BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

OPENING BRIEF OF THE CALIFORNIA WIND ENERGY ASSOCIATION

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On behalf of the California Wind Energy Association

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Pursuant to Rule 13.11 of the Rules of Practice and Procedure, the California Wind Energy Association ("CalWEA") respectfully submits this opening brief on the issues identified in the November 19, 2020, Scoping Memo and Ruling of Assigned Commissioner Guzman Acevez and Administrative Law Judge Hymes, with particular focus on the Guiding Principles adopted in Decision 21-02-007. In this limited opening brief, CalWEA explains why it is endorsing the Joint Recommendations of the Independent Parties and why the Commission should reject any arguments that sustaining the historically high rate of rooftop solar growth is necessary to achieve the state's SB 100 goals or to address concerns related to the need for utility-scale resources and related land-use that would otherwise be required. In fact, continuing that high rate of growth would lead to higher costs and the need for more utility-scale resources.

I. To Meet the Commission's Guiding Principles, the Commission's Successor Tariff Should Follow the Joint Recommendations of the Independent Parties

CalWEA endorses the Joint Recommendations of the Independent Parties, attached hereto as Attachment 1, apart from Section 4, because they provide the Commission with a sound, broadly supported and comprehensive framework for ensuring that the Commission's adopted successor to the current net energy metering ("NEM") tariff will reasonably satisfy the Commission's adopted Guiding Principles.[1]

[1] CalWEA did not endorse Section 4 of the Joint Recommendations because it is too narrow to accommodate TURN's proposal, which also presents a meritorious approach to supporting rooftop solar

Neither the law nor the Guiding Principles guarantee to the solar industry a continuation of the high level of growth that it has enjoyed under the NEM 1.0 and 2.0 tariffs. Guiding Principle (b) – "a successor to the net energy metering tariff should ensure equity among customers" – demands that the current massive cost-shift from NEM customers to non-NEM customers be substantially reduced, if not eliminated.[2] The Commission's Public Advocates Office ("Cal Advocates") estimates that, without reforms to the NEM 1.0, 2.0, and successor tariffs, the total annual cost burdens on non-NEM customers will grow to a staggering $6.9 billion annually by 2030.[3] As calculated by TURN based on the Commission's Net Energy Metering 2.0 Lookback Study, this cost-shift equates, conservatively, to over $31,402 for each NEM 2.0 customer on a 20-year present-value basis.[4]

As pointed out by TURN and other parties, the Commission's Energy Division staff has recognized that existing NEM policy "contributes to rate increases" because "IOUs pay more in NEM bill credits than they would pay elsewhere for the same amount of electricity and other electric grid benefits" and that the NEM cost shift to lower-income non-participants is one of "three critical and overlapping regulatory fronts that must be actively managed" to address the widening gap between participants and non-participants in behind-the-meter and distributed energy resource programs.[5] Cal Advocates explains that the Commission must minimize increases in electric rates to achieve the State's ambitious greenhouse-gas-reduction ("GHG") goals, which depends upon customer adoption of electric vehicles and building electrification.[6]

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adoption among low-income customers. TURN proposes to provide an up-front Market Transition Credit incentive to low-income customers, rather than waiving the Grid Benefits Charge. As explained by TURN, its proposal would ensure that incentives are transparent, reduce customers' upfront investment, achieve a reasonable payback period, and pose no continuing concern about future cost-shifting impacts. (See TRN-O1 at pp.51-52.)

[2] As explained by Cal Advocates, the cost burden occurs when non-NEM customers are required to pay NEM customers for their generation that is not supported by any value provided to the system. PAO-01 at 2-39, lines 10-13.

[3] PAO-01 at Table 2-2.

[4] TRN-01 at p. 9, lines 19-21. TURN notes that this figure is based on the 2020 Avoided Cost Calculator (ACC) and that using 2021 ACC values would yield a significantly larger value.

[5] TRN-01 at p. 39, citing CPUC Energy Division's May 2021 *Utility costs and Affordability of the Grid of the Future* report and related presentation.

[6] PAO-O1 at p. 2-23.

NRDC cites clear evidence that solar systems have disproportionately benefitted wealthier households.[7]

CalWEA's own testimony[8] further demonstrates that the current NEM tariff is inconsistent with the Commission's obligation to plan for a resource portfolio that achieves the state's SB 100 zero-carbon electricity goals while minimizing impacts on ratepayers' bills.[9] That objective is encompassed in the Commission's Guiding Principle (e) -- "A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including but not limited to, Senate Bill 100 (2018, DeLeon), the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18." As numerous parties have pointed out, the Commission's Integrated Resource Planning ("IRP") process currently "hard-wires" high levels of customer-side solar into the plan, rather than subjecting the resource to the same cost-effectiveness analysis process applied to all other resources.[10] CalWEA's witness, Dr. Dariush Shirmohammadi, used the Commission's RESOLVE model, just as it was used by the Commission, the Energy Commission and the Air Resources Board (the "Joint Agencies") to plan for the achievement of the state's SB 100 goals, to shed light on the cost-effectiveness of the 31.4 gigawatts ("GW") of customer-side solar that was hard-wired into the "core scenario" of the Joint Agencies' SB 100 Report. No party contested Dr. Shirmohammadi's finding that reducing the level of customer-side solar additions by half would, very conservatively, bring present-value savings of nearly $1.26 billion per year, or its conclusion that "[h]igher levels of rooftop solar substantially raise the overall cost of achieving California's GHG goals compared to relying on utility-scale renewables," based on the Joint Agencies' own SB 100 model.[11]

To meaningfully address all the above troubling problems caused by the current NEM tariff, each element of the Commission's successor tariff should fall squarely within the detailed

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[7] NRD-01 at p. 6.

