**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)

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE PROPOSED DECISION REVISING NET ENERGY METERING TARIFF AND SUB-TARIFFS

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits these comments on the *Proposed Decision Revising Net Energy Metering Tariffs and Sub-Tariffs* ("PD"), issued by Administrative Law Judge ("ALJ") Kelly A. Hymes on December 13, 2021. Pursuant to the *Administrative Law Judge's Ruling Partially Granting the Coalition for Community Solar Access' Requests for an Extension of Time to File Comments and for an Increase in Page Limits for Opening and Reply Comments* issued on December 17, 2021 by Assistant Chief ALJ S. Pat Tsen on behalf of ALJ Hymes, CESA is timely submitting these comments on the PD.

I. <u>INTRODUCTION</u>.

CESA appreciates the opportunity to submit comments on the successor to the Net Energy Metering ("NEM") tariff. The NEM tariff has long provided the basis for the deployment of behind-the-meter ("BTM") renewable generation and energy storage systems in California, where its growth over the past decade and going forward will be crucial in making progress towards the state's 100% clean energy goal by 2045. To achieve the ambitious decarbonization goals of Senate Bill ("SB") 100, a combination of both in-front-of-meter ("IFOM") and BTM renewables and energy storage will be needed, with rapid-scale and unprecedented annual buildout rates such that one or the other alone cannot meet these goals. To the same end, California is aggressively pursuing efforts to decarbonize and reduce air pollutants from the transportation and building sectors through end-use electrification, which the Commission anticipates will add at least 15 TWh to statewide load in 2030.[1] Here again, BTM renewables and energy storage will play an important role in facilitating this electrification by helping to manage customer bills as well as to reduce infrastructure costs, which the PD seeks to encourage by allowing for oversizing of systems to accommodate 150% of current annual load.[2]

At the same time, the Commission has now led a two-year-long Emergency Reliability proceeding to bring additional capacity online for immediate reliability needs in Summers 2021-2023, with a large focus on enabling additional contributions from BTM resources through the Emergency Load Reduction Program ("ELRP").[3] An acute focus on ensuring supply resources meet load is anticipated to continue through 2026, as the Commission projects we need 11,500 MW of additional capacity, and related transmisison and distribution system upgrades, to meet reliability needs as the Diablo Canyon nuclear facility is decommissioned.[4] Local capacity in large load pockets, such as the Los Angeles Basin, will also be needed in order to retire polluting fossil fuel plants that have traditionally been located in disadvantaged communities. In order to meet these needs, leveraging BTM resources, particularly BTM renewables paired with energy storage,

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[1] *See* California Public Utilities Commission, *Utility Costs and Affordability of the Grid of the Future* published in May 2021 at 86, "The Reference scenario reflects sales assumptions from the 2019 IEPR Mid Demand case. […] While the Reference case has 15 TWh of CAISO-wide vehicle and building electrification load in 2030, the High Electrification scenario adds another 18 TWh of electrification load by 2030 for a total of 33 TWh."

[2] PD at 82.

[3] *See* D.21-12-015.

[4] *See* D.21-06-035.

for additional grid services, such as resource adequacy ("RA"), will be an important part of the toolkit to meet the state's electric needs while achieving our climate goals.

CESA appreciates the Commission's focus on energy storage in the PD and acknowledgement that BTM hybrid generation paired with storage provides additional grid value and ratepayer benefits.[5] While the PD intends to encourage storage adoption by moving to a Net Billing Tariff ("NBT"), where the export compensation rate is decoupled from retail rates and instead tied to more granular Avoided Cost Calculator ("ACC") values to align exports to times that are the most valuable to the grid, the NBT as currently proposed falls short of achieving these ends by adopting a fixed charge in the form of a Grid Participation Charge ("GPC"), modifying the netting period to one that is instantaneous, and creating uncertainty related to the export compensation rate with updates to the ACC values. As a result, despite the Commission's intent to evolve the NEM to NBT and encourage energy storage adoption, the current proposal would have the ultimate effect of deterring customer participation in the new tariff and likely stalling the growth of BTM renewables and energy storage. Therefore, while the Commission has taken steps to encourage storage in the PD, the addition of fixed charges to the tariff eliminates the financial viability for customers to participate in this NBT. Instead, customers will be encouraged to adopt non-export BTM systems, unable to provide additional export capacity or related grid services, or discouraged from adopting BTM systems at all, which can also discourage electrification as rates increase in the next ten years.[6]

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[5] PD at 85.

