STATE OF CALIFORNIA EDMUND Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 14-07-002:

This is the proposed decision of Administrative Law Judge Anne E. Simon. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's January 28, 2016 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJ SIMON (Mailed 12/15/15)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

(See Appendix D for List of Appearances.)

DECISION ADOPTING SUCCESSOR TO NET ENERGY METERING TARIFF

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DECISION ADOPTING SUCCESSOR TO NET ENERGY METERING TARIFF

Summary

This decision implements some of the provisions of Assembly Bill (AB) 327 (Perea), Stats. 2013, ch. 611. AB 327, among other things, adds Section 2827.1 to the Public Utilities Code, requiring the Commission to develop "a standard contract or tariff, which may include net energy metering (NEM), for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation."

In this decision, the Commission:

- Ensures that customer-sited renewable distributed generation (DG) continues to grow sustainably by creating a successor to the existing NEM tariff that includes a new NEM tariff, with modifications;
- Follows the fundamental approach to residential rate reform expressed in Decision (D.) 15-07-001, by
    - Declining to impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM residential customers while the Commission is working on how, if at all, any such fees should be developed for residential customers;
    - Continuing to rely on the minimum bill established in D.15-07-001 as a mechanism for ensuring that customers using the NEM successor tariff contribute through their bill payments to the costs of maintaining the services of the electric grid for all customers;
    - Maintaining the requirement that non-residential NEM customers pay any demand charges, standby fees, or similar fixed charges that are part of the underlying rate for their customer class, regardless of the requirements of the NEM tariff under which they receive service.

- Continues the basic features of the current NEM tariff into the successor NEM tariff, but makes changes that:
    - Require customers installing customer-sited renewable distributed generation systems to pay a reasonable interconnection fee to the interconnecting investor-owned utility (IOU);
    - Require customers on the NEM successor tariff to pay the nonbypassable charges that are levied on each kilowatt-hour (kWh) of electricity the customer obtains from the IOU in each metered time interval, regardless of the monthly netting of the kWh obtained from the IOU and exported to the grid by the customer;
    - Require residential NEM successor tariff customers interconnecting on or after January 1, 2018 to take service on a time of use (TOU) rate, which may include participation in a TOU pilot study;
- Extends eligibility for the NEM successor tariff to customer-sited facilities larger than one megawatt in size, so long as the customer pays all Rule 21interconnection study and distribution system upgrade fees for the facility;
- Establishes minimum warranty and equipment safety requirements for installations for customers taking service under the NEM successor tariff;
- Determines that the Multifamily Affordable Housing Solar Roofs Program established by recently enacted AB 693 (Eggman), Stats. 2015, ch. 582, will be included as one element of the Commission's plan for providing alternatives designed for growth of customer-sited renewable distributed generation among residential customers in disadvantaged communities;
- Determines that one element of the Commission's plan for providing alternatives designed for growth of customer-sited renewable distributed generation among residential customers in disadvantaged communities will be an expansion of the existing Virtual Net Metering (VNM) tariff;

- Determines that the VNM and net metering aggregation (NEMA) tariffs should be maintained and updated consistent with the provisions of the NEM successor tariff established by this decision;
- Provides that customer-generators may continue to take service under the NEM successor tariff established by this decision for 20 years from the year of interconnection of the customer's system;
- Determines that a better understanding of the impact of customer-sited distributed resources on the electric system will be developed from work currently under way but not yet completed in other Commission proceedings, including but not limited to the distribution resources plan proceeding (Rulemaking (R.) 14-08-031), the integrated distributed energy resources proceeding (R.14-10-003), and the proposed rulemaking on preliminary issues in setting TOU rates;
- Identifies the year 2019, which the Commission has selected as the target for beginning default TOU rates for residential customers, as the appropriate time to review the NEM successor tariff established by this decision, including the programs that provide alternatives for growth of renewable distributed generation among residential customers in disadvantaged communities, and to make any adjustments to the successor tariff, including possible changes to the tariff design, and related programs that are necessary at that time;
- Authorizes the Director of Energy Division to direct the development, in consultation with the parties, of a method of evaluating whether the NEM successor tariff results in growth of customer-sited renewable distributed generation, consistent with the methodology established by this decision;
- Authorizes the Director of Energy Division to take appropriate steps to prepare for further work in this proceeding, including but not limited to, convening workshops led by Energy Division staff, producing staff reports, developing information for potential NEM successor tariff customers, and similar work;

- Requires Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, each to submit a Tier 2 advice letter, with its NEM successor tariff, VNM tariff, and NEMA tariff, in conformity with the provisions set out in this decision, within 30 days after the effective date of this decision;
- Determines that in order to fully develop the alternatives for residential customers in disadvantaged communities, and more fully develop the means for effectuating consumer protection and evaluation measures for the NEM successor tariff, a second phase of this proceeding should be initiated.

This proceeding remains open.

1. Procedural History

The Order Instituting Rulemaking (OIR) for this proceeding was adopted by the Commission on July 10, 2014.[1] A prehearing conference (PHC) was held on October 30, 2014.[2] The Scoping Memo and Ruling of Assigned Commissioner (Scoping Memo) was issued on January 23, 2015. Because several strands of work have been under way simultaneously throughout the proceeding, this

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[1] Comments on the OIR were filed on August 18, 2014 by California Energy Storage Alliance (CESA); California Farm Bureau Federation (Farm Bureau); CAlifornians for Renewable Energy (CARE); Clean Coalition; Community Alliance with Family Farmers (CAFF); Interstate Renewable Energy Council (IREC); Local Government Sustainable Energy Coalition (LGSEC); Marin Clean Energy (MCE); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); The Alliance for Solar Choice (TASC); and The Utility Reform Network (TURN).

Reply comments were filed on August 26, 2014 by California Environmental Justice Alliance (CEJA); California Solar Energy Industries Association (CALSEIA); IREC, Office of Ratepayer Advocates (ORA); PG&E; SCE; Solar Energy Industries Association (SEIA); TASC; and Wal-Mart, Sam's West, and the University of California (jointly; collectively, Walmart).

[2] PHC statements were filed on October 27, 2014 by CALSEIA; SEIA; TASC and The Vote Solar Initiative (Vote Solar), jointly; CARE; CEJA and Sierra Club (jointly); Net Energy Metering Public Agency Coalition (NEM-PAC); IREC; ORA; PG&E; SCE; and SDG&E.

procedural history is organized according to the topics addressed, each in chronological order.

1.1. Public Tool

The Public Tool, as it came to be called in this proceeding, is a spreadsheet model that provides a common framework for parties to use to test and evaluate options for the net energy metering (NEM) successor tariff. Its development by Energy Division staff and consultants to staff[3] spanned more than a year, beginning prior to the initiation of this proceeding.[4]

Energy Division staff held a workshop on April 23, 2014, to discuss the concepts involved in developing the Public Tool and the capabilities that the Public Tool should have. Following the workshop, staff received informal comments from a number of stakeholders interested in the proposed Public Tool.

Energy Division staff held another workshop on August 11, 2014, after the OIR for this proceeding was adopted. In response to the Administrative Law Judge's (ALJ) Ruling Seeking Post-Workshop Comments (September 5, 2014), 17 parties filed comments on October 1, 2014; 13 parties filed reply comments on October 20, 2014.[5] An informal webinar facilitated by the consultants was held

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[3] Energy + Environmental Economics are the consultants for the development of the Public Tool.

[4] Energy Division staff maintains a section of the Commission's web site dedicated to the Public Tool. It may be found at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.

[5] Comments were filed by 350 Bay Area, CESA, CEJA, Farm Bureau, CARE, Clean Coalition, CAFF, Inland Empire Utilities Agency, IREC, ORA, PG&E, SCE, SDG&E, Sierra Club, TASC, and Vote Solar.

Reply comments were filed by Farm Bureau, CEJA, Clean Coalition, CAFF, Inland Empire Utilities Agency, IREC, ORA, PG&E, SCE, SDG&E, Sierra Club, Silicon Valley Leadership Group (SVLG), and jointly by TASC, CALSEIA, Vote Solar, and SEIA.

December 2, 2014, to further familiarize parties with the status of developing the Public Tool.

The work on the draft of the Public Tool was formalized by the ALJ's Ruling Adopting Specifications for Further Development of Public Tool (December 12, 2014), which identified both elements that would be incorporated into the draft Public Tool and elements that would not be. Energy Division staff held another public workshop on December 16, 2014 to review and discuss the final proposed approach, functionality, and user interface of the Public Tool, prior to the issuance of the draft Public Tool.

Energy Division staff held a workshop on March 30, 2015, to demonstrate the use of the draft version of the Public Tool. Comments on the draft version of the Public Tool were requested in the ALJ's Ruling Seeking Comment on Draft Version of Public Tool (April 15, 2015), and were filed on April 28, 2015.[6]

The Public Tool became available for use through the ALJ's Ruling Setting Specifications for the Final Version of the Public Tool and Accepting into the Record the Final Version of the Pubic Tool (June 4, 2015).[7] Also on that date, the *Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract: Staff Paper Demonstrating How to Use the Public tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance with Assembly Bill 327* (*Staff Tariff*

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[6] Comments were filed by CEJA, CESA, Clean Coalition, Custom Power Solar, Federal Executive Agencies (Federal Agencies), ORA, PG&E, SCE, SDG&E, Sierra Club, TURN, Vote Solar, and by CALSEIA, SEIA, and TASC jointly. Reply comments were not allowed.

[7] Subsequent changes were made to the Public Tool, responding both to minor errors that were detected in the final version and to the changes in residential rate design announced in Decision (D.) 15-07-001; they were addressed in the ALJ's Ruling Providing Further Instructions for Parties' Proposals and Accepting into the Record Certain Updates to the Public Tool (July 20, 2015).

Paper) was accepted into the record by the ALJ's Ruling (1) Accepting into the Record Energy Division Staff Papers on the Assembly Bill (AB) 327 Successor Tariff or Contract; (2) Seeking Party Proposals for the Successor Tariff or Contract; and (3) Setting a Partial Schedule for Further Activities in this Proceeding (Proposal Ruling).

1.2. Policy Issues and Parties' Proposals

In response to the ALJ's Ruling Seeking Comment on Policy Issues Associated with the Development of Net Energy Metering Standard Contract or Tariff (February 23, 2015), parties filed comments on March 16, 2015, and reply comments on March 30, 2015.[8]

As part of the ALJ's Proposal Ruling, the *Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327* (*Staff Disadvantaged Communities Paper*) was accepted into the record. In response to the Proposal Ruling, parties filed their proposals for a successor tariff or

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[8] Comments were filed by 350 Bay Area, Agricultural Energy Consumers Association (AECA); CALSEIA, SEIA, TASC and Vote Solar, jointly (collectively, Joint Solar Parties); CESA, California Certified Organic Farmers (CCOF); CEJA and Greenlining Institute (Greenlining), jointly; California Municipal Utilities Association (CMUA); Farm Bureau; Clean Coalition; Coalition of California Utility Employees (CUE); GRID Alternatives; Independent Energy Producers (IEP); IREC; MCE, National Resources Defense Council (NRDC), NRG Energy (NRG), ORA, PG&E, SCE, SDG&E, Sierra Club, SVLG; TURN, NEM-PAC; and Walmart.