[8] CWA-01.

[9] See TRN-01 at pp. 40-41 for a discussion of SB 100 and AB 327 regarding the state's zero-carbon electricity and Integrated Resource Planning policies, respectively.

[10] See CWA-01 at p. 6, lines 1-4; TRN-01 at p. 40, lines 22-24, and p. 41, lines 1-3; and IOU-01 at p. 91, lines 5-7.

[11] CWA-01 at p. 7, lines 1-15, and p. 8, lines 10-11.

framework provided by Joint Recommendations of the Independent Parties.[12] Further, because these problems directly compromise the Commission's ability to meet its obligation to achieve the state's GHG targets while minimizing impacts on ratepayers' bills,[13] the Commission should select, among the ranges of solutions provided in the Joint Recommendations, those solutions that reduce the cost-shift most substantially. This is necessary to meet the Commission's Guiding Principle (e), as stated above.

II. The Commission Should Reject Any Argument that a High Rate of Rooftop Solar Growth Is Necessary to Achieve the State's SB 100 Goals

The testimony of CalWEA witness, Dr. Shirmohammadi, provides clear evidence, based on the Joint Agencies' own model, that substantially reducing rooftop solar from the levels assumed in the Joint Agencies' SB 100 core scenario would substantially reduce the cost of achieving SB 100 goals, as discussed above. Further, CalWEA's testimony undercuts any claim that high levels of rooftop solar are needed to address concerns related to the need for utility-scale resources and related transmission and land-use that would otherwise be required. CalWEA's testimony shows the opposite: that <u>higher</u> levels of rooftop solar require <u>significantly more</u> utility-scale resources overall, based on the Joint Agencies' model.

Specifically, CalWEA found that the total need for utility-scale renewable energy resources would go up by less than 1 percent (less than 500 MW) if the level of customer-side solar were cut in half.[14] CalWEA also found that the need for long duration and battery storage capacity – a substantial portion of which is likely to be utility-scale, requiring substantial land[15] – is <u>reduced</u> by about 7.4 GW.[16] Dr. Dariush Shirmohammadi, explained these results by observing that, without so much storage on the system driven by customer-side solar, wind and geothermal resources – which produce energy outside of solar-production periods and generally

[12] Expanded to include TURN's approach to promoting solar adoption in low-income communities. See Note 1 *supra*.

[13] See TRN-01 at p. 40, lines 3-24, and p. 41, lines 1-3, for a discussion of SB 100 and AB 327 regarding the state's zero-carbon electricity and IRP policies, respectively.

[14] CWA-01 at p. 8, lines 22-24.

[15] For example, a proposed 600-MW battery storage facility at Morro Bay would be built on a 22-acre site. See *Paso Robles Daily News,* "World's largest utility-scale battery storage facility proposed for Morro Bay" (February 11, 2021). (Available at: https://pasoroblesdailynews.com/worlds-largest-utility-scale-battery-storage-facility-proposed-for-morro-bay/121389/).

[16] CWA-01 at Attachment 2, p. 2 (see lines for "Battery Storage" and "Pumped Storage").

have higher capacity factors than utility-scale solar – become more cost-effective.[17] (Less capacity is needed when capacity factors are higher.[18]) While more existing gas-fired capacity is retained to provide capacity, as shown by Dr. Shirmohammadi's modeling, that capacity is present to meet Resource Adequacy capacity needs but is operated very rarely, thus greenhouse gas emissions can be kept at the same level as the SB-100 core scenario.[19]

All told, including the reduced need for rooftop solar panels, the overall resource need declines by over 22.5 GW when rooftop solar growth is cut in half.[20] This is a 16 percent reduction in the additional renewable and storage resources needed to achieve the state's SB 100 goals. This eliminated capacity would translate to associated savings in metals, minerals, cement and other materials required for manufacturing and construction, as well as the avoided associated environmental impacts. Further, it is reasonable to expect that the 16 percent, 22.5-GW reduction in overall capacity – both utility-scale and customer-side – would also reduce the need for transmission and distribution resources, as well as land requirements. This is particularly true if, as shown in CalWEA's modeling results, geothermal energy, with its concentrated energy footprint, partially replaces more land-intensive utility-scale solar.[21]

III. CONCLUSION

CalWEA respectfully urges the Commission to adopt a successor tariff consistent with the Joint Recommendations that are made by a broad and diverse group of parties to restore equity across customers and to meet the requirements of state law. In so doing, the Commission should reject any arguments that continuing the historically high rooftop solar growth rates are needed to meet the state's SB 100 goals. CalWEA has provided evidence that the opposite is

[17] CWA-01 at p. 9, lines 8-12. Also see transcript for August 5, 2021, at p. 1503, lines 5-18.