[6] *See* California Public Utilities Commission, *Utility Costs and Affordability of the Grid of the Future* published in May 2021 at 8, "By 2030, bundled residential rates are forecasted to be approximately 12 percent [for Pacific Gas & Electric ("PG&E")], 10 percent [for Southern California Edison ("SCE")], and 20 percent [for San Diego Gas & Electric ("SDG&E")] higher, respectively, than they would have been if 2020 actual rates for each IOU had grown at the rate of inflation."

Since NEM (and now the NBT) has been and will be the foundation and immediate value proposition for customers installing BTM renewable and energy storage systems, CESA offers the following feedback and recommendations to make the tariff workable in supporting the sustainable growth of BTM renewable and energy storage systems while balancing against the other guiding principles of successor tariff development and adoption:

- Proposed fixed charges reduce customers' ability to self-supply electricity on NBT systems compared to other load-reducing measures and have other cascading impacts.
- Certainty in the export compensation rate ("ECR") is necessary to allow customers to make informed decisions and finance their systems.
- Glidepaths will be essential for customer transitions.
- The energy storage incentive for current NEM 2 customers should remain at $0.20/Wh for the first two years of implementation.
- Retroactive policy changes and mandatory transitions for NEM 1 and 2 customers should be removed.

In addition to the aforementioned concerns, the Commission should take into consideration the current supply chain constraints for lithium-ion batteries, which could create a major disruption in the immediate term until manufacturing supplies are increased to achieve the scale necessary to meet the growing demand from the BTM customer segment. Battery manufacturers have major plans over the next 1-3 years to rapidly increase their production capacity to meet exponential and global demand for lithium-ion batteries to serve the electric vehicle ("EV") market, utility-scale IFOM energy storage market, and customer-sited BTM energy storage market, but the current constraints impacting supply chains of all sectors have made current-day and near-term battery supplies expensive and difficult to access. To avoid a complete stall of the BTM energy storage deployments under the NBT, CESA thus recommends reasonable glidepaths and immediate measures to extend the optional storage rebate period for NEM 2 customers.

Overall, with the above modifications, CESA believes that the NBT can better encourage customers to adopt BTM renewables and energy storage to meet California's decarbonization and reliability goals. However, if these modifications are not adopted in a revised PD, an Alternate PD may be needed to ensure that there is a future of customer-sited storage.

II. PROPOSED FIXED CHARGES REDUCE CUSTOMERS' ABILITY TO SELF-SUPPLY ELECTRICITY ON NBT SYSTEMS COMPARED TO OTHER LOAD-REDUCING MEASURES AND HAVE OTHER CASCADING IMPACTS.

The NBT outlined in the PD includes a GPC for residential customers, excluding low-income customers, which would be \$8/kW "based on the number of kilowatts installed in a residential customer's system,"[7] though it is unclear whether system size would be based on the generation system alone or the combined size of the generation and storage system. Given that most parties originally proposed these types of fixed charges be based on the size of the generation system alone, CESA assumes that the Commission is intending to apply charges based solely on the size of the generation system but asks for clarification. Notwithstanding this ambiguity, the fixed charge in itself presents a number of concerns, especially considering the magnitude of the charge, which stands at \$40 per month for a standard 5-kW rooftop solar system. Such a large charge will drastically reduce the incentive to participate in the NBT or install BTM renewable generation or BTM hybrid renewable generation and energy storage systems altogether.

The GPC will eliminate financial viability for many customers to install BTM generation and energy storage, and consequently, will reduce the financial viability of electrifying. As

[7] PD at 125.

highlighted by Sierra Club in testimony, electrification is key to meeting California's climate goals, and BTM generators can help encourage electrification by providing further bill savings for customers that electrify.[8] Electrification rates can also encourage use of load in ways that support the grid by providing high differential time-of-use ("TOU") rates with a fixed charge component. For example, SDG&E's EV-TOU-5 rate includes On-Peak rates of $0.33-0.56/kWh, Off-Peak rates of $0.31-0.33/kWh, and Super Off-Peak rates of $0.08-0.09/kWh, and a $16 monthly service fee. High variation TOU rates help to encourage electricity use in Super Off-Peak rates, and a modest fixed charge can help reduce volumetric rates. However, the GPCs proposed in the PD are significantly larger than, and must be paid on top of, the fixed charge components of current electrification rates. The Commission has encouraged future electrification load growth in the PD by allowing customers to size their systems to 150% of current load but eliminates financial viability of oversizing for many customers by basing the GPC off the size of the system being installed.[9]

While customers installing BTM DERs should not create burdensome cost shifts for non-participating customers, CESA does not support a narrow application of the GPC exclusively to NBT customers. There is a larger discussion emerging in the state surrounding rising electricity costs due to increased transmisison and distribution system buildout and wildfire-related infrastructure costs, both of which are lumpy and fixed investments. For residential customers and some commercial customers, California has long passed through these fixed costs in volumetric rates, which has made retail rates two to four times higher than the marginal cost of service.[10]

[8] *See* SCL-02 (Camp) at p. 5-6.