Reply comments were filed by 350 Bay Area, AECA, CEJA and Greenlining, CCOF, Farm Bureau, Clean Coalition, CMUA, CUE, IEP, IREC, Joint Solar Parties, NEM-PAC, ORA, PG&E, SCE, SDG&E, Sierra Club, and Walmart.

contract, as well as proposals for alternatives for residential customers in disadvantaged communities.[9]

1.3. Evidentiary Hearings

Requests for evidentiary hearings were made by CARE, SCE, and PG&E and SDG&E jointly on August 10, 2015. On September 1, 2015, the ALJ's Ruling Setting Evidentiary Hearings and Setting a Schedule for Further Activities Prior to Evidentiary Hearings (Hearing Ruling) was issued. The Hearing Ruling identified the issues on which hearings would be held and set the schedule for submission of testimony.[10]

A second PHC was held on September 18, 2015, in accordance with the ALJ's Ruling on Prehearing Conference Process and Requesting Prehearing Conference Statements (September 4, 2015). PHC statements were filed by 20 parties.[11] The PHC was followed by the ALJ's Ruling Providing Additional

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[9] Proposals for both a successor tariff and alternatives for customers in disadvantaged communities were filed by ORA, PG&E, SCE, SDG&E, SEIA/Vote Solar, and TURN.

Proposals addressing only a successor tariff were filed by CALSEIA, CARE, Farm Bureau, Federal Agencies, NRDC, Sierra Club, and TASC.

Proposals addressing only alternatives for residential customers in disadvantaged communities were filed by CEJA, GRID Alternatives, and IREC.

[10] The issues identified for hearing were:

1. The basis for projections of prices of rooftop solar installations that are different from those used in the Public Tool (CALSEIA);

2. The basis for the investor-owned utilities' proposed charges in the successor tariff for interconnection of small systems (PG&E; SCE; SDG&E); and

3. The basis for any proposed demand charges, capacity fees, standby charges, access fees, use charges, or other fixed charges for the successor tariff that are different from the assumptions used in the Public Tool (NRDC; ORA; PG&E; SCE; SDG&E).

[11] They are: CALSEIA, CEJA, Clean Coalition, MCE, NEM-PAC, NRDC, ORA, PG&E, SCE, SDG&E, Sierra Club, TASC, TURN, Wal-Mart, and SEIA/Vote Solar.

Instructions for Testimony, Rebuttal Testimony, and Other Documents (September 25, 2015).

Direct testimony was served by CALSEIA, NRDC, ORA, PG&E, SCE, and SDG&E on September 21, 2105. Rebuttal testimony was served by Joint Solar Parties, PG&E, and SDG&E on September 30, 2015. The evidentiary hearing was held October 5-7, 2015. Opening briefs were filed October 19, 2015; reply briefs were filed October 26, 2015.[12]

1.4. Assembly Bill 693

On the final day of evidentiary hearings in this proceeding, the Governor signed into law AB 693 (Eggman), Stats. 2015, ch. 582. Among other things, AB 693 creates the Multifamily Affordable Solar Roofs Program, and provides that

> adoption and implementation of the Multifamily Affordable Housing Solar Roofs Program may count toward the satisfaction of the commission's obligation to ensure that specific alternatives designed for growth among residential customers in disadvantaged communities are offered as part of the standard contract or tariff authorized pursuant to paragraph (1) of subdivision (b) of Section 2827.1.
> (Pub. Util. Code § 2870(b)(1).[13]

[12] Opening briefs were filed by Joint Solar Parties, NRDC, ORA, PG&E, SCE, SDG&E, and TURN.

Reply briefs were filed by CALSEIA, SEIA, and TASC (jointly); CEJA; ORA; PG&E; SCE; SDG&E; Sierra Club; and TURN

[13] All further references to sections are to the Public Utilities Code, unless otherwise specified.

On October 21, 2015, the ALJ issued a Ruling Seeking Comment on Assembly Bill 693. Comments were filed November 2, 2015; reply comments were filed November 9, 2015.[14]

This matter was submitted on November 9, 2015.

2. Discussion

2.1. Introduction and Plan of this Decision

This discussion begins with a brief review of the history of the NEM program. The complex context in which the NEM successor tariff is being determined is addressed in three parts: the specific requirements of AB 327; the developments in the Commission's residential rate redesign process; and the work the Commission has undertaken in relation to improving the available information and, ultimately, policy choices about renewable distributed energy resources.

The thorough and extensive proposals made by the parties are summarized in three parts.[15] The first section covers proposals for the successor tariff or contract itself. The second section covers proposals for alternatives for

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[14] Comments were filed by Brightline Defense Project (Brightline) and Salvadoran American Leadershp and Educational Fund (SALEF), jointly; CEJA; Center for Sustainable Energy (CSE); Custom Power Solar; Everyday Energy; Greenlining; GRID Alternatives; IREC; Joint Solar Parties; Multifamily Affordable Solar Housing (MASH) Coalition; ORA; PG&E; SCE; and TURN.

Reply comments were filed by CEJA, CSE, Everyday Energy, Greenlining, GRID Alternatives, IREC, Joint Solar Parties, MASH Coalition, ORA, PG&E, SDG&E, Sierra Club, and TURN.

[15] The Commission appreciates the extensive efforts of the parties in vetting the Public Tool; in developing and testing their proposals; in commenting on proposals and policy issues; and in participating in the evidentiary hearing. All proposals and comments have been taken into consideration in the development of the NEM successor tariff put forth in this decision, though not all party contributions are discussed in this decision.

growth among residential customers in disadvantaged communities. The third covers proposals related to safety, consumer protection, and customer education.

2.2. Overview of NEM Program

The NEM program was established by Senate Bill (SB) 656 (Alquist), Stats. 1995, ch. 369, in 1995, and codified in Section 2827 of the Public Utilities Code. From 1996 to the present, customers with eligible renewable generation facilities installed behind the customers' meters (referred to as "customer-generators" in § 2827) that meet certain technical requirements have been able to choose to participate in a NEM tariff.[16]

Under NEM, customer-generators offset their charges for any consumption of electricity provided directly by their renewable energy facilities and receive a financial credit for power generated by their on-site systems that is fed back into the power grid for use by other utility customers over the course of a billing cycle. The credits are valued at the "same price per kilowatt hour" (kWh) that customers would otherwise be charged for electricity consumed. Net credits created in one billing period carry forward to offset customer-generators' subsequent electricity bills. At the end of every year that a customer-generator

[16] Section 2827(b)(4) defines an eligible customer-generator as:

> a residential customer, small commercial customer as defined in subdivision (h) of Section 331, or commercial, industrial, or agricultural customer of an electric utility, who uses a renewable electrical generation facility, or a combination of those facilities, with a total capacity of not more than one megawatt, that is located on the customer's owned, leased, or rented premises, and is interconnected and operates in parallel with the electrical grid, and is intended primarily to offset part or all of the customer's own electrical requirements.

There are also specialized provisions for the Department of Corrections and Rehabilitation and Armed Forces bases and facilities has been on the NEM tariff, the credits and charges accrued over the previous 12-month billing period are "trued-up."[17]

When first enacted, the NEM program had a cap on total participation by customers that was defined by statute as "0.1 percent of the utility's peak electricity demand forecast for 1996."[18] The Legislature also capped the capacity for each NEM-eligible facility at 10 kW. The Legislature enacted a significant program change with AB X1 29 (Kehoe), Stats. 2001, ch. 8, which increased the eligible system size from 10 kilowatt (kW) to 1 megawatt (MW). The Legislature has modified the statute several other times since 1995, often to increase the cap on NEM participation. AB 510 (Skinner), Stats. 2010, ch. 6, increased the cap on eligible capacity from 2.5% to 5% of aggregate customer peak demand for each utility.

On October 7, 2013, Governor Brown signed AB 327 into law. While AB 327 did not revise the existing cap of 5% of aggregate customer peak demand on eligible capacity, revisions to Section 2827 to clarify the methodology that the Commission must use to calculate the NEM cap were made. Additionally, AB 327 specifies that the trigger level marking the end of current NEM tariffs may not be lower than absolute MW levels specified in the statute for each of the large investor-owned utility (IOUs).[19]

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[17] A customer producing power in excess of its on-site load over the 12-month period may be eligible for "net surplus compensation" under certain conditions. The payment of net surplus compensation was authorized by AB 920 (Huffman), Stats. 2009, ch. 376, and implemented by the Commission in D.11-06-016.

[18] The statute included the exact figures for the 1996 system peak forecast for each utility.

[19] PG&E, SCE, and SDG&E.

The current NEM tariff provides multiple benefits to customer-generators, several of which are prescribed by statute. Under the existing NEM framework, customers receive credits at the full retail price per kWh exported as described in Section 2827(h). This is a higher credit rate than other programs, such as the fuel-cell NEM program (see Section 2827.10), that only provide compensation at the interconnected IOU's generation rate.[20] Section 2827(g) exempts NEM facilities from the standby charges that many other categories of self-generation must pay. In addition to these clear statutory benefits, the Commission determined in D.02-03-057 that Section 2827 was intended to exempt customer-generators from interconnection application fees, supplemental review fees, and costs for distribution upgrades other than the direct costs of facilities necessary to safely interconnect the generation facilities.

2.2.1. Virtual Net Metering

Virtual net metering (VNM) was originally authorized by the Commission in 2008 for multifamily affordable housing properties only in D.08-10-036, which established the MASH Program. VNM, as approved in that decision, allows electricity generated from a single solar energy system on a multifamily affordable housing property to be allocated as kWh credits to either common areas of the property or to individually metered tenant accounts, without requiring the system to be physically interconnected to each tenant's meter.

Based on experience with MASH projects, Energy Division staff recommended that VNM should be expanded to the general multi-tenant

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[20] The generation rate is the portion of per kWh charges that are directly associated with providing energy, excluding transmission and distribution costs and any nonbypassable charges.

market. The Commission authorized this expansion of VNM in D.11-07-031. Also in D.11-07-031, the Commission expanded VNM to allow its use for properties to include multiple service delivery points, but only for properties in the MASH program.