[18] The capacity factors of geothermal, wind and utility-scale solar are approximately 75 percent, 35-45 percent, and 25 percent, respectively.

[19] CWA-01 at p. 9, lines 6-7 and 13-15. Also see CWA-01 at Attachment 2, p. 1 (see line for "Greenhouse Gas Emissions including BTM CHP").

[20] This figure is derived by adding 7.4 GW avoided storage to 15.7 GW avoided rooftop solar and subtracting the need for 0.5 GW in additional utility-scale renewable resources.

[21] CWA-01 at Attachment 2, p. 2. In CalWEA's alternative case with 50 percent less customer-side solar, geothermal resources increase by 884 MW and utility-scale solar decline by 2,426 MW. (The land-use requirements, in terms of square meters required per megawatt-hour, of utility-scale solar is significantly higher than for geothermal resources.)

true: high levels of customer-side solar would not only be far more costly but would increase the need for utility-scale resources.

Respectfully submitted,

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On behalf of the California Wind Energy Association

August 31, 2021

CALWEA ATTACHMENT:

JOINT RECOMMENDATIONS OF THE INDEPENDENT PARTIES

JOINT RECOMMENDATIONS OF THE INDEPENDENT PARTIES FOR A SUCCESSOR TARIFF TO THE CURRENT NET ENERGY METERING TARIFFS

The below groups, representing a diverse array of independent voices, provide the following set of Joint Recommendations to resolve the issues in Rulemaking (R.) 20-08-020. The groups recommend the California Public Utilities Commission (Commission) adopt these Joint Recommendations to effectively reform the current Net Energy Metering (NEM) tariffs. The Joint Recommendations span essential policies, export compensation, a Grid Benefit Charge, equity provisions, transition of legacy NEM 1.0 and 2.0 customers, and an interim tariff designed to make immediate progress on reducing the NEM cost burden until the successor tariff can be implemented in full.

The below groups recommend the Commission adopt the following sections of the Joint Recommendation.

Organization	**Support for Specific Sections of Joint Recommendations**
Public Advocates Office (Cal Advocates)	Sections 1-6
Natural Resources Defense Council (NRDC)	Sections 1-6
Coalition of California Utility Employees (CUE)	Sections 1-3, Sections 5-6
California Wind Energy Association (CalWEA)	Sections 1-3, Sections 5-6
The Utility Reform Network (TURN)	Sections 1-3, Sections 5-6
The Independent Energy Producers Association (IEPA)	Section 1-4, Section 5 Part 1 and Part 2a, Section 6

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SECTION 1 ESSENTIAL POLICIES FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on the NEM successor tariff should include the following fundamental policies:

- Fairly compensate successor tariff customers for the benefits of clean energy without unduly raising electric bills for non-participating customers by valuing successor tariff customers' exported energy using the most current Commission-approved Avoided Cost Calculator. The successor tariff should utilize net billing, which means one bill that separates compensation for exports, using a value that differs from the retail rate, and charges for consumption.
- Require successor tariff customers to pay their fair share for grid use by implementing a Grid Benefits Charge (GBC) to recover costs for transmission, distribution, non-bypassable charges, and any other shared system costs.
- Support lower income customers by protecting them from undue cost burden as a result of the existing or successor tariffs. Provide lower income customers with assistance to overcome structural barriers to adopting distributed energy resources.
    - Any incentives should be prioritized for lower income customers and should be provided upfront to reduce the initial system cost.
    - Transparently identify any subsidies to successor tariff customers and collect them, to the maximum extent possible, from sources other than utility rates.
- Transition existing NEM 1.0 and 2.0 non-California Alternate Rates for Energy (CARE) and non-Family Electric Rate Assistance (FERA) customers in a way that quickly decreases and eventually eliminates the NEM cost burden while ensuring a payback of the NEM customer's system cost over a reasonable period of time.

When developing different components of the successor tariff, the Commission should ensure the components interact in a manner that satisfies the essential policies outlined here.

SECTION 2 EXPORT COMPENSATION FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision on export compensation for the NEM successor tariff should include the following:

- Instantaneous netting or, if that is not possible, hourly netting to determine the (1) monthly quantity of electricity exported from the customer's premise to the grid and (2) the time periods at which these exports are made.
- Exported electricity should be compensated based on avoided costs, as calculated by the Commission's Avoided Cost Calculator (ACC).
- Avoided cost-based export values should be updated annually on January 1
- To avoid potentially large swings in export compensation levels due to different ACC versions, export values should be based on the two most recent Commission-adopted ACC versions.
- Export compensation rates should be differentiated either hourly or, at a minimum, by Time-of-Use (TOU) period to provide appropriate compensation for exported electricity and thereby also incentivize paired storage systems operation to support grid needs (e.g., charge during off-peak and discharge during on-peak periods).
- Export compensation should be structured to provide customers with the option to obtain predictable values for a defined period of time. There are two ways to provide this certainty:

  (1) Develop export compensation based purely on the ACC. Customers get locked-in to a predictable avoided cost-based export compensation for a period of up to 10 years (based on the recommended methodology to provide a stable export compensation signal described below).

