed to serve California's renewable energy needs exclusively with utility-scale resources that are remote from the state's load centers.

The clear conclusion of this review is that California will need to maintain sustainable and economic access to <u>both</u> its distributed <u>and</u> utility-scale solar resources, if the state is to achieve its long-term carbon reduction goals as set forth in SB 100. The No New DER case may be appropriate for modeling the long-run economic value of DERs, but the fact that this case could be run only by relaxing RESOLVE's land-use constraints by a factor of four shows that it does not value this important societal benefit from distributed solar resources that can be deployed to serve customers' loads on their premises, in the already-built environment.

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https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Prelim_Results_Proposed_Inputs_and_Assumptions_2019-2020_10-4-19.pdf.

[72] The footnote does not explain exactly what is meant by "geographic diversity" or explain its role in resource planning. California obtains its existing wind and solar resources from multiple geographically diverse regions that are widely distributed across the state, and this is expected to continue. A lack of geographic diversity has never been a stated concern for renewable resource planners in the state, and it is not an attribute that is quantified or valued explicitly in the resource planning process.

[73] The Center for Biological Diversity has petitioned the state to list the Western Joshua Tree as a threatened species under the California Endangered Species Act (CESA). See the August 6, 2020 letter to the California Fish and Game Commission from SEIA, the Large-scale Solar Association, the California Wind Energy Association, and the American Wind Energy Association California on the impacts of granting this petition on renewable development in California.

[74] See https://www.gov.ca.gov/2020/10/07/governor-newsom-launches-innovative-strategies-to-use-california-land-to-fight-climate-change-conserve-biodiversity-and-boost-climate-resilience/.

Reliability and Resiliency Benefits of DERs

Solar-plus-storage units can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad benefits as a way to maintain functions related to safety, human welfare, and economic activity during grid outages. They can be the foundation for more resilient neighborhoods and protect critical infrastructure. Obviously, this benefit has assumed increased importance in California given the heightened concerns with wildfires and the Public Safety Power Shutoff programs now in place for all of the IOUs.

Recently, the literature on mitigating power system interruptions has distinguished between **reliability** and **resiliency** benefits. In this discussion, "reliability" refers to the ability of an electric system to maintain service in the face of normal challenges to continuous operations, while "resiliency" emphasizes the ability to respond to and recover from low-frequency, high-consequence, "dark sky" events that may last longer in time and affect a larger area.[75] DERs that combine a renewable generation source (such as solar) with on-site storage can provide both reliability and resiliency benefits. The storage provides the assurance of immediate, <u>reliable</u> power if the grid goes down, while the on-site generation is available to re-fill the storage to maintain a level of <u>resilient</u> service for critical loads through an extended interruption.

We focus here on quantifying the resiliency benefits of solar-plus-storage systems. To maintain a basic level of electric service during an extended grid outage requires some form of on-site back-up generation. As a result, one approach that has been used – most prominently by the U.S. military – to value resiliency is to use the capital costs of this back-up generation, plus the added operating and environmental costs during an extended outage. This is a "revealed preference" method based on the costs of a "defensive behavior" to mitigate the impacts of an extended interruption.[76] For example, if there is an extended power outage after a natural

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[75] For example, a recent report to the National Association of Regulatory Utility Commissioners (NARUC) discusses the distinction as follows, drawing on a 2016 report from the Electric Power Research Institute (EPRI):

> A major distinction between resilience and reliability is the scale and duration of the power interruptions contemplated. Reliability focuses on preventing disruptions that are "more common, local, and smaller in scale and scope," whereas resilience "addresses high-impact events, the consequences of which can be geographically and temporally widespread."

See Converge Strategies for NARUC, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices* (April 2019), at p. 8 (hereafter "NARUC Study"), citing Electric Power Research Institute, *Electric Power System Resiliency: Challenges and Opportunities* (2016), at p. 45. The NARUC Study is available at https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[76] See NARUC Study, at p. 17.

disaster, the sale and use of portable gasoline-powered generators will proliferate among residential customers who are trying to maintain a basic level of electric service on their premises.

To calculate a value for residential resiliency, we have sampled the costs for portable inverter electric generators from 2.5 kW to 5.5 kW in size that are compliant with CARB emission requirements for California. We sampled inverter generators because they are quieter to operate (but not as quiet as a battery), and noise is a significant environmental impact of these units (especially when a whole community is using them). The average cost of these units is about $472 per kW, to which must be added sales tax, fuel storage costs, and the installation of a manual transfer switch to feed the critical circuits in the home. These units are expensive to run, require fuel that must be carefully stored in a separate structure, and even the models that meet the voluntary CARB standards produce significant emissions of criteria air pollutants and carbon dioxide. We priced these additional impacts assuming use of these generators for seven days of interruption in a 10-year period. The total cost for such a system to provide 3.5 kW of residential resiliency is $3,650, or $104 per kW-year over the 10 years, as summarized in **Table B-1**.