2.2.2. Net Energy Metering Aggregation

Net energy metering aggregation (NEMA) was authorized by SB 594 (Wolk), Stats. 2012, ch. 610, codified at Section 2827(h)(4). The Commission implemented NEMA via Resolution E-4610 in September 2013. NEMA allows an eligible customer-generator with multiple meters to

> elect to aggregate the electrical load of the meters located on the property where the renewable electrical generation facility is located and on all property adjacent or contiguous to the property on which the renewable electrical generation facility is located, if those properties are solely owned, leased, or rented by the eligible customer-generator.
> (Section 2827(h)(4)(A).)

2.2.3. This Proceeding

The origin of this proceeding is the direction in AB 327, codified in Section 2827.1, that the Commission develop a successor tariff or contract that will apply to facilities interconnecting in each IOU's service territory once the IOU's NEM cap has been reached, or July 1, 2017, whichever comes first. AB 327 further stipulates that customer-generators who interconnect under the existing NEM framework may continue on the existing NEM tariffs for a transition period to be determined by the Commission. In D.14-03-041, the Commission established a transition period of 20 years after the original year that each NEM facility interconnects. Consequently, the NEM successor tariff established by this decision will not apply to current NEM customers and other customers interconnecting prior to the attainment of the NEM caps or July 1, 2017, as applicable, until the end of their 20-year transition period.[21]

The current status of customer-sited generation under the existing NEM tariff is summarized in the following tables, prepared by Energy Division staff.[22]

Table 1: Total Interconnected NEM Capacity (Residential and Non-Residential) (As of September 30, 2015)

	PG&E	SCE	SDG&E	**Total**
MW Installed Capacity	1,665.8	1,128.2	446.7	**3,240.7**
Number of Installations	200,420	143,970	65,960	**410,350**

Table 2: Residential Interconnected NEM Capacity (As of September 30, 2015)

	PG&E	SCE	SDG&E	**Total Residential**	**Percent of Total Interconnected Capacity**
MW Installed Capacity	1,023.7	715.71	325.4	**2,064.81**	**64%**
Number of Installations	193,151	140,122	64,413	**397,686**	**97%**

[21] Such customers may also choose to change to the NEM successor tariff, but may not change back to their prior tariff once they have done so. D.14-03-041, Ordering Paragraph (OP) 2.

[22] The data in Table 1 are taken from Advice Letters (AL) filed by the IOUs reporting their progress towards their NEM transition trigger level as required by D. 14-03-041. (PG&E AL 4710-E; SCE AL 3291-E; SDG&E AL 2803-E.) The SDG&E data in Table 2 are taken from SDG&E's Daily NEM Program Limit Report, available at http://www.sdge.com/clean-energy/net-energy-metering/overview-nem-cap. The PG&E and SCE data in Table 2 are taken from the utilities' Q3 2015 reports on distributed generation interconnection data provided to the Commission's Energy Division in response to a standing data request and aggregated by Energy Division staff.

2.3. Regulatory Context

2.3.1. Residential Rate Design

Section 2827.1 is one part of a larger initiative on residential rate reform mandated by AB 327. In its recent decision on residential rate redesign, D.15-07-001, the Commission instituted a number of changes that are important both to residential rate design itself and to the process of developing the NEM successor tariff. Since the determinations made in D.15-07-001 are critical to development of the successor tariff, it is useful to review the most relevant outcomes of that decision before beginning the analysis for this one. As a result of D.15-07-001:

1. The four-tiered residential rates structured to charge customers a higher rate per kWh consumed as usage in a billing cycle exceeds certain thresholds is put on a "glide path" to be reduced to two tiers, with an ultimate ratio of 1:1.25 between them, by 2019.
2. A minimum bill for residential customers on the non-generation portion of their monthly electric bill in lieu of a fixed charge is adopted.[23]
3. Fixed charges, including demand charges, for residential customers may not be imposed at least until the process of tier flattening is finished, and a default time of use (TOU) rate is implemented for residential customers.[24]
4. Consideration of fixed charges for residential customers is to occur in a process beginning with a workshop in the Phase II of

[23] The minimum bill for California Alternate Rates for Energy (CARE) customers is $5; the minimum for non-CARE customers is $10.

[24] See Section 739.9(a):

> "Fixed charge" means any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based upon the volume of electricity consumed.

one IOU's general rate case (GRC)[25] that will gather information to: reflect appropriate costs; ensure a consistent methodology across utilities; and enable implementation after each IOU has shifted to default TOU rates for residential customers.[26]

5. Development of default TOU rates for residential customers is to begin with pilot programs that will begin in June 2016 and explore customer acceptance and engagement with a variety of different TOU rates. These pilots will also explore the load reductions achieved by the different TOU rates and the bill impact of the different TOU rates on various categories of customers. These pilots are to provide empirical support for IOU applications for a default TOU rate in 2018, with the goal of instituting default TOU rates in 2019.

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

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[25] This process has recently been initiated by the e-mail ruling in Application (A.) 14-06-014 Directing that Pacific Gas and Electric's Upcoming General Rate Case Phase 2 Proceeding should Include within its Scope a Workshop Process Examining Categories of Fixed Charges (November 6, 2015).

[26] *See* D.15-07-001 at 190-193.

2.3.2. Residential Time of Use Rates

D.15-07-001 orders the IOUs to file applications by January 1, 2018 for default TOU rates to take effect beginning in 2019.[27] The differentials between peak and off-peak rates will be determined by the Commission as it deliberates on the TOU proposals the IOUs will file. Information that can inform the timing of the peak periods will be considered in a recently proposed rulemaking on TOU issues.

The Commission is considering a new rulemaking that would establish one proceeding in which to gather and analyze data related to system load shapes and the implications of the load shapes for TOU rate periods for all of the large IOUs. The OIR does not envision that a final decision in the TOU rulemaking will set specific TOU rates. Instead, the proceeding is intended to provide direction to subsequent proceedings on the methodology to use when setting TOU rate periods, as well as the time periods to be used for TOU rates approved during the next few years.

2.3.3. Work Related to Distributed Energy Resources

Proceedings intensively examining the role of distributed energy resources (DER) are also ongoing. These proceedings include Distribution Resources Planning (DRP) (R.14-08-013) and Integration of Distributed Energy Resources (IDER) (R.14-10-003).

The DRP proceeding will potentially affect the analysis of the costs and benefits of a NEM successor tariff. As preliminarily scoped in the OIR, the DRP proceeding would examine the full range of distribution planning activities

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[27] D.15-07-001, OPs 9 – 11.

mandated by the Legislature in AB 327, specifically Section 8 of the bill, adding Section 769 to the Public Utilities Code.[28] In Section 769(b), the Legislature directs the IOUs to file distribution resources plans with the Commission by July 1, 2015.[29] The legislation enumerates five topics the plans must address:

1. evaluation of the locational benefits of distributed resources (§ 769(b)(1));
2. identification of tariffs, contracts, or other mechanisms to stimulate deployment of distributed resources (§ 769(b)(2));
3. proposed methods to coordinate existing programs, tariffs, and incentives to maximize the net benefits of distributed resources (§ 769(b)(3));
4. identification of any additional utility spending necessary to integrate cost-effective distributed resources (§ 769(b)(4)), and
5. identification of barriers to the deployment of distributed resources (§ 769(b)(5)).

Energy Division staff has proposed that the DRP proceeding would address

> 'optimal locations' for DER, the avoided costs of DER deployment, as well as the projected growth of DER throughout the IOU service territories.

(Energy Division Staff, "Distribution Resources Plan (DRP) Roadmap Straw Proposal" (Nov. 2, 2015)), available at http://www.cpuc.ca.gov/PUC/energy/drp/.)[30] The staff proposal for the DRP

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[28] Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (DRP OIR) (August 20, 2015).

[29] The plans, filed in the form of applications, are Application (A.) 15-07-002 through A.15-07-008.

[30] The staff straw proposal is also attached to the ALJ's Ruling Inviting Comments on Roadmap Staff Proposal (November 16, 2015).

further identifies the possible development of three analytic tools, all of which would be relevant to the consideration of costs and benefits to the electrical system and all customers with respect to the NEM successor tariff.[31]

In the IDER proceeding, R.14-10-003, the Commission adopted a definition of the integration of distributed energy resources (D.15-09-022, OP 3):

> A regulatory framework, developed by the Commission, to enable utility customers to effectively and efficiently choose from an array of distributed energy resources taking into consideration the impact and interaction of resources on the grid as a whole, on a customer's energy usage, and on the environment.

Based on that definition, the Commission also adopted the goal "to deploy distributed energy resources that provide optimal customer and grid benefits, while enabling California to reach its climate objectives." (OP 4).

While discussion continues regarding the coordination of the DRP and the IDER proceedings, in D.15-09-022 the Commission indicates that questions regarding the mechanisms by which customers may be compensated for the locational values and grid services that their distributed resources provide will be considered in the IDER proceeding. Thus, the determination of locational value (also referred to as locational net benefits) for distributed energy resources, required by § 769(b)(1), would occur in the DRP proceeding. Once locational values have been determined, D.15-09-022 states that the Commission will consider mechanisms to compensate owners of distributed resources for the locational values that they provide (addressing paragraphs 2 and 3 of § 769(b)) in the IDER proceeding.

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[31] The staff proposal describes these tools as: Integration Capacity Analysis; Locational Net Benefits Analysis; and DER Growth Scenarios.

2.4. Party Proposals

The ALJ's Proposal Ruling set out the requirements for parties' proposals. The *Staff Tariff Paper* and the *Staff Disadvantaged Communities Paper* provided methods and models for formulating and presenting proposals.

The two types of proposals will be presented separately here. Following the lead of the Staff Papers, the parties unanimously agreed that the consideration of alternatives for growth in disadvantaged communities would be most effective by proposing a programmatic approach, rather than trying to incorporate the proposed alternatives into the successor tariff itself.

A smaller number of parties also made proposals or comments on issues related to safety; consumer protection; and marketing, education and outreach. These proposals are summarized at the end of this section.

2.4.1. Successor Tariff or Contract

Twelve parties filed successor tariff proposals.[32] These proposals fell into four general categories:

1. Maintain full retail rate NEM in its current form, where renewable generation directly offsets onsite usage, and customers are provided compensation at their retail rate for exports to the grid.
2. Maintain full retail rate NEM, adding either a demand charge or an installed capacity charge.
3. Allow customers to use generation to serve onsite usage, and receive compensation for exports to the grid at less than full retail

[32] Although in the ALJ's initial Policy Ruling, parties were asked to comment on the relative advantages and disadvantages of a successor tariff versus a standard contract, in the end this issue was not important. All parties other than CARE proposed a successor tariff; CARE proposed a standard contract.

rate. Proposals also include either a demand charge or an installed capacity charge.