  (2) Lock-in all avoided cost values except avoided energy costs.[1] The avoided energy costs will be taken from the day-ahead or real time-market.

  - Explanation – Although the use of ACC energy cost forecasts will provide a more stable signal, tying a portion of export compensation to the day-ahead or real-time market would better align with observed avoided energy supply costs, and it would provide a more accurate signal and allow customers to receive higher payments during periods of supply scarcity (when electric prices are very high). Each method has its advantages. The joint recommendations are agnostic on which of these are chosen, i.e., tying the avoided energy cost component of the export compensation purely to the values in the ACC or to the day-ahead or real time market.
- To provide more certainty to customers considering installation of a behind the meter (BTM) generation system, the initial export compensation may be locked in for up to 10

[1] The avoided energy cost is a specific component of the ACC's avoided costs that is linked to the costs of procuring energy (kWh) from CAISO wholesale energy markets.

years.[2] After the lock-in period, export compensation rates should be updated annually on January 1 using the method described above.

- o Because successor tariff customers may lock-in export values for several years, the export value should be based on the estimated ACC values for all years associated with the lock-in period.[3] If fixed levelized values are used rather than the forecast values for each future year in the ACC, the levelized values should not be based on forecasts beyond the next four consecutive years.[4]
- o The lock-in export vintage should be determined by the calendar year that a customer submits a complete Interconnection Request. For example, a customer who submits a complete Interconnection Request in 2022 should receive the export rate adopted on January 1, 2022 (based on the 2020 and 2021 ACCs), even if the BTM system doesn't receive permission to operate until 2023.
  - i. The lock-in period for each customer should start on January 1 of the calendar year in which they receive permission to operate. The lock-in period for customers who receive permission to operate on or after July 1 will begin January 1 of the following year. For example, assuming a five-year export compensation lock-in, a customer who interconnects on July 1, 2022, would receive the locked-in exports rates until December 31, 2027. This provision will ensure that all customers will have the opportunity of benefitting from the adopted lock-in period plus or minus six months.
- o The TOU or hourly export values, with the possible exception of the avoided wholesale energy costs, should be fixed for the duration of the lock-in period.[5]
- o When determining a lock-in period, the Commission should ensure the different components of export compensation interact with each other and other aspects of the successor tariff in a manner that satisfies the principles outlined in Section 1.

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[2] Parties provide their recommendations for a specific lock-in duration (up to 10 years) in briefs.

[3] For example, if a customer joins the successor tariff in 2023, their export compensation rate in 2026 would be the 2022 version ACC forecast for 2026.

[4] For example, a peak TOU export compensation rate for a BTM generation system that completes interconnection in 2021 would be averaged using TOU peak avoided costs over 2022-2025 from the 2019 and 2020 versions of the ACC.

[5] For example, with a five-year lock-in period the TOU export compensation rates for a BTM generation system that submits an Interconnection Request in 2021 and receives permission to operate before July 1, 2021, would be based on the levelized avoided costs over 2021-2025 from the 2019 and 2020 versions of the ACC.

SECTION 3 GRID BENEFITS CHARGE FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should include a Grid Benefits Charge (GBC) with the following aspects:

- Successor tariff customers should pay a GBC that includes transmission and distribution costs of service, as well as the non-bypassable charges (NBCs) described below, to fairly recover shared system costs that are currently unpaid by NEM customers.
- For GBCs that are denominated on a $/kW of installed BTM capacity basis, the final GBC amounts should fall within the following range:
    - Lower end of $6.37 – $8.32/kW.[6] Distribution and transmission components from Cal Advocates and certain NBC components from TURN; and
    - Upper end of $10.24 – $14.13/kW.[7,8] GBCs proposed by the joint IOUs that are estimated by valuing all BTM production at avoided costs.
- The GBC should be based on successor tariff customers' BTM system size, energy production or portion of production consumed onsite.
    - Since certain NBCs are required to be collected based on usage, all NBCs should be assessed on a volumetric basis. The NBC charges should apply to customers' total on-site electricity consumption, which is the sum of measured imports, using either instantaneous or billing interval netting, and the electricity simultaneously produced and consumed onsite, which is equal to total generation minus exports.
    - Successor tariff customers should be given two choices to measure BTM system generation: installation of a separate, utility-grade meter to track on-site generation during each billing cycle, or the use of an engineering estimate of the total monthly on-site generation of the customer's BTM system.
- The GBC should include the following NBCs, at a minimum:
    - Public Purpose Programs (PPP);
    - Wildfire Fund Charge;
    - Nuclear Decommissioning;
    - Competition Transition Charge (CTC);
    - Reliability Services (RS);
    - New System Generation Costs (NSGC);
    - Investor-Owned Utility (IOU) securitization costs relating to wildfires or other undercollections;
    - Energy Cost Recovery Account (for PG&E); and
    - PUC Reimbursement Surcharge.
- The GBC may include the additional NBC:

[6] The lower end should be $6.37/kW for San Diego Gas & Electric Company (SDG&E), $8.23/kW for Southern California Edison Company (SCE), and $8.32/kW for Pacific Gas and Electric Company (PG&E).
[7] The upper end should be $14.06/kW for SDG&E, $10.24/kW for SCE, and $14.13/kW for PG&E. From Joint IOUs Opening Testimony.
[8] These values do not include the Energy Resources Recovery Account costs or the PG&E wildfire securitization costs, which should also be added.