Table B-1: *Components of Residential Resiliency Value*

Component	Cost	Notes
Generator	$472 / kW	1.8 to 5.5 kW units
	$1,650	Assuming a 3.5 kW generator
CA Sales Tax	$140	At 8.5%
Transfer Switch	$600	Manual switch & installation
Fuel Storage	$1,050	Fuel containers, annual rotation, locked shed
Excess Energy Costs	$60	Electricity costs above $0.25/kWh
Air Impacts	$149	NOx, PM2.5, GHG Planning Price[77]
Total	$3,650	Total for the 3.5 kW unit
	$104 per kW-year	Assuming 7 days of interruption per decade

In our opinion, this is a conservative (low) value, as it does not consider other downsides from small portable fossil generators, including the 70 annual deaths in the U.S. from carbon

[77] We estimated the air emissions for portable gasoline generators assuming emissions of NO_x and $PM_{2.5}$ at the CARB voluntary compliance standard for these small engines, although many small generators on the market do not comply with these standards. To value the heath impacts of emissions of criteria pollutants (NOx and PM2.5), we used the values provided in the white paper by Tom Beach of Crossborder Energy and Alison Seel of the Sierra Club, *Non-Energy Benefits of Distributed Generation* (August 3, 2015), which is in the record for R. 14-10-003 as Attachment 2 to SEIA's comments filed March 23, 2017. For the GHG costs, we used the average 2018-2030 GHG Planning Price less $20 per ton for the cap & trade value of GHG emissions from gasoline, which were assumed to be included in the $4 per gallon cost of gasoline.

monoxide poisoning associated with the use of these units,[78] the limited fuel capacity that may result in significant risks from the transportation, handling, or storage of fuel,[79] and the added wildfire risks that operation of these units presents.[80]

The resiliency value for commercial customers appears to be similar, with one study of resiliency options for the U.S. military using an assumed cost of $80 to $85 per kW-year for the 20-year cost to protect a kW of load using individual diesel generation units for typical buildings on a military site.[81] The National Renewable Energy Laboratory (NREL) has a similar study of diesel generator backup costs that assumes a capital cost of about $70 per kW-year plus $35 per kW-year for ongoing maintenance.[82] These costs may be low for diesel gensets that meet strict California air emission regulations. We assume that the cost of diesel fuel will be roughly equal to the California retail electric rates ($0.20 per kWh) that the diesel generation replaces. In addition, we calculate air emission costs of $1 per kW-year assuming seven days of outage per decade, based on current CARB standards for stationary diesel units. The total resiliency value is thus $106 per kW-year ($70/kW-year for capital, $35/kW-year for maintenance, and $1/kW-year for air emissions).

These resiliency benefits are annual values, escalating with inflation, that apply to solar-plus-storage systems based on the kW discharge capacity of the battery system. These are clearly benefits that accrue not just to the customer who installs such a system, but to the electric system as a whole. Thus, they should be benefits in the Total Resource Cost and Societal Cost tests.

Moreover, the widespread adoption of such resilient systems has broader benefits for *all* ratepayers, as well. "Black sky" events that interrupt the grid for prolonged periods are exactly the times when neighbors must help and depend upon each other, and when communities will pool their resources to help those most affected by the event. These are the times when people will lend a helping hand to their neighbors and will share the resilient resources available to them. Thus, even customers who have not installed such a system will be better off if several of

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78 See U.S. Consumer Product Safety Commission, "Incidents, Deaths, and In-Depth Investigations Associated with Non-Fire Carbon Monoxide from Engine-Driven Generators and Other Engine-Driven Tools, 2005-2016," at p. 5, available at https://www.cpsc.gov/s3fs-public/Non-Fire-Carbon-Monoxide-from-Engine-Driven-Generators-2005-2016-June%202017.pdf?FL5ZFHu050hLH_NGRwJtpM2EE4JHeveV.

79 These generators typically have fuel tanks large enough for no more than two days of operation at five to eight hours per day.

80 See, for example, https://www.sfchronicle.com/california-wildfires/article/During-PG-E-outages-generators-caused-fires-14833601.php.

81 NARUC Study, at pp. 26-27, citing Marqusee, J., Schultz, C., and Robyn, D., *Power Begins at Home: Assured Energy for U.S. Military Bases* (2017), commissioned by The Pew Charitable Trusts.