4. Institute a "value of renewables" tariff, by which customers purchase all energy consumed and are credited on their bills at the utility's "avoided cost" for all energy their systems generate.

2.4.2. Maintain Full Retail Rate NEM

Six parties presented five proposals in this category: CALSEIA; SEIA and Vote Solar (jointly); Sierra Club; TASC; and Federal Agencies.

2.4.2.1. CALSEIA

CALSEIA proposes to maintain full retail rate NEM for all customer classes going forward. It proposes that customers pay Public Purpose Program Charges (PPP) for electric charges offset by NEM credits after the market recovers from the loss of the Federal Investment Tax Credit (ITC).[33] CALSEIA proposes that the method for determining when the market has recovered from loss of the ITC be calculated as a 12-month period in which the number of MW of NEM interconnections exceed the number of MW interconnected in the calendar year 2016.

CALSEIA also proposes that systems larger than 1 MW be allowed to participate in the NEM successor tariff, and receive full retail rate credit, as long as they pay all interconnection application costs and all interconnection upgrade costs.

[33] The ITC has had a checkered history over the past decade. It was initially created by the federal Energy Policy Act of 2005, as a two-year 30% investment tax credit for both commercial and residential solar systems. It was extended twice. Currently the residential credit is 30% of the qualified solar expenditures made during the year. The residential credit is slated to expire at the end of 2016. It is currently codified at 26 U.S.C. § 25D(g) (2015).

CALSEIA recommends that both VNM and NEMA be maintained going forward, but that the VNM program should be expanded to allow locations with more than one service delivery point to be eligible for VNM, as is allowed under MASH VNM.

2.4.2.2. SEIA/Vote Solar

SEIA/Vote Solar jointly propose maintaining full retail rate NEM for all customer classes going forward. SEIA/Vote Solar also propose that systems larger than 1 MW be allowed to participate in the NEM successor tariff, and receive full retail rate credit, as long as they pay all interconnection application costs and all interconnection upgrade costs.

2.4.2.3. Sierra Club

Sierra Club proposes maintaining full retail rate NEM for all customer classes going forward, but would require all NEM customers to go on a TOU rate. Sierra Club states that the development of an appropriate TOU rate is necessary, but does not recommend a specific transition path to a TOU rate. It states that the 2019 transition to default TOU for all residential customers may be an appropriate time to require NEM customers to take a TOU rate.

Sierra Club also suggests that it may be reasonable to require NEM customers to pay nonbypassable charges because they fund important public purpose programs. Sierra Club proposes expanding VNM eligibility to all customers on a single distribution circuit or within a single census tract.

2.4.2.4. TASC

TASC proposes to maintain full retail rate NEM for all customer classes going forward. It proposes that customers pay PPP Charges for electric charges offset by NEM credits after a transition period, not specified in the proposal.

TASC also proposes that systems larger than 1 MW be allowed to participate in the NEM successor tariff, and receive full retail rate credit, as long as they pay all interconnection application costs and all interconnection upgrade costs.

TASC proposes that VNM and NEMA should be allowed to continue. TASC suggests that, sometime during 2016, the Commission consider expanding VNM to allow multiple service delivery points at a single property.

2.4.2.5. Federal Agencies

Federal Agencies propose maintaining full retail rate NEM. They also propose that systems larger than 1 MW not only be eligible for the NEM successor tariff, but should be exempt from interconnection fees, grid charges, standby charges and nonbypassable charges.

Federal Agencies do not support any fixed or standby charges, but urge that these charges should be phased in over a 10-15 year period if they are determined to be necessary. Federal Agencies propose that separate generation facility installations on a single premise, like a military base, should be allowed to be designed and treated as separate customer generators under NEM, regardless of whether the facilities are associated with a single customer account or single service delivery point.

Federal Agencies also recommend that customers taking direct access (DA) or bundled services should have equal eligibility for the NEM successor tariff. In order to ensure this, Federal Agencies suggest that the NEM successor tariff should state that DA customers are free to independently negotiate NEM compensation issues with their generation provider.

2.4.3. Maintain Full Retail Rate NEM With a Demand or Installed Capacity Charge

Two parties--NRDC and ORA-- propose successors of this type.

2.4.3.1. NRDC

NRDC proposes that full retail rate NEM be retained, but that customers be subject to a continuously variable demand charge. The demand charge would be based on the highest hour of average demand that is coincident with the TOU on-peak period in a given monthly billing cycle.

NRDC does not propose a specific value for the demand charge, though it states that a small variable demand charge is an appropriate starting point. It does propose that the demand charge be differentiated by demand tranche, with different charges for demand from 0-3 kW, from 3-6 kW and from 6 kW and above.

In addition to being subject to a demand charge, residential NEM customers would be required to subscribe to a seasonal TOU rate.

NRDC also proposes that residential customers be required to pay PPP charges based on consumption of grid imports of electricity, in a similar manner to others in the same customer class.[34]

2.4.3.2. ORA

ORA proposes that full retail rate NEM be retained. Additionally, an installed capacity fee (ICF) should be introduced for residential customers, to be based on the size of the installed system.

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[34] This summary represents the final form of NRDC's proposal, which evolved somewhat from its original form in NRDC's Proposal.

The proposed ICF would increase in steps, based on a series of installed capacity targets. In the first step, residential customers on the NEM successor tariff would pay $2/kW-month until installed capacity of their IOU's NEM customers reaches 6% of its non-aggregate peak demand. At that point, the ICF would increase to $5/kW-month until an IOU hits 7% of its non-aggregate peak demand, and then the ICF would increase to $10/kW-month. NEM successor tariff residential customers would remain at their initial ICF level for the first 10 years their systems are operating, and then transition to whichever ICF is in place for the IOU at the end of the 10-year period.

ORA states that its proposal is not a revenue neutral fee, and there would therefore be no commensurate reduction in other rate design elements. ORA states that each utility would credit the ICF revenues it receives directly to all residential customers through their rates.

ORA proposes that in order for systems larger than 1 MW to be eligible for the NEM successor tariff, they must pass the Rule 21 Fast Track process. These projects would be required to pay all interconnection study and system upgrade costs and to pay all nonbypassable charges. ORA recommends that VNM and NEMA be maintained, but that they be limited to systems sized 1 MW and smaller.

2.5. Customers Use Generation to Serve Onsite Usage, Receive Reduced Compensation for Exports, and Pay a Demand or Installed Capacity Charge

The three IOUs each make proposals of this type.

2.5.1. PG&E

PG&E proposes a successor tariff that would allow customers to serve their onsite energy needs directly, and would compensate customers' exports to the grid by an on-bill credit at the energy portion of each customer's generation rate.[35] PG&E estimates that this would be the equivalent of approximately $0.097/kWh for exported energy.

Residential and small commercial customers would be required to go on a rate with a maximum non-coincident demand charge of $3/kW-month, and a TOU rate schedule. Larger commercial, industrial, and agricultural customers are already served on rates with demand charges, so no new rate changes would be created for those customers. The demand charge would not be seasonally differentiated and would be based on the customer's highest metered demand during the month--a 60-minute interval for residential customers and a 15-minute interval for commercial customers. The rate would be designed to be revenue neutral; thus, the volumetric retail rate would be lower than it would have been without a demand charge for NEM successor tariff residential and small commercial customers. PG&E also proposes that customers on the NEM successor tariff pay all nonbypassable charges on energy they consume from the utility.

PG&E proposes transitioning from annual true-ups of NEM credits to monthly true-ups of NEM credits, with net surplus compensation (NSC) paid to customers after the monthly true-up at the same rate that is currently available.[36] Although PG&E supports increasing the size of eligible systems to more than 1 MW, it proposes capping the total eligible system size at 3 MW.

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[35] Customers' electric bills are made up of three components: a generation component, a transmission component, and a distribution component. Electric bills also include nonbypassable charges.

[36] See D.11-06-016.

Customers with systems sized 30 kW or smaller would pay a $100 interconnection fee to cover PG&E's cost to interconnect the system. Customers with systems sized larger than 30 kW would pay a $1,600 interconnection fee. Customers with systems sized larger than 500 kW would in addition pay for all distribution upgrade costs triggered by their system.

PG&E proposes that VNM would only continue to support installation of systems on low-income properties, and NEMA would only continue to support installation of systems on agricultural customers' properties.[37]

With regard to DA and Community Choice Aggregation (CCA) customers, PG&E recommends keeping the current NEM structure in place, but requiring customers to go on the rate structures that PG&E bundled customers are required to go on.

PG&E recommends that the Commission review and revise the NEM successor tariff rates and policies on a regular basis, beginning in 2019 or when NEM installations reach 7,800 MW (50% beyond the current NEM cap), whichever occurs first.

2.5.2. SCE

SCE proposes allowing customers to serve their onsite energy needs directly, and to compensate exports to the grid by an on-bill credit at the utility's levelized avoided costs plus a renewable energy credit (REC)[38] adder. The REC

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[37] PG&E also recommends that all customers be required to provide access to their gross system generation data, which would require some kind of additional communications technology to be adopted.

[38] Section 399.12(h) defines a REC, in relevant part, as:

> (h) (1) "Renewable energy credit" means a certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through

Footnote continued on next page

adder would be applicable if the utility were authorized to count the exported generation towards its renewables portfolio standard (RPS) obligation.[39]

SCE estimates the exported energy compensation would be equivalent to approximately $0.07/kWh for the utility avoided cost and approximately $0.01/kWh for the REC adder. If the compensation for exports exceeds a customer's bill in a month, the customer may carry credits over to future bills. The utility's avoided cost would be calculated on a two-year levelized cost basis. This rate would be offered to the customer for a 20-year period.

In addition, residential customers, as well as commercial and industrial customers who do not already pay a customer or demand charge, would pay a grid access charge based on the installed AC nameplate capacity of the system. This charge is intended to recover a portion of SCE's fixed transmission and distribution costs associated with serving the customer, and nonbypassable charges associated with the energy displaced by the customer's system. The grid access charge would be set at $3.00/kW-month. The grid access charge would be an overlay to the existing rate structure and would not impact the rates for a customer's otherwise applicable tariff.

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the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.

(2) "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

[39] The RPS is codified at Sections 399.11-399.32.

SCE recommends the Commission reassess the export compensation rate and the transmission and distribution portion of the grid access charge every three years, concurrent with the General Rate Case Phase II, via a Tier 3 advice letter. SCE recommends that the Commission reassess the nonbypassable charge portion of the grid access charge only when it changes.

SCE proposes that, in order to be eligible for the tariff, systems larger than 1 MW must pass the Rule 21 Fast Track process and pay all associated interconnection fees and system upgrade costs.