- Power Charge Indifference Adjustment (PCIA).[9]

- The GBC for non-residential customers should include at least the NBCs listed above. The Commission should require the utilities to propose reforms in the next rate design phases of utility General Rate Cases (GRC2s) or Rate Design Window (RDW) proceedings to look specifically at GBCs for non-residential customers.
- Because all electricity generated by Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEM-A) systems is treated as exports to the grid, the GBC should not be levied on benefitting accounts in VNEM and NEM-A arrangements, except for any NEM-A residential account with generation behind the meter.
- Please refer to Section 4 for additional exemptions to the GBC.

[9] The PCIA includes the above-market energy and capacity costs of the utilities' generation portfolios, as well as costs of utility-owned-generation assets and of managing the utilities' generation portfolios, that were incurred on behalf of all customers including successor tariff participants. Adoption of distributed generation does not reduce any of these legacy procurement costs. It would be consistent with the principles of cost causation and equitable allocation of shared generation system costs to include the PCIA in the GBC.

SECTION 4 EQUITY PROVISIONS FOR THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should include the following provisions to ensure equity:

- Exempt California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) successor tariff customers from the GBC.
- Apply a monthly Equity Charge of $3.41-3.81/kW[10] based on distributed generation capacity installed to all existing non-CARE/FERA residential NEM 1.0 and 2.0 customers.
    - o New non-CARE/FERA residential successor tariff customers should not pay the Equity Charge until a period of ten years from distributed energy resource (DER) generation system interconnection. CARE/FERA successor tariff customers should not pay this charge.
    - o The Commission should implement an inclusive process, with the input of representatives of disadvantaged communities, environmental justice groups, and consumer advocates, to decide how these funds should be spent. Below are some examples of how Equity Charge funds could be used promote equity in the Commission's DER policies.
        1. An up-front subsidy to CARE/FERA households to offset their costs of installation and address barriers to DER access, particularly in disadvantaged communities,
        2. Ensuring equity in payback periods between CARE/FERA and non-CARE/FERA successor tariff customers.[11] The Equity Charge can vary by IOU based on the amounts needed to ensure equity in payback periods, and
        3. Other DER programs that align with the Commission's Environmental Social Justice Action Plan.

[10] The Equity Charge should be $3.41/kW for SCE, $3.44/kW for SDG&E, and $3.81/kW for PG&E. From Cal Advocates' Opening Testimony.
[11] Currently, CARE/FERA NEM customers receive less value than non-CARE/FERA NEM customers for the energy they produce, because net-metered credits are valued at their discounted retail electricity rate.

SECTION 5 TRANSITION EXISTING CUSTOMERS TO THE NEM SUCCESSOR TARIFF

The Commission's final decision for the NEM successor tariff should adopt the following policies to transition existing NEM customers to the successor tariff to reduce the cost burden on non-participating customers:

If at any point an existing NEM 2.0 customer voluntarily switches to the successor tariff[12] on or after January 1, 2023, and until December 31, 2027, they should be given a rebate for a paired storage system.[13,14]

- o The incentive level should start at a $0.20/Wh storage[15] rebate on January 1, 2023, then be stepped down 10% annually until December 31, 2027.

The Commission should also adopt a process to transition existing NEM customers who do not voluntarily switch:

- Part 1:
    - a) Switch existing non-CARE/FERA NEM 1.0 and 2.0 customers to a new underlying TOU rate five years from the date of interconnection of their BTM generation systems or as soon as practicable for the IOU thereafter.
        - i. This new underlying TOU rate must be non-tiered and have at least a 2:1 differential between summer weekday peak and weekday off-peak periods.[16] Eligible rates include:
            1. PG&E: EV2, E-ELEC (if adopted in PG&E's General Rate Case Phase 2 Proceeding[17]);
            2. SCE: TOU-D-PRIME; and

[12] If the Commission adopts an interim tariff, the customer should be transitioned to the successor tariff's end-state.

[13] NEM 1.0 customers should be excluded from this incentive program as they have received more years of payback for their BTM system. An existing NEM 2.0 customer should not be eligible for any incentive if they have already been mandatorily switched over to the successor tariff.

[14] Incented paired storage systems should follow rules already supplied by the Self-Generation Incentive Program to ensure the system maximizes grid benefits.

[15] The current SGIP Small Residential Storage incentive level is $0.20/Wh. See: https://www.selfgenca.com/home/program_metrics/ (accessed August 20, 2021). In 2020, the average incentive for residential general market customers to purchase and install storage through SGIP was $3,172.80. See "Real-Time Public Report," accessed March 5, 2021: https://www.selfgenca.com/home/resources/.

[16] Community Choice Aggregation (CCA) customers must switch to one of the eligible rates described in Part 1.a.i.

[17] See Application 19-11-019.

3. SDG&E must enact a non-tiered TOU rate that accomplishes the required 2:1 rate differential.[18] Until an applicable rate is adopted, customers should transition to DR-SES or EV-TOU/EV-TOU2.

ii. The IOUs should be required to perform a marketing and outreach campaign at least 3 months in advance of any rate switching. Customer marketing and outreach shall include information on technologies and available incentives that can improve system value such as heat pump water and space heaters, electric vehicles, and batteries. In addition to potential operational cost savings from electrification and load shifting technologies, materials shall also explain the climate benefits of electrification and how utilizing energy during periods of mid-day solar generation and limiting evening usage reduces climate and air pollution.

b) Rate switching shall begin no later than January 1, 2023, at which point all existing non-CARE/FERA NEM customers that interconnected in 2017 or earlier shall be moved to the new eligible TOU rate. Existing NEM customers that interconnected after 2017 shall transition to an eligible rate five years from the date of interconnection or as soon as practicable for the IOU thereafter.

- Part 2:
  a) Concurrent with Part 1, five years from the date of system interconnection or as soon as practicable for the IOU thereafter, apply the GBC to all non-CARE/FERA NEM 1.0 and 2.0 customers.
  b) Eight years from the date of system interconnection or as soon as practicable thereafter,[19] switch all non-CARE/FERA NEM 1.0 and 2.0 customers to the successor tariff.

The table below provides the Public Advocates Office's projected reductions in NEM cost burden of this two-part approach for the PG&E, SCE, and SDG&E territories. Part 1 was based on the simplifying modeling assumption that all NEM customers switch to TOU rates with 2:1 price differentials *in 2026*, whereas in reality many customers will be switched before then. The Part 1 estimate (9.0%) is a lower bound estimate of the cost burden reduction, and the actual reduction to the cost burden will be larger depending on how many customers switch to the new TOU rates.

[18] In Decision (D.) 20-03-003, the Commission directed SDG&E to propose in its next residential rate design application an opt-in, un-tiered residential TOU rate with a fixed charge that would be available to residential customers charging an electric vehicle, utilizing energy storage, or utilizing electric heat pumps for water heating or climate control. In D. 21-07-010 , the Commission specifically directed SDG&E to submit its proposal no later than September 1, 2021. This rate could potentially meet the requirements specified in the document.

[19] All NEM 1.0 and 2.0 customers will have already reached their payback period by this point.

Commission Policy Adopted	Cost Burden Savings (in net present value)	Cost Burden Reduction	Cumulative Cost Burden Reduction
No Reform for NEM 1.0 or NEM 2.0 customers.	$0 (out of a total $41.1 billion)[20]	0%	0%
<u>Part 1</u>: switching existing NEM customers to a new underlying rate five years from the date of system interconnection.	$3.71 billion[21]	9.0%	9.0%
<u>Part 2a:</u> applying a GBC to all existing NEM customers from the date of five years of system interconnection.[22]	$6.21 billion	15.1%	24.1%
<u>Part 2b:</u> switching all existing customers to the successor tariff from the date of eight years of system interconnection.	$9.51 billion	23.1%	47.3%
<u>Offering an incentive</u> for NEM 2.0 customers to switch to the successor tariff.	$11.97 billion[23]	29.1%	76.4%

[20] The total net present value of the cost shift over all existing customers' 20-year legacy period is $41.1 billion.
[21] This is a conservative estimate of savings as it assumes that all customers transfer to a new underlying rate in the last year of Part 1.
[22] All Part 2 modeling includes CARE and non-CARE NEM customers.
[23] This cost reduction estimate assumes that 100% of NEM 2.0 customers accept the storage rebate in first year that the successor tariff is implemented (2022). Because the share of NEM 2.0 customers accepting the incentive and the timing of the uptake are uncertain, actual reductions in the cost burden will likely be lower.

SECTION 6 INTERIM TRANSITION TO THE NEM SUCCESSOR TARIFF

Because implementing the details of the successor end-state tariff may take time, the Commission should adopt an interim successor tariff for new residential NEM customers. This interim tariff should be required for new residential NEM customers only until the end-state successor tariff rate is implemented. Within 30 days of the Commissions' final decision on a successor tariff, the IOUs should file Advice Letters to implement the interim tariff. The interim tariff should be required for new residential NEM customers within 90 days of the final decision. Key features of the interim tariff should include the following:

- Residential customers should be required to take service on an electrification rate.
- Export compensation is set at a defined percentage reduction to the Non-CARE "net" electrification retail rate at the time the interim successor tariff is enacted in 2022. The "net" electrification retail rate is the residential electrification retail rate net of the four nonbypassable charges recognized under NEM 2.0 and the Power Charge Indifference Adjustment.
- For PG&E and SCE, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve an average Participant Cost Test (PCT) result of 1.2 over a 15-year timeframe for 2022 and 2023 installations. This approach achieves a discounted payback shorter than the 15-year interim successor tariff term proposed for PG&E and SCE.
- For SDG&E, the percentage reduction to the 2022 Non-CARE net electrification rate is calculated to achieve a discounted payback of 10 years, equal to the 10-year term proposed for the SDG&E interim successor tariff. The shorter payback period for SDG&E is due to the much higher average rates and the lack of a suitable electrification rate option.
- For both CARE and non-CARE customers, export compensation is fixed at the initial 2022 level, with no escalation over the interim successor tariff term (15 years for PG&E and SCE, 10 years for SDG&E).
- Netting period is instantaneous if practicable for the IOU. Otherwise, hourly netting should be performed.
- Customers should be allowed to remain on the interim successor tariff through the term of the interim successor tariff (15 years for PG&E and SCE, 10 years for SDG&E). The shorter duration for SDG&E is due to the accelerated payback period for these customers.
- Customers may voluntarily switch to the adopted end-state successor tariff at any point.
- For SCE and PG&E customers, the interim tariff is expected to yield fully discounted payback periods of 13-15 years and simple payback periods of 8-9 years. For SDG&E customers, the interim tariff is expected to yield fully discounted payback periods of 10 years and simple payback periods of 7.5 years. Details are shown in the tables at the end of this section.

The interim successor tariff should be required for new residential customers until the end-state successor tariff rate is implemented. The end-state successor tariff should be implemented as soon as practicable, and no later than January 1, 2024, once the IOUs have completed any necessary billing system modifications and both the Grid Benefit Charge and any authorized Market Transition Credits are able to be applied.

Modeling results for proposed Interim Successor Tariff

TURN used its cost effectiveness model to assess the impact of the proposed interim successor tariff on residential customers with both stand-alone solar and solar plus paired storage.[24] Sample results for SCE, PG&E and SDG&E customers are shown on the next page. In performing this analysis, TURN made the following assumptions:

- Residential customers take service on an electrification tariff and are assumed to be on a tariff with a baseline prior to adoption.
- Standalone renewable generator is assumed to be solar PV and is sized to serve 100% of first-year load.
- Export compensation is set at a defined percentage reduction to the 2022 Non-CARE net electrification rate, which excludes the following nonbypassable charges -- Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, and Power Charge Indifference Adjustment.
- The E3 SCE, SDG&E, and PG&E load shapes are assumed to be representative of average SCE, SDG&E, and PG&E residential customers prior to adoption.
- For SCE, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 34% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For PG&E, and with assumptions noted, the percentage reduction to the net electrification rate for a 15-year PCT result of 1.2 is approximately 44.5% for non-CARE customers. With no reduction to the electrification rate, it is not possible to achieve a PCT of 1.2 for CARE customers under a 15-year PCT.
- For SDG&E, there is an 85% reduction to the net electrification rate, which yields exports-weighted compensation of $0.03 per kWh. While this rate is low, it is slightly higher than the export-weighted ACC over the 10-year interim successor tariff term ($0.027 per kWh). In addition, the basic charge, in 2021 dollars, is increased to $1.50 per day for Non-CARE customers and $0.40 per day for CARE customers. With no reduction to the electrification rate, it is possible to achieve a 10-year discounted payback for CARE customers with the change to the basic charge described above.
- Hourly netting is modeled.
- The SCE electrification rate is TOU-D-PRIME, the PG&E electrification rate is EV-2, and the SDG&E electrification rate is EV-TOU-5 (modified with an increase in the basic charge).

[24] TURN's entire model was admitted to the evidentiary record (Ex. TRN-5) and was shared with all parties several times during the proceeding.

- Modeling assumes TURN's capital & operating cost assumptions and financing via a lease. Note that PCT results incorporate only the lease repayments expected to be made through the assumed term of the interim successor tariff.
- All other relevant modeling parameters are the same as those identified in TURN's model and described in testimony.[25]
- The steps to calculate the defined percentage reduction to the 2022 net electrification rate for exports compensation are as follows:

    - Step 1: Calculate imports and exports by TOU period over the interim successor tariff term using the relevant E3 load profile and assuming the standalone renewable generator is sized to serve 100% of first-year load.
    - Step 2: Calculate the standalone renewable generator cost components used in the discounted payback calculation for 2022 and 2023 installations. Costs, including any tax benefits and incentives, are those incurred/received over the interim successor tariff term.
    - Step 3: Calculate the compensation for the E3 load shape assuming the Non-CARE electrification rate for consumption, the 2022 Non-CARE net electrification rate in all years for exports, and the following NBCs assessed on imports: Competition Transition Charge, Public Purpose Programs, Nuclear Decommissioning Charge, Wildfire Fund Charge, Department of Water Resources Bond-Charge, and Power Charge Indifference Adjustment from full electrification rate.
    - Step 4: Calculate the customer's annual bills prior to and post adoption over the term of the interim successor tariff. Export compensation is the export rate in each TOU period applied to exports in each TOU period. Calculate annual bill savings for 2022 and 2023 installations.
    - Step 5: Calculate discounted payback result.
    - Step 6: For each eligible standalone renewable technology (i.e., solar PV), goal seek on the Non-CARE and CARE customer discounts to the 2022 net electrification rate export compensation to achieve a discounted payback equal to the interim successor tariff term, on average, for 2022 and 2023 installations.

[25] Ex. TRN-1, pages 20-30, 60-63.

TABLE 1
SCE 15-yr Tariff Standalone solar results
34% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.127	$ 0.127	0.40	0.38	1.12	15	8.6	8.8%	$ 548
2022	Non-CARE	34.00%	$ 0.127	$ 0.084	0.40	0.35	1.19	13	8.3	10.2%	$ 580
2023	CARE	2022 export rate (0%)	$ 0.127	$ 0.127	0.40	0.37	1.12	15	8.6	8.9%	$ 574
2023	Non-CARE	2022 export rate (34.0%)	$ 0.127	$ 0.084	0.40	0.35	1.21	13	8.2	10.4%	$ 615

TABLE 2
SCE 15-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.192	$ 0.192	0.59	0.58	1.00	18	11.5	6.3%	$ 471
2022	Non-CARE	34.00%	$ 0.192	$ 0.127	0.59	0.45	1.22	12	8.3	10.9%	$ 921
2023	CARE	2022 export rate (0%)	$ 0.192	$ 0.192	0.62	0.60	1.01	17	11.1	6.7%	$ 520
2023	Non-CARE	2022 export rate (34.0%)	$ 0.192	$ 0.127	0.62	0.47	1.24	11	8.1	11.5%	$ 978

TABLE 3
PG&E 15-yr Tariff Standalone solar results
44.5% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.141	$ 0.141	0.31	0.27	1.14	14	8.5	9.2%	$ 701
2022	Non-CARE	44.50%	$ 0.142	$ 0.079	0.31	0.26	1.19	13	8.5	10.1%	$ 696
2023	CARE	2022 export rate (0%)	$ 0.141	$ 0.141	0.30	0.26	1.15	14	8.4	9.4%	$ 702
2023	Non-CARE	2022 export rate (44.5%)	$ 0.142	$ 0.079	0.30	0.25	1.21	13	8.3	10.4%	$ 707

TABLE 4
PG&E 15-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	15-year RIM	15-yr PCT	Discounted Payback	Simple Payback	15-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.232	$ 0.232	0.42	0.41	1.00	18	12.1	6.1%	$ 553
2022	Non-CARE	44.50%	$ 0.232	$ 0.129	0.43	0.30	1.31	10	7.6	12.7%	$ 1,250
2023	CARE	2022 export rate (0%)	$ 0.232	$ 0.232	0.44	0.41	1.01	17	11.6	6.6%	$ 581
2023	Non-CARE	2022 export rate (44.5%)	$ 0.232	$ 0.129	0.45	0.30	1.34	10	7.3	13.3%	$ 1,290

TABLE 5

SDG&E 10-yr Tariff Standalone solar results

85% discount for Non-CARE customers, 0% for CARE

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.197	$ 0.197	0.33	0.22	1.32	10	7.4	9.0%	$ 769
2022	Non-CARE	85.00%	$ 0.197	$ 0.030	0.33	0.22	1.33	10	7.4	9.3%	$ 777
2023	CARE	2022 export rate (0%)	$ 0.197	$ 0.197	0.33	0.21	1.35	10	7.1	9.6%	$ 835
2023	Non-CARE	2022 export rate (85%)	$ 0.197	$ 0.030	0.33	0.20	1.38	10	7.1	10.1%	$ 838

TABLE 6
SDG&E 10-yr Tariff Paired storage results assuming same rate structure used for standalone solar

Year	Customer Type	Reduction to NonCARE Export Wted Rate (%)	Yr1 NonCare Expt Wted TOU Excl NBCs & PCIA	Exports Comp ($/kWh)	20-year TRC	10-year RIM	10-yr PCT	Discounted Payback	Simple Payback	10-year IRR	Year 1 Cost Shift
2022	CARE	0.00%	$ 0.239	$ 0.239	0.52	0.42	1.03	15	11.2	1.4%	$ 613
2022	Non-CARE	85.00%	$ 0.239	$ 0.036	0.52	0.31	1.31	10	7.5	9.1%	$ 1,205
2023	CARE	2022 export rate (0%)	$ 0.239	$ 0.239	0.55	0.44	1.05	15	10.7	2.2%	$ 676
2023	Non-CARE	2022 export rate (85%)	$ 0.239	$ 0.036	0.55	0.31	1.36	9	7.2	10.0%	$ 1,293

VERIFICATION

I, Nancy Rader, am the Executive Director of the California Wind Energy Association. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of "Opening Brief of the California Wind Energy Association" are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 31, 2021, at Berkeley, California.

/s/ *Nancy Rader*
Nancy Rader
Executive Director
California Wind Energy Association