[9] PD at 82.

[10] Borenstein, et al. "Designing Electricity Rates for An Equitable Energy Transition" published in February 2021 at 5. Available at: https://haas.berkeley.edu/wp-content/uploads/WP314.pdf.

Electrification rates have begun to introduce fixed charge components; however, scholars have highlighted potential needs to re-build California rates from the bottom-up to include fixed costs for customers based on income or potentially leverage taxpayer dollars to subsidize these costs.[11] This can also help encourage electrification by having volumetric portions of bills based on marginal prices, helping electricity compete with the costs of other fuels such as gasoline and natural gas. An important larger conversation needs to be had, which includes the impacts of BTM generation on other ratepayers, but also should consider the holistic picture of our electric system and rate structures today.

Additionally, many parties, including CESA, have highlighted that BTM NEM generators are Qualifying Facilities ("QF") in accordance with the Public Utility Regulatory Policies Act ("PURPA").[12] When considering changes to rates that affect PURPA QFs, all customers with similar load characteristics need to be considered as well, not solely PURPA generators.[13] Similarly and importantly, attempting to recover retail revenue lost to self-consumption through a GPC, as proposed in the PD, appears to be violating the determinations made by the Federal Energy Regulatory Commission ("FERC") that self-supply for "station power," and by extension, for onsite electricity needs, should not be treated as a retail sale of energy.[14] CESA also sees flaws in having self-supplied energy from onsite generation assessed retail fixed charges when the self-generation never actually uses the transmission and distribution system.

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[11] *Ibid*.

[12] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,888, *order on reh'g sub nom*. Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

[13] 18 C.F.R. § 292.305(a)(2).

[14] *Calpine Corp. v. F.E.R.C.*, 702 F.3d 41, 43 (D.C. Cir. 2012); *California Indep. Sys. Operator Corp.*, 125 F.E.R.C. ¶ 61,072 (2008).

In sum, given the many issues that should be considered when assessing appropriate fixed charges for customers, it is more appropriate to consider modifications to electrification rates or other NBT eligible rates in the General Rate Cases ("GRCs") of each utility.

III. CERTAINTY IN THE EXPORT COMPENSATION RATE IS NECESSARY TO ALLOW CUSTOMERS TO MAKE INFORMED DECISIONS AND FINANCE THEIR SYSTEMS.

In creating an NBT that uses the ACC to determine the ECR, the PD states that exports "for the first five years following a customer's interconnection date will be based on a five-year schedule of values for each hour from the Avoided Cost Calculator,"[15] adopted as of January 1 of the customer's year of interconnection. However, after five years, the ECR will be updated yearly based on the ACC adopted as of January 1 each year. While basing exports on the ACC helps to more granularly value exports on time of day, the lack of certainty on what ECR will be after only 5 years for what is typically a 20- or 25-year investment makes it impossible for customers to make informed investment decisions and finance their systems.

The ACC was designed as a tool to value DER energy output that results in either load reduction or export in a technology-neutral manner. The ACC is thus designed to encompass values of technologies including BTM generation, energy storage, demand response ("DR"), and energy efficiency ("EE"). However, while used a tool to set appropriate compensation for programs such as EE programs, the ACC was not designed to consider its impacts on any single program that uses it. Instead, programs have separately adopted updated versions of the ACC or adjusted payments based on updated ACCs. In D.16-06-007, the Commission adopted an annual update cycle to incorporate accurate inputs and assumptions and create an up-to-date tool to reference across proceedings, but stated that "because the process to update the calculator will

[15] PD at 114.

occur outside any proceeding using the calculator, there should be no direct effect on program administrators or participants."[16] CESA agrees that it is prudent to conduct this modeling exercise on a frequent basis to understand the evolution of our electric system and how to deploy DERs in the most valuable way. However, the use of the ACC for the purposes of the NBT requires careful consideration of its impact on the tariff's guiding principles and goals, as well as for the purposes of consumer protection and understanding. The PD claims that the ACC does not fluctuate dramatically, stating that "except for the 2020 version, the Avoided Cost Calculator has consistently reflected the value of exported energy, year after year."[17] While that has traditionally been true, the shift to clean energy, shutdown of Diablo Canyon and other fossil fuel plants, growing extreme weather events, and wildfire may change the inputs and assumptions we use in the ACC and subsequent output values.