SCE proposes that all customers pay a $75 application fee to cover the costs of interconnecting their systems. All non-residential customers would pay all Rule 21 supplemental review fees, study costs, and upgrade costs triggered by the interconnection request.

SCE also proposes discontinuing VNM and NEMA, with the exception of MASH VNM, and requiring all existing VNM and NEMA customers to transition to whatever successor tariff is adopted.

2.5.3. SDG&E

SDG&E presents two successor tariff proposals: (1) a class differentiated unbundled rate option known as the Default Unbundled Rate Option; and (2) the Sun Credits Option for customers to be credited at a single rate for all energy their systems generate. It proposes to make both tariffs available to customers, and customers may select which tariff they would like to subscribe to. The default unbundled rate option (unbundled option) is described in this section; the Sun Credits option is set forth in the following section.

The unbundled option would consist of:

- a class-differentiated System Access Fee for the recovery of curb-to-meter infrastructure and customer services, as well as Public Purpose Program charges;
- a Grid Use Charge for the recovery of capacity-related distribution costs;
- a TOU rate for energy delivered to the customer; and
- a wholesale rate for energy exported by the customer (approximately $0.04/kWh).

The System Access Fee would be a flat monthly charge. The Grid Use Charge would be a non-coincident demand charge based on the customer's maximum hourly demand in a given billing cycle. SDG&E estimates that, for residential customers, the System Access Fee would be approximately $21/month and the Grid Use Charge would be approximately $9/kW-month.

2.6. "Value of Renewables" Tariff Using Avoided Cost

2.6.1. CAlifornians for Renewable Energy

CARE proposes that customers with facilities sized up to 3 MW would pay for all of their energy consumption from the utility and would be paid for the power they export to the grid through a power purchase agreement (PPA) at the utility's avoided cost, tiered by energy generator type and system size for each utility.

2.6.2. SDG&E

SDG&E's "Sun Credits" proposal would require customers to purchase energy from the utility to meet all of their energy needs and to export all of their generation to the grid.[40] They would be compensated for exported energy with a bill credit equivalent to the retail system average commodity rate. SDG&E proposes an initial flat compensation rate because it is of the opinion that its current TOU periods do not line up with the times in which generation capacity is most costly. SDG&E states that once its TOU periods are aligned with generation costs of service, it will propose to change its compensation rate to a TOU structure.

Under SDG&E's proposal, VNM and NEMA customers would be required to participate in the Sun Credits option.

In addition to its unbundled option and Sun Credits proposals, SDG&E also makes proposals with respect to other aspects of the NEM tariff and related programs.

SDG&E proposes eliminating the annual true up for both the unbundled option and the Sun Credits plan. Customers would then be compensated for any excess generation on a monthly basis.

SDG&E also proposes that all non-intermittent generators, of whatever size and under either tariff option, will be subject to standby charges.

SDG&E proposes that systems larger than 1 MW must pass Rule 21 Fast Track in order to be eligible for the NEM successor tariff. The system must be sized to be the smaller of either the average annual load or the maximum annual demand. Customers would have to pay all applicable interconnection fees and system upgrade costs.

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[40] This arrangement would require the customer to purchase and install a separate meter to track the generation exported to the grid.

With respect to interconnection fees, SDG&E proposes that projects sized at 30 kW and below pay a $280 interconnection fee to cover the costs of interconnecting the system. Systems sized above 30 kW would be required to pay a $280 interconnection fee, as well as the cost of any additional studies and system upgrades as necessary. SDG&E states that it would seek an adjustment to the interconnection fee in the future to reflect changes in interconnection application processing costs.

2.6.3. TURN

TURN proposes a value of distributed energy (VODE) tariff. Under this approach, customers purchase energy from the utility to meet all of their energy needs and export all of their generation to the grid. They would be compensated for their exports via a bill credit equivalent to the utility's avoided cost. The export compensation rate would be calculated based on a levelized 10-year forecast of avoided costs, and would be recalculated annually. The compensation rate would be provided on a time-differentiated basis to reflect changes in value by hour and season.

The VODE would be fixed for the first 10 years a customer is on the tariff. At the end of the 10-year period, the customer would transition to whatever the VODE compensation rate is at that time. Customers' bills would be trued up on an annual basis, and any excess generation at the end of the year would be zeroed out.

Customers would also receive a distributed generation adder (DGA) bill credit for exported generation in addition to the VODE credit. TURN states that the DGA would be needed in order to ensure sufficient adoption by customers to reach the "sustainable growth" mandate of the statute. TURN proposes that the Commission determine a minimum level of system installations that would be necessary to meet the sustainable growth requirement, and then set the DGA at a level that would ensure those adoption targets were reached.[41] The DGA would only be provided for the first 10 years a customer is on the NEM successor tariff; after that period, the customer would only receive the VODE bill credit.

TURN recommends that the DGA level be revisited periodically, beginning after 2000 MW of capacity have been installed under the new tariff. The cost of the DGA would be recovered from all ratepayers and would be treated as a public purpose program charge.

TURN proposes that systems larger than 1 MW should be eligible for the NEM successor tariff but that they should receive a different DGA credit because larger systems are less expensive to develop, per MW of capacity. TURN does not propose a specific level for the adjusted DGA.

TURN also proposes that VNM and NEMA be maintained and that those customers participate in the new tariff structure.

Under TURN's proposed structure, all customers would pay all associated interconnection costs.

2.7. Systems Larger Than 1 MW

2.7.1. Background

Current NEM rules cap the size of eligible projects at one MW. Systems larger than one MW are subject to a variety of charges that NEM eligibility would exempt them from, including full responsibility for interconnection costs, applicability of utility specific nonbypassable charges and standby charges.

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[41] Using the quantitative measures referred to in the Public Tool and party proposals, TURN proposes that the DGA be set at a level that ensures a Participant Cost Test result greater than 1 and a Ratepayer Impact Measure of not less than 0.9. TURN does not provide a quantitative example for such a calculation.

AB 327 requires that the NEM successor tariff include rules that allow systems larger than one MW to be eligible. Specifically, it states that the Commission shall:

> Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements.[42]

In an effort to identify a range of options for dealing with this requirement, the Commission asked parties to include proposals for how to apply this requirement to their NEM successor tariff filings.

2.7.2. Party Proposals

Thirteen parties included proposals for how to address the eligibility of projects greater than one MW as part of their broader NEM successor tariff proposals and one party (Foundation Windpower) outlined parameters for eligibility in their comments on the proposals. In their proposals, SCE, SDG&E and ORA would require systems that are larger than 1 MW be eligible for the NEM successor tariff as long as they pass Electric Rule 21's Fast Track screens.[43] PG&E proposes that systems sized up to 3 MW be eligible. CALSEIA, SEIA/Vote Solar, Sierra Club, and TASC's proposals would allow all systems larger than 1 MW to be eligible as long as they pay all interconnection study and

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[42] Section 2827.1(b)(5).

[43] Overview of PG&Es Rule 21 Fast Track Process:

http://www.pge.com/b2b/newgenerator/wholesale_dist_fasttrack.htmlhttp://www.pge.com/b2b/newgenerator/wholesale_dist_fasttrack.html.

upgrade costs. The Federal Agencies propose that systems larger than 1 MW pay for upgrade costs that are needed solely as a result of the interconnection of the system and that the utilities must complete their interconnection studies within 30 days. Foundation Windpower does not propose a specific set of requirements, instead focusing on claims that the use of Rule 21 Fast Track and system size caps is discriminatory.

2.7.3. Alternatives for Growth in Disadvantaged Communities

Energy Division staff kicked off the development of proposals for alternatives for growth in disadvantaged communities by presenting two example proposals in the *Staff Disadvantaged Communities Paper*. One is an expansion of virtual net metering to a neighborhood scale (Neighborhood VNM). Under the Neighborhood VNM proposal, credits from a customer-sited renewable DG system could be allocated to any residential customer located in the same census tract and utility service territory as the host customer.

The second proposal is dubbed Incentive Enhancement. Under the Incentive Enhancement proposal, single-family affordable solar housing (SASH) and MASH would receive additional funding to focus on installing solar photovoltaic (PV) systems for residential customers in disadvantaged communities.

2.7.3.1. CEJA

CEJA proposes an environmental justice net energy metering (EJ-NEM) tariff which would establish a bill credit for customers in disadvantaged communities based on the projected long-term average residential retail rate (CEJA estimates it to be between 25 and 30 cents/kWh). The EJ-NEM credit would be designed to fully recover the cost of a PV installation over a 20-year contract. This compensation rate would be independent of the individual customer's rate and would be set annually for projects installed in that year.

In conjunction with the EJ-NEM tariff, CEJA also proposes that the Commission create a loan loss reserve to address the issue of low or nonexistent credit among many residential customers in disadvantaged communities as well as a suite of additional alternatives. In response to the signing of AB 693, CEJA modified its proposal to narrow eligibility for EJ-NEM to residential customers living in single-family homes and multifamily buildings smaller than five units, in order to address market segments that are not eligible for the AB 693 program.

2.7.3.2. GRID Alternatives

GRID Alternatives proposes continuing full retail NEM for qualifying customers in disadvantaged communities as well as a suite of programs to increase growth of renewable DG adoption in disadvantaged communities. GRID originally proposed additional funding for both SASH and MASH. However, in response to the signing of AB 693, GRID Alternatives modified its proposal to support adopting the AB 693 program in place of extending MASH funding. In addition to a SASH extension, GRID Alternatives also proposes adopting a complementary program as long as it is designed to incentivize low-income participation. GRID cites the Joint Solar Parties Disadvantaged Communities VNM (DAC-VNEM), SCE's community/shared solar program or CleanCARE as potential complementary programs, but does not make a specific recommendation.

2.7.3.3. IREC

IREC proposes creating the "CleanCARE" program, under which CARE customers could authorize the use of CARE funds to purchase renewable generation from a third-party owned facility. Participating customers would move to standard, non-CARE rates and receive kWh bill credits (assuming that the current NEM structure is carried forward) that would be guaranteed to result in a total bill less than or equal to the amount it would otherwise have been under standard CARE rates. I REC proposes that CleanCARE begin as a 5MW pilot program and expand if successful.

In addition to CleanCARE, IREC supports adopting several complementary programs to create a suite of alternatives for disadvantaged communities. IREC specifically supports SEIA/Vote Solar's DAC-VNM proposal[44] and an incentive enhancement, which could include implementation of the AB 693 program.

2.7.3.4. PG&E

PG&E originally proposed creating the "SolarCARE" program under which CARE customers in disadvantaged communities would be eligible to receive 100% of their annual usage from a PV system located in their community. Participating customers would remain on CARE rates and their total bills would be unchanged. PG&E proposed that SolarCARE be funded either by non-CARE ratepayers or the Greenhouse Gas Reduction fund and would be capped at 28 MW for the first three years, with the option to expand the program after the pilot period. In response to the signing of AB 693, PG&E modified its proposal to support adopting the Multifamily Affordable Solar Roofs program as the sole alternative for disadvantaged communities.

[44] See Section 2.7.3.9, below.

2.7.3.5. SCE

SCE originally proposed a combination of several alternatives for disadvantaged communities, including enhanced incentives for low-income customers in both single and multifamily residences, expanding community solar, continuing to allow the virtual allocation of credits for all individually metered multifamily housing in disadvantaged communities regardless of income, and a marketing, education and outreach strategy targeted at residential customers in disadvantaged communities. In response to the signing of AB 693, SCE modified its proposal to adopt the Multifamily Affordable Solar Roofs program in place of its proposed enhanced incentives for multifamily residences. SCE maintains the other elements of its proposal, including an incentive enhancement for single family homes.

2.7.3.6. SDG&E

SDG&E proposes installing utility-owned PV systems on multifamily housing and public schools located in the top 20% of CalEnviroScreen designated disadvantaged communities in its territory through the "Multi-Family Solar Shares" and "Solar at Schools" programs. Under both programs, SDG&E would install, maintain and operate the system and pay the building owner or school a $5/kW monthly lease payment. The programs would be funded through public purpose program charges paid by all ratepayers, excluding residential customers and K-12 schools located in disadvantaged communities. SDG&E proposes a five year program period with a budget cap of $50 million and the option to request a program extension.

Under the Multi-Family Solar Share program, residential customers in multifamily buildings would be credited for generation produced by the on-site system at SDG&E's proposed Sun Credit rate. The building owner would receive allocation of generation for common areas not to exceed 5% of the total energy generated. Under the Solar at Schools program, low-income residential customers would be credited at SDG&E's proposed Sun Credit ratefor generation produced by a system installed on a public school located within the same census tract.

2.7.3.7. ORA

ORA originally proposed to expand funding for SASH if the recently approved third party ownership model proves to be successful. After the signing of AB 693, ORA modified its proposal to add adopting the AB 693 program as an alternative for residents of multifamily housing.

2.7.3.8. TURN

TURN originally proposed providing an upfront financial incentive for the installation of renewable DG to property owners of low-income housing in disadvantaged communities, using SASH/MASH eligibility criteria. In response to the signing of AB 693, TURN modified its proposal to support adopting the AB 693 program as a "significant portion" of the AB 327 directive. TURN proposes an upfront incentive program for single-family housing if the Commission decides that an additional alternative is necessary, the specifics of which should be decided in a subsequent phase of this proceeding.

2.7.3.9. SEIA/Vote Solar

SEIA and Vote Solar jointly propose that the Commission adopt both IREC's CleanCARE proposal and DAC-VNM. DAC-VNM is similar to Energy Division Staff's Neighborhood VNM proposal in that it would expand VNM so that customers and projects do not have to be co-located. There are several differences between the two proposals, summarized in this table:

	Staff Proposal	SEIA/Vote Solar Proposal
Location Requirements	Benefiting customers and system must be located in the same CalEnviroScreen designated census tract and same IOU service territory.	Benefiting customers and system can be located in any CalEnviroScreen designated census tract within the same IOU service territory.
System Sizing	System size limited to aggregate load of benefiting customers.	System size only limited to interconnection size cap.
On-Site Load	System must serve some on-site load.	Host customer only required to have parasitic load.
CARE Credit Multiplier	N/A	Credit multiplier for CARE customers that corrects for size of average CARE discount.

2.7.4. Safety, Consumer Protection, Customer Education

2.7.4.1. Safety

A number of parties propose that an approved equipment list should be part of the NEM successor, continuing the practice under the California Solar Initiative (CSI).[45] Depending on the equipment at issue, parties propose that the California Energy Commission (CEC) maintain an approved equipment list that customers, installers, and IOUs can consult, and that other equipment have safety certification from a nationally recognized testing laboratory (NRTL). Foundation Windpower and NRG object to these proposals, arguing that there are enough safeguards in place that the Commission does not need to add more, especially in an area where the technology is dynamic.

CMUA, SCE, and SDG&E make a number of proposals for safety standards, including requirements for projects larger than 1 MW; and for

[45] They include: CEJA, CMUA, Greenling, Joint Solar Parties, ORA, PG&E, SCE, SDG&E, SEIA/Vote Solar, and TASC.

continuation of safety requirements in the existing NEM program. SDG&E urges that the possibility of technology-specific requirements should be expressly considered. Joint Solar Parties question whether any separate or additional safety standards are necessary, and state that in any event, the Commission's ability to impose safety standards is limited.

2.7.4.2. Consumer Protection

Parties have a range of views about the nature and extent of consumer protection measures, if any, the Commission should impose as part of the NEM successor tariff.

2.7.4.2.1. Warranties

CEJA and Greenlining propose that warranties like those for equipment used in CSI-subsidized installations (10 years for all equipment, but 25 years for modules) should be required under the NEM successor. PG&E and NRG support a warranty requirement.

SDG&E believes that warranties are a matter for the customer and installer to deal with, though customers are entitled to clarity in the information they are given. Joint Solar Parties and TASC (separately) argue that a warranty requirement could discourage innovation in product offerings. IREC and ORA suggest that equipment warranties are sufficiently common in the solar market now that it would be unnecessary, and potentially create an administrative burden, to impose a separate warranty requirement.

2.7.4.2.2. Disclosures and Standardized Practices

A number of parties suggest that the Commission should develop standard terms and/or disclosures that must be provided to customers (especially residential customers) before they have a NEM-eligible generation facility installed on their premises.[46] The proposals vary in detail. Some focus on the terms of the contract itself (e.g., TURN, supported by CEJA and Greenlining, and NRG; see also CARE's proposal). Some focus on standards for business practices of market participants (e.g., SCE, PG&E). SDG&E proposes that the Commission develop a standard disclosure document that must be given to customers before they make any contractual commitment to a generation system provider.

2.7.5. Miscellaneous Proposals

Parties have made proposals on several related topics, including continuation of the GoSolar California web site[47]; creation of an independent consumer advocate for customer-generators[48]; more active cooperation between the Commission and other state agencies with responsibilities related to installation of residential renewable DG systems[49]; an option for the customer to require an inspection of the system[50]; and clearer standards regarding availability of data to customers.[51]

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[46] Variations on this idea are proposed by CARE, CEJA and Greenlining (jointly), CMUA, NRG, ORA, SCE, PG&E, SDG&E, and TURN.

[47] ORA and Joint Solar Parties are in this group.

[48] ORA.

[49] ORA, SDG&E, CMUA, and PG&E.

[50] ORA.

[51] TASC.

2.7.6. Evaluation of Proposals for Successor Tariff or Contract

2.7.6.1. Policy Questions and Their Setting

The basic policy questions for this proceeding are set by the criteria for the successor tariff delineated in Section 2827.1(b). The three most important are those in Section 2827.1(b)(1), (b)(3), and (b)(4), reproduced here for ease of reference.

> (b). . . The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section. In developing the standard contract or tariff, the commission shall do all of the following:
>
> (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in 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.
>
> (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.

2.7.6.2. Policy Setting

Parties agree that the directions to the Commission in Section 2827.1 do not exist in a policy vacuum, to be filled solely by the Commission's decision on the successor tariff itself. On the contrary, many important settled policies and emerging policy issues have a significant impact on the design and operation of the successor tariff.

These important policies include policies determined within the Commission, but outside the scope of this proceeding, such as the residential rate redesign efforts discussed throughout this decision. Some are determined by action by more than one state agency, such as the complementary work of the California Energy Commission and this Commission on Zero Net Energy building goals.[52]

Others are legislatively mandated, though implemented by the Commission. These include the changes recently made by SB 350 (De Leon), Stats. 2015, ch. 547, which enlarges and extends the procurement goals for the RPS program; requires the Commission to require regulated utilities to develop integrated resource planning processes, to be approved by the Commission; and expands the Commission's role in meeting the greenhouse gas (GHG) reduction goals of the state.

More directly relevant to this proceeding, the work on distributed resources planning in the DRP proceeding, and the complementary work in the IDER proceeding, while initiated by legislation, have become important elements in the Commission's own processes for understanding the value of DER and being able to plan accordingly.

Finally, there are policies of the federal government that can have significant impacts on the value or effectiveness of the NEM tariff. The principal policy discussed in this proceeding is the federal ITC, which has provided a tax benefit for installing renewable DG systems to both residential and

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[52] While zero net energy policies have been clearly enunciated, in this area as well, much remains to be learned before the policies can be implemented. See, e.g., the recent CEC request for proposals for "Research Roadmap for Getting to Zero Net Energy Buildings" (November 2015), as part of the Electric Program Investment Charge (EPIC) research agenda. Available at www.energy.ca.gov, using dropdown menu Funding/Requests for Proposals.

non-residential customers for over a decade, and which is scheduled to end for residential customers at the end of 2016.

But it is worth remembering that federal policy may have less direct effects as well, as shown by the example of the response of federal agencies to the innovative Property Assessed Clean Energy (PACE) programs[53] that began in Berkeley, California, in 2008 and spread across the country in short order. In 2010, the Federal Housing Finance Agency raised questions about the status of federally-guaranteed mortgages under a PACE regime, effectively stalling PACE programs.[54] Although more recent federal actions have softened the impact of federal disapproval, the PACE financing innovation has not had a chance to become a significant part of the residential solar market.[55]

2.8. The Public Tool

Developed by Energy Division staff with consultants, the Public Tool is intended to provide a vetted, neutral platform on which all party proposals may

[53] These programs allow homeowners to borrow money from a pool arranged by their local government, and to secure repayment via a lien for their property tax payments.

[54] See Federal Housing Finance Agency. *Statement on Certain Energy Retrofit Loan Programs.* July 6, 2010. http://www.fhfa.gov/Media/PublicAffairs/Pages/FHFA-Statement-on-Certain-Energy-Retrofit-Loan-Programs.aspx.

In 2013, the California Legislature attempted to mitigate the impact of the FHFA statement by enacting SB 96, Stats. 2013, ch. 356, that authorized the California Alternative Energy and Advanced Transportation Financing Authority to develop the PACE Loss Reserve Program.

[55] U.S. Department of Housing and Urban Development. *Guidance for Use of FHA Financing on Homes with Existing PACE Liens and Flexible Underwriting through Energy Department's Home Energy Score.* August 24, 2015. http://portal.hud.gov/hudportal/documents/huddoc?id=FTDO.pdf.

We take official notice of these federal agency statements pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedure.

be tested and compared on an "apples to apples" basis.[56] The Public Tool is <u>not</u> intended to generate "the answer" to any policy questions about the NEM successor tariff.

The Energy Division *Staff Tariff Paper* provided representative uses of the Public Tool and modeled how to use it. Parties were also allowed by the ALJ's Proposal Ruling to make changes to inputs and assumptions and "states of the world" in their use of the Public Tool, so long as those changes were properly documented.

Because of both limitations of the internal logic of the Public Tool, and uncertainty about the external conditions in the world in the future, the *Staff Tariff Paper* used two "bookend" scenarios: one in which customer-sited renewable DG is postulated to have a "high" value to all customers, and one in which customer-sited renewable DG is postulated to have a "low" value to all customers. Parties used these "bookends" to evaluate their proposals. Some parties also took advantage of the opportunity to create a third, customized scenario.[57]

The Public Tool uses the Standard Practice Manual (SPM) tests originally developed by the Commission in 1983, and revised a number of times since.[58] The tests described in the SPM are the Participant Cost Test, the Program Administrator Cost Test, the Ratepayer Impact Measure, the Total Resource Cost

[56] The development of the Public Tool is summarized in Section 1.1, above.

[57] These parties include CALSEIA, PG&E, SCE, SEIA/Vote Solar, Sierra Club, TASC, and TURN.

[58] See California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, (October 2001) at 1.

Test and the Societal Cost Test.[59] The definitions and uses of these tests are summarized in Appendix B to this decision.[60] As can be seen from parties' comments and proposals, the use of these tests in this proceeding is not without controversy. However, because parties used the Public Tool in presenting their proposals, we defer any major discussion about the value of the SPM tests in the abstract, and focus on how to evaluate the parties' proposals today. Examples of the results using the Public Tool are presented in Appendix C to this decision.[61]

2.9. "Continues to Grow Sustainably"

The primary direction to the Commission is to "ensure that the . . . tariff . . . ensures that customer-sited renewable distributed generation continues to grow

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59 The Standard Practice Manual can be accessed here: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

60 Both the DRP proceeding (R.14-08-013) and the IDER proceeding (R.14-10-003) include in their scopes a determination regarding cost-effectiveness methodologies for demand-side resources going forward. These determinations may impact the way demand-side resource programs, potentially including the NEM successor tariff, are evaluated in the future.

61 As explained in more detail in Appendix C, these tables were prepared by Energy Division staff for this decision, based on Public Tool runs submitted by the parties. Because the Public Tool is complex and time-consuming to run, only the most summary results are included for illustrative purposes. Details about the runs and issues related to the Public Tool may be found on the web site maintained by Energy Division staff at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.

A note on the presentation of the results is in order. Because of limits to the logic of the Public Tool, the model cannot change rates in midstream, as it were: it must use one rate structure to model throughout the time period covered by the model. After D.15-07-001 was issued, parties were therefore instructed to use three possible rate structures: the "two-tier" rate set by D.15-07-001; and two different, hypothetical TOU rates. For use as illustrations in this decision, only the model runs with the two-tier rates approved in D.15-07-001 are presented, because these are the only rates that staff and parties know are real and accurate.

sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities." (Section 2827.1(b)(1).)[62]

"Sustainable growth "can be understood in several ways. One, advanced by CALSEIA and TASC, is that growth must be robust enough to overcome actions that can reduce or inhibit growth, such as the looming end of the ITC for residential customers and reduction in the ITC for non-residential customers, and continue on a constantly growing course.[63] Another, advanced by SCE and PG&E, holds that "sustainably" must mean "without subsidy from other ratepayers," i.e., minimally intrusive on the economics of other customers.[64] The *Staff Tariff Paper* tries to steer a middle course, proposing that growing sustainably should be interpreted as "preserving and fostering sufficient market conditions to facilitate robust adoption of customer-sited renewable generation while minimizing potential cost impacts to non-participants over time."[65] Before turning to how to implement this understanding in practice, we review an objection to the way the Public Tool projects growth.

The Solar Parties in their comments on the successor tariff proposals claim that the "Low" solar price case available for use in the Public Tool substantially overestimates the decline in the price of installed solar systems, particularly for

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[62] Because all parties agree that the appropriate method to "include specific alternatives designed for growth among residential customers in disadvantaged communities" is through programmatic elements, rather than the successor tariff itself, proposals for alternatives designed for growth of DG among residential customers in disadvantaged communities are discussed separately in Sections 2.7.3 and 2.27.

[63] CALSEIA Proposal (Aug.3, 2015) at 5-7; TASC Proposal (Aug. 3, 2105) at 16-17.

[64] SCE Proposal (Aug. 3, 2015) at 11-17; PG&E Proposal (Aug. 3, 2015) at 35-37.

[65] *Staff Tariff Paper* at 1-4.

residential customers, over the next several years. As a result, the Solar Parties claim, the Public Tool can significantly overestimate the number of MW of adoptions of solar PV systems. Although this would obviously contribute to growth, the solar parties are concerned that it could lead to actions by the Commission to reduce the impact of the projected growth, such as reductions in the benefits offered to customers under the NEM successor tariff.

At the evidentiary hearing, CALSEIA introduced evidence about the structure of the solar installation industry in California, and the relationship of current prices to the prices projected under the Public Tool's "low" solar price case.[66] The proffered testimony provided useful information about how solar installations in California are contracted for by customers and carried out by providers of installation services. Neither the testimony nor the documentary evidence offered by the witnesses or cross-examining parties clearly established that there is something "wrong" with the Low solar price case, though it does stretch the current trends significantly. Nor did the testimony clearly establish that prices are likely to stop declining, though the question of how rapidly they will decline remains open.[67]

Since all participants in the hearing agreed that the Public Tool's "base case" of solar pricing was more than adequate to support reasonable growth, it is

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[66] Prepared Direct Testimony of Jose Luis Contreras and Mike Teresso on Behalf of the California Solar Energy Industries Association (Exhibit 1.) Although it was not the primary purpose of the testimony, the list of active solar installers in California provided in Appendix A was interesting and informative, showing the hundreds of solar installers active in California. Mr. Teresso noted that about 10 of these entities were active on a statewide basis.

[67] One example of uncertainty provided by witness Teresso is the inconsistent response of local governments to the mandate of AB 2188 (Muratsuchi), Stats. 2014, ch. 521, to create an expedited, streamlined permitting and inspection process for small residential rooftop solar energy systems.

not necessary to resolve the issue of whether the "low" case in the Public Tool is so inaccurate as to bias the Commission's consideration of its responsibility to ensure sustainable growth of customer-sited renewable DG.

Parties also offered a variety of perspectives on how to measure "growth." Some parties, including IREC and the joint solar parties, propose that year-to-year growth should be the measure. The IOUs oppose this concept, arguing that growth of customer-sited DG is affected by so many factors other than the NEM successor tariff itself that such tracking of growth would be misleading. In general, the IOUs oppose the adoption of any particular prescribed rate of growth or of adoption as a metric. TURN proposes that a simple metric of "net increase in customer installations" will capture the information needed and will not require complex quantitative methodologies.

In view of the external influences and uncertainties already discussed, it is difficult to know whether a particular metric for growth will be useful. The use of year-over-year comparisons ties the Commission's evaluation process too closely to a time period in which there may be significant, but transient, perturbations, such as the end of the ITC. Adopting no metric at all, however, runs the risk of not having a reason to pay attention to growth patterns.

On balance, a metric that looks 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 course should be considered. The Director of Energy Division should be authorized to require the IOUs to develop reporting and tracking tools that will allow such evaluation to be made, and to be made available in a publicly available form, whether through aggregation of data or other methods.

The impacts on growth of particular proposals, if relevant, will be discussed in the sections evaluating individual proposals.

2.10. "Total Benefits of the Standard Contract or Tariff to All Customers and the Electrical System are Approximately Equal to the Total Costs"

It is in the interpretation and application of this criterion that much of the controversy in this proceeding has occurred. Before turning to implementation of this legislative criterion, it is worthwhile to take a close look at its history.

In considering this requirement, it is important to remember that proposed new section 2827.1 was completely rewritten near the end of the legislative session that adopted AB 327.[68] Among the changes from the prior draft[69] was the elimination of all references to "nonparticipants" in the NEM successor tariff.

The proposed new Section 2827.1(b) in the August 21, 2013 draft is the last that included language about "nonparticipants." It read:

> At a minimum, in developing the standard contract or tariff, the commission shall do all of the following:
>
> (1) Establish rates, terms of service, and billing rules for eligible customer-generators.
>
> (2) Ensure that the standard contract or tariff made available to eligible customer-generators is based on the electrical system costs and benefits received by nonparticipating customers of the electrical corporation for the renewable electrical generation facility located on the customers' premises.

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[68] The major changes were made in Senate amendments dated September 3, 2013. The bill was passed in the Legislature on September 12, 2013.

[69] The prior draft was amended in the Senate August 21, 2013. It is the August 21 version that was removed and rewritten by the September 3 amendments.

(3) Preserve nonparticipant ratepayer indifference.

The September 3, 2013 draft was changed to read:

(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.

(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.

The prior subsection (1) on billing and other issues was renumbered as (2). The prior subsection (3) on nonparticipant ratepayer indifference was eliminated.

The language of the September 3, 2013 amendment carried through to the enacted statute, and is the language of Section 2827.1(b) today.

Therefore, when PG&E, SDG&E and ORA in their comments urge the Commission to evaluate proposals for the successor tariff in terms of their impact on nonparticipants (i.e., utility customers who are not using the NEM successor tariff), they are promoting a standard that is not consistent with the actual legislative requirement. The Legislature deliberately expanded the scope of statutory concern from "nonparticipating customers" to "all customers and the electrical system." Nonparticipating customers are one segment of "all customers," but they are clearly not the focus of the legislative direction to the Commission for designing the successor tariff.

The statute further identifies "total benefits" to be "approximately equal" to the "total costs" of the tariff. While this is a familiar reference to analysis of costs and benefits, it turns out to be more complex and uncertain than the familiar language would suggest.

The core problem in evaluating the proposals with respect to this criterion is that the "total costs" of the NEM successor are, at this moment in time, clearer, simpler to quantify, and easier to talk about than the "total benefits."

Costs are easily understood as the IOUs' costs that they recover through rates. Parties identify a disconnect between the contribution to IOUs' costs made by NEM customers and made by other customers, due to the netting arrangements of a NEM tariff. That is, when a NEM customer's consumption of electricity from the grid is netted against the customer's exports to the grid of energy not used on-site, the NEM customer has a smaller volume of electricity to pay for than the customer would have paid for in the absence of netting.[70] Because the full range of IOUs' costs are mostly recovered in volumetric charges from residential customers, the netting process results in a loss of volume on which the IOU could otherwise collect costs through the volumetric rate, and a consequent increase in rates to balance that out.

Among the SPM tests, this phenomenon is captured in the Ratepayer Impact Measure (RIM) Test, which focuses on whether a measure is likely to increase utility rates for nonparticipants.[71] A RIM value of 1 is intended to show that the costs and benefits (as reflected in utility rates) to the nonparticipants are roughly equal. Since nonparticipants are not the focus of concern in Section 2827.1(b), the RIM test cannot be the exclusive way to look at impacts. But since

[70] The electricity from the customer-generator's system that is consumed on-site is outside the purview of this discussion, since it never came from the interconnected IOU.

[71] See Appendix B.

nonparticipants are among the group of "all customers," the RIM test should not be ignored, either.[72]

The most interesting and instructive RIM test result emerging from the many runs of the Public Tool and iterations of proposals undertaken by parties in this proceeding is not to be found in any one of the results reported by any of the parties, or in the examples of the *Staff Tariff Report*. It is not a result that the test is intended to produce, but it is there nonetheless.

No party, using the inputs and assumptions in the Public Tool, could get the RIM value in the "Two rate tiers; High DG value"[73] case to equal 1.[74] Values ranged from a consistent 0.47 (as in the Staff Tariff paper) for the Solar Parties, Federal Agencies, NRDC, ORA (0.48) and Sierra Club; through values around 0.7 for the main IOU proposals.[75] SDG&E's "Sun Credit" proposal (essentially payment for all generation at the retail system average commodity rate) managed 0.9. TURN reverse-engineered its proposal to reach a RIM of 0.91, but still needs its Distributed Generation Adder (discussed in Section 2.11.1, below) to drive a reasonable number of customer adoptions of renewable DG systems.

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[72] The issue of whether, and if so how, the RIM test misses benefits to customers and the electric system is discussed below.

[73] *See Staff Tariff Paper* at 1-15 to 1-17. There is some question about the value of this case going forward. Since SB 350 adopted a new RPS target of 50% by 2030, one of the key assumptions of the "high DG value" case has changed. However, since the "high DG value" case is—other things being equal—likely to be more advantageous to non-participating customers than the bookend "low DG value" used in the Public Tool, it is reasonable to use it as the basis for discussing the meaning of RIM values.

[74] See Tables 1 and 3 in Appendix C.

[75] PG&E calculated RIM for its proposal at 0.66; SCE, at 0.68, and SDG&E for its "Unbundled" proposal at 0.71.

Using different inputs and assumptions for the value of DG, SEIA/Vote Solar just barely break the 1.0 barrier, as shown in Table 2 of Appendix C. TASC, which can safely be assumed to be equally motivated to find a high RIM value for continuing full retail rate NEM, as it proposes, is stuck at a RIM value of 0.83, even after making adjustments to Public Tool inputs and assumptions.

The point of this analysis is not to cast doubt on the RIM test, but to be clear about the place it has in considering proposals for a successor tariff. It is plain that the conventional way of looking at costs to nonparticipants is not fully functional for the NEM successor tariff.

These results show, somewhat surprisingly, that there is almost no version of a NEM successor tariff that does not have higher costs than benefits to nonparticipants, and to a significant degree. This could mean that there is no way to have a balanced NEM successor tariff. Or it could mean, as we conclude, that the large majority of costs of the NEM successor tariff are currently known and relatively easy to quantify, while the benefits to the electrical system and all customers are not fully known, and thus not able to be put in equivalent form on the other side of the equation with costs.

Since the Commission's first responsibility under Section 2827.1 is to see to the continued growth of customer-sited renewable DG, RIM results that suggest costs to customers not siting renewable DG on their premises also suggest that further investigation of benefits and costs is warranted.

Sierra Club, supported by CALSEIA, SEIA/Vote Solar, and TASC, proposes that we jump directly to a wide range of societal benefits to balance the perceived costs of the NEM successor tariff. Sierra Club includes Societal Cost of Carbon, Reliability and Land Use Benefits, Local Economic Benefits, Societal Cost of PM 10,[76] Societal Cost of NOx,[77] and Water Use as benefits that can be identified and quantified to provide balance to the equation of

Total Benefits ≈ Total Costs

Sierra Club's approach, while theoretically comprehensive, is premature. It relies on making some determinations of benefits and costs that currently are outside the scope of the Commission's expertise, and in some cases are clearly committed to other agencies, e.g. CARB's administration of the state's GHG cap-and-trade program. It also would require that the Societal Cost Test in the SPM be updated, if not substantially revised, to take account of many benefits that have recently increased in societal importance, such as GHG reduction benefits.

Such approaches are simply beyond the competence of this proceeding. They are also, perhaps more significantly, beyond its timeframe. Central to this problem is the disconnect in timing between the statutory requirement for the NEM successor tariff or contract to be in place not later than July 1, 2017, and the delivery of results from any other processes that might provide insight into the "benefits" side of the Section 2827.1(b)(4) equation.[78]

Even the planned delivery of results from Commission proceedings already under way exceed the tolerance of the NEM successor process timeframe. Looking first at the work related to improving the response of all

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[76] "PM 10" is shorthand for "particulate matter less than 10 microns in diameter."

[77] "NOx" is shorthand for "nitrogen oxides."

[78] The statute contemplates that the successor could be called into play earlier than July 2017. Section 2827.1(b) provides in part:

> A large electrical corporation shall offer the standard contract or tariff to an eligible customer-generator beginning July 1, 2017, or prior to that date if ordered to do so by the commission because it has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827.

customers to utility costs, three principal efforts are under way. The efforts to better align residential rates with both utility costs and grid needs are aiming for 2019 as the time they will come together in the form of default TOU rates for residential customers.[79] The work on defining standardized categories of costs on which fixed charges might be considered for residential customers is scheduled to begin at the end of March 2016, in PG&E's GRC Phase 2 proceeding, with no date for delivery of results yet established.

Looking next at the newer efforts to surface and identify values of DER that have previously not been available to the discussion of costs and benefits, two principal efforts have been undertaken by the Commission. The DRP and IDER proceedings will address at least five significant elements in the valuation of DER as set out in Section 769(b). The IDER proceeding is ultimately looking "to deploy distributed energy resources that provide optimal customer and grid benefits, while enabling California to reach its climate objectives," but does not yet have a timeframe for its next phase.

The state of these important processes is critical to the Commission's approach to the NEM successor tariff, as is more fully set forth below. At this time, none of the work discussed in this section is complete. Much of it has not been started, or is only in early stages of development by Energy Division staff. It is therefore not available for use in analyzing or designing the NEM successor.

This means both that the quantitative analysis in our decision about the successor is necessarily incomplete, and that a plan for reviewing the NEM successor tariff in 2019 is reasonable and realistic.

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[79] See D.15-07-001; R.12-06-013, Amended Scoping Memo schedule; as well as proposed TOU OIR, on the Commission's agenda for December 17, 2015.

2.11. Evaluation of Specific Proposals

2.11.1. "Value of Renewables" Tariffs/Contracts

CARE, SDG&E, and TURN all propose plans based on compensating the customer for all energy produced by the customer at a "value of renewables" or "avoided cost" rate, while having the customer pay the full retail rate for all energy consumed (whether self-generated or from the grid).[80] One potential advantage of such plans is that it separates compensation for customers' generation from the retail rate structure, allowing separate consideration of the pluses and minuses of each. Another potential advantage is that a customer's incentives for reducing electricity use, or using it at more grid-friendly times, are completely aligned with those of other customers, since the customer pays the full retail rate for all energy consumed.

The Solar Parties state that TURN's proposal rests on a framework that has never been adopted in California and violates customers' rights to consume energy generated on their premises with their private property. ORA believes TURN's proposal is administratively burdensome and largely untested. The Clean Coalition states that it supports any proposal that provides a time of delivery feed-in tariff for energy exported and an adder to meet the sustainable growth criteria.

TURN argues that SDG&E's Sun Credits option would not provide compensation at a sufficient level to ensure adequate adoption, and would mean customers would have to rely on a fluctuating rate and TOUs that SDG&E states are in the process of changing, which would subject customers to risk. ORA

[80] SDG&E and TURN also state that their proposals would require customers to buy a second meter, so that consumption and generation are separately metered.

supports SDG&E's attempt to provide NEM customers with a choice, in offering two different types of tariffs.

Solar Parties argue that requiring the customer to bear the cost of a second meter works at cross purposes with lowering the cost for customers to adopt on-site renewable generation. The Sierra Club argues that a structure like SDG&E's and TURN's would disempower customers. By divorcing energy use from production, customers would miss the opportunity to align production with grid needs. Foundation Windpower is concerned that SDG&E's and TURN's proposals are designed to address solar, and do not accurately capture the value provided by customer-sited wind systems.

Despite some theoretical potential, the disadvantages of the proposals are real and present, outweighing the theoretical benefits. TURN has named its proposal Value of Distributed Energy (VODE). But developing tools to understand the value of distributed energy, and to encourage the development and procurement of distributed energy of high value, is precisely the task of the DRP and IDER proceedings, as described above. While work on these issues is going on in those proceedings, it is neither administratively efficient nor fair to the parties participating in those tasks to jump the gun, as it were, and race off with a NEM successor tariff based on a valuation process special to this proceeding, but that the Commission is not using in its analysis of the value of distributed energy in general.

More specifically, this difficulty in valuation is demonstrated by the wide range of the proposals themselves. TURN concedes that, based on our current ability to value utilities' avoided costs, its proposed VODE will not provide sufficient incentive for the continued growth identified by Section 2827.1(b)(1). TURN proposes a "distributed generation adder," to be set so that it will encourage more customers to install DG systems, but TURN has no proposal for how to make such a calculation.

CARE, proposing a straightforward PPA at avoided cost for systems smaller than 3 MW, has no proposal for how to determine the "avoided cost" to use as the compensation amount. CARE also provides no analysis of the impact of its proposal on any of the criteria set out in Section 2827.1(b).

SDG&E's "Sun Credit," by contrast, proposes a specific rate of compensation to begin with for the customer's generation, its "retail system average commodity rate." SDG&E states that this rate would be $0.11/kWh. SDG&E states that this "retail system average commodity rate" would eventually transition to compensation based on a TOU structure, once its TOU periods are changed to align with generation costs of service. This is different from either the TURN or the CARE proposal in that SDG&E proposes using its "retail system average commodity rate," essentially a proxy rate for avoided cost to the utility, rather than a value calculated by the Commission as the avoided cost.

Without the analysis and information that is being developed in other proceedings, there is no sound way now to choose among these proposals.

2.11.2. NEM With Reduced Compensation, Added Charges

The three IOUs each propose a different version of the successor tariff. The proposals have in common maintaining full NEM for the customer's on-site usage,[81] but using a rate of compensation for exports to the