82 S. Ericson and D. Olis, *A Comparison of Fuel Choice for Backup Generators* (NREL, March 2019), at pp. 20-21 and 25-27.

their neighbors, the local fire station, or the emergency shelter at the nearby school have assured backup supplies of electricity. To assume that resiliency is a strictly private benefit that accrues only to the customer that installs a backup system is to assume that people will not help their neighbors in a time of crisis. Thus, we include the resiliency benefit in the Ratepayer Impact Measure test.

Attachment C

The Nevada Experience: Abrupt Changes to NEM and Legacy Rules

The Commission should consider carefully the experience in Nevada from 2014-2016, where fundamental changes to the NEM structure had serious consequences to the solar market for both DG customers and solar businesses. As part of 2013 legislation (AB 428) to encourage rooftop solar, the Public Utilities Commission of Nevada (PUCN) commissioned E3, with support from a broad range of stakeholders including the solar industry, to prepare a study to "forecast the costs and benefits of renewable generation systems that qualify for the state's net metering program" from 2014-2016. The July 14 report and "Public Tool" model that E3 produced, using a long-term avoided cost analysis, found a $36 million net benefit to non-participating ratepayers over the lifetimes of these systems.[83]

In 2015 the solar industry and the utility NV Energy were at odds over whether or not to increase the state's NEM cap, as more customers adopted solar and solar businesses moved into the state. In the summer of 2015, the PUCN reviewed a study of net metering in Nevada commissioned by NV Energy that assessed NEM based on the short-term cost of service for residential and small commercial customers who install solar DG. The PUCN issued a decision on December 22, 2015 which accepted the results of that study, and, based on that evidence, found that there was now a significant cost shift from solar DG customers to non-participating ratepayers. The PUCN then ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems to an energy-only wholesale rate of 2.6 cents per kWh.[84]

The reduction in the export rate and the increased fixed charge significantly reduced the bill savings available to NEM customers in Nevada. DG was no longer economic for new systems, and the controversy became particularly heated because the PUCN applied the new rates to existing solar customers as well as to prospective ones. About 32,000 existing solar customers who expected modest savings from their solar investments under full retail NEM faced substantial added costs for electric service. These changes decimated the rooftop solar market in Nevada for new systems, resulting in more than 1,000 documented immediate layoffs at solar companies.[85] The changes sparked significant public outcry, a statewide ballot initiative, and lawsuits involving outraged solar customers, solar companies, and the state, as investments in renewable DG had been severely and unexpectedly altered.

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[83] For the July 2014 E3 report, see https://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.

[84] See the Order adopted by PUCN on December 22, 2015 in Dockets Nos. 15-07041 and 15-07042.

[85] The immediate impacts of the PUCN decision to make a substantial change to the NEM structure in Nevada, and to apply that policy change to existing NEM customers, including the layoffs at solar companies, is documented in the *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of The Alliance for Solar Choice*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

A year later, in 2016, after significant public and political debate, the PUCN reversed course. The PUCN's first step was to adopt an explicit grandfathering policy, allowing existing solar customers at the time of the change in NEM policy to net meter at full retail rates for a 20-year period.[86] The PUCN subsequently adopted a limited reopening of full retail net metering in Nevada.[87] In the order reinstating net metering, the new chair of the PUCN wrote:

> *The landscape on these issues continues to grow. Abraham Lincoln once said that 'Bad promises are better broken than kept.' The PUCN's prior decisions on NEM, in several respects, may be best viewed as a promise better left unkept. The PUCN is free to apply a new approach.*[88]

Pursuant to 2017 legislation (AB 405), the compensation for the exports from new solar DG customers in Nevada has been set at a small (5%) discount to the retail rate, with the discount increasing in steps for every 80 MW of DG that is installed. The compensation structure for exports is guaranteed for 20 years for new DG customers. The legislation also includes consumer protection provisions and a Solar Bill of Rights specifying that every Nevada customer has the right to generate and store solar energy and providing that each solar customer will be in the same class and have the same rate options as non-solar customers.[89]

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86 See https://www.greentechmedia.com/articles/read/nevada-regulators-restore-net-metering-for-existing-solar-customers#gs.aExnCD4.

87 See https://www.greentechmedia.com/articles/read/nevada-regulators-retore-retail-rate-net-metering-in-sierra-pacific-territo.

88 See PUCN Order in Dockets Nos. 16-06006 *et al*. issued December 20, 2016, at p. 39. Available at http://pucweb1.state.nv.us/PDF/AXImages/Agendas/25-16/6801.pdf.

89 The PUCN implemented the provisions of AB 405 on September 1, 2017 in its *Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405* in PUCN Docket No. 17-07026.