Given that BTM solar systems can have a lifetime of 25 years and storage systems can last 15 years, a mere 5-year lock-in of ACC ECR values does not give enough certainty for customers to make informed investments. Currently, D.20-08-001 requires solar providers selling systems to residential customers to estimate bill savings over 20 years using standard inputs and assumptions.[18] Installers or solar developers could attempt to predict 20-year savings using the most up-to-date ACC, under the assumption that values will remain relatively consistent. However, real ECRs may be very different than predicted, raising concerns over false advertising and consumer protection. Long-term, predictable returns are typically needed for financing and leasing across the energy industry. To the same end, IFOM generation and storage resources often sign power purchase agreements ("PPAs") with specified payment rates for 20 years that are locked in,

[16] D.16-06-007 at 7.

[17] PD at 90.

[18] D.20-08-001 Ordering Paragraph ("OP") 2.

even if energy prices or the cost of a particular technology (*e.g.*, solar) fall or rise. A larger level of certainty or bounds on the amount the ECR may fluctuate in a given year can help customers predict potential scenarios to design a system and financing that works for them. For example, the Sacramento Municipal Utility District ("SMUD") has reformed their NEM program, moving to a net billing structure with lower ECRs. However, their ECR will be revised every 4 years, with a maximum change between ECRs of +/- 30%.[19] This will give customers more certainty to predict returns on their systems yet provides room for values to fluctuate within reasonable bounds to reflect the changing value of exported energy and grid conditions. Given that the ACC updates every year instead of every 4 years, CESA recommends setting a bound of +/- 10% on the amount the ECR can change each year as the ACC updates.

In addition to the certainty associated with ECR values on a longer-term basis, CESA believes that the PD creates significant uncertainty with the adoption of instantaneous netting, where data from the import and export channels of the customer meter are used separately in bill calculations rather than netted for each meter interval. Our concerns with this aspect of the NBT proposal are around the technical feasibility of such data collection and calculations without significant costs or material impacts to project timelines, as well as with how any solar and storage providers would be able to calculate accurate electric bill savings estimates using a set of standardized inputs and assumptions, pursuant to D.20-08-001. Furthermore, the use of instantaneous netting appears to contradict the Commission's previous decision (D.16-12-039) that rejected a Petition from Calpine Corporation to equate the netting calculation methodology

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[19] "Exhibit Agenda Item 1: SMUD 2021-2022 Rate Proposal overview, including proposed rate increases and new Solar and Storage Rate and programs" presentation on May 18, 2021 at the SMUD Board Finance & Audit Committee and Special SMUD Board of Directors Meeting at Slide 40. Available at: https://www.smud.org/-/media/Documents/Corporate/About-Us/Board-Meetings-and-Agendas/2021/May/2021-05-18-Finance-and-Audit-Exhibit-to-Agenda-Item-1---Jennifer-Davidson-and-Eric-Poff.ashx.

for station power for IFOM generating facilities with that of the NEM successor tariff at the time. Ultimately, the Commission found that "the differences between customer-generators who are eligible for the NEM successor tariff and merchant generation facilities paying for station power are both many and significant" and proceeded to list out the many and most relevant ones.[20] Recognizing these differences, CESA finds it inconsistent that the same logic would not apply in establishing a netting provision that is more punitive than the 15-minute netting provision for station service for IFOM wholesale generators that are integrated in a more dynamic and complex market. At minimum, the netting provision should be modified from instantaneous to 15 minutes but given the simpler use case of NBT resources supporting onsite customer load, the Commission would be justified in establishing daily netting provisions. Additionally, it is unclear how instantaneous netting would be applied to Virtual NEM ("VNEM") customers. The Commission affirms in the PD that there is on-site consumption of electricity produced by VNEM generators,[21] but given that VNEM generator meters measuring output are separate from individual tenant or common use meters measuring customer usage, it is unclear how VNEM output would be netted with onsite consumption in an instantaneous netting tariff.

IV. <u>GLIDEPATHS WILL BE ESSENTIAL FOR CUSTOMER TRANSITIONS.</u>

CESA appreciates the inclusion of a Market Transition Credit ("MTC") for residential customers to help transition the market to the successor tariff, which will help customers deploy additional BTM systems as prices are further reduced across time and as energy storage manufacturing ramps up to meet demand. However, additional glidepath considerations should be incorporated in a revised NBT that recognizes the current and foreseeable situation of supply chain

[20] D.16-12-039 at 4-5.

[21] PD at Findings of Fact ("FOF") 182.

disruptions and intense competition for limited battery supplies among different facets of the energy storage industry as well as the EV industry. In particular, building off our broader supply chain concerns above, the Commission should consider that BTM solar developers and installers, particularly small, local installers, will often have trouble competing against larger IFOM developers or EV manufacturers for an already limited battery supply. Additionally, in 2020, only 8% of Californian customers that installed BTM solar attached storage to it.[22]

Therefore, a transition credit that allows for customers to pay for more expensive storage or find cost-effective standalone solar options will be crucial to maintain the workforce of the DER industry as battery supply ramps up.[23] As mentioned in testimony from the Solar Energy Industries Association ("SEIA") and Vote Solar, Hawaii saw a 60% drop in permit requests for BTM solar installations after NEM reform was implemented in 2016, with most installers laying off a third of their workforce.[24] A glidepath will prevent shocks to the market and will ensure "that the market that customer-sited renewable distributed generation continues to grow sustainably."[25] Overall, CESA commends the Commission on promoting energy storage in the PD but believes a glidepath is needed for all customers to help industry ramp up and adapt and recommends extending the MTC to non-residential customers.

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[22] "Behind-the-Meter Solar + Storage: Market data and trends" presented by Lawrence Berkeley National Laboratory on July 29, 2021 at slide 7. Slides available at: https://emp.lbl.gov/publications/behind-meter-solarstorage-market-data

[23] California Solar and Storage Association ("CALSSA") Opening Brief at 2-3.

[24] SVS - 01 (Giese) at p. 8, lines 14-21.

[25] Cal. Pub. Util. Code § 2827.1(b)(1).

V. THE ENERGY STORAGE INCENTIVE FOR CURRENT NEM 2 CUSTOMERS SHOULD REMAIN AT $0.20/WH FOR THE FIRST TWO YEARS OF IMPLEMENTATION.

CESA supports a voluntary incentive program to encourage NEM 2 customers to install energy storage systems. However, the timeline provided in the PD states that "[i]f an existing NEM 2.0 tariff customer voluntarily switches to the successor tariff during the first year of implementation, they will receive a $0.20/Wh storage rebate."[26] CESA understands that this would be the first year of implementation of the successor tariff in 2023. However, given current supply chain constrains and the time it will take to conduct outreach to existing NEM 2 customers, CESA recommends that the first-year incentive amount of $0.20/Wh be extended to customers that transition in the first two years of the implementation of the NBT, 2023 and 2024. Furthermore, this incentive should be extended to customers moving to either the NBT or another non-NEM tariff for which the customer is eligible, such as a non-export tariff, to further incentivize the addition of storage and movement away from NEM 2. Afterwards, a yearly stepdown of 25% for the next 3 years will encourage customers to transition quickly to take advantage of higher incentives. As highlighted above, the energy storage industry is still beginning to scale, and costs of individual pieces of equipment remain high while manufacturing supply is still growing to meet demand. Extending the first-year incentive level and overall incentive program by one year while enabling customers to move to additional alternative tariffs will encourage more customers to install storage.

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[26] PD at 150.

VI. RETROACTIVE POLICY CHANGES AND MANDATORY TRANSITIONS FOR NEM 1 AND 2 CUSTOMERS SHOULD BE REMOVED.

CESA is disappointed to see that the PD includes retroactive changes to NEM 1 and 2 that shorten the NEM 1 and 2 terms for non-CARE residential customers from 20 years to 15 years,[27] as doing so will severely undermine customer trust in the Commission and general state energy programs. While NEM 1 and 2 systems may be fully "paid back" in less than 15 years for many residential customers, many customers did not pay for systems upfront in cash. Instead, solar leasing and PPAs have become common and often include 20- or 25-year fixed terms. For these customers in particular, shortening grandfathering periods can impact the affordability of their NEM system and their ability to payback these systems, given that contracts were structured under the 20-year tariffs outlined by the Commission.[28] This is a consumer protection issue that violates principle (c), outlined in D.21-02-007, that a successor tariff should enhance consumer protections for customer generators, given that consumers had no foresight to anticipate that these terms could change. Additionally, setting the precedent that terms of previous tariffs can be changed will discourage future customers from investing in DERs under the successor tariff, knowing that future reforms could change their terms at any time.

VII. CONCLUSION.

CESA appreciates the opportunity to submit these comments on the PD and looks forward to working with the Commission and other stakeholders in this proceeding.

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[27] PD at 149.

[28] *See* D.14-03-041 at OP 1 and D.16-01-044 at Conclusions of Law ("COL") 14, which established 20-year terms for NEM 1 and 2, respectively.

Respectfully submitted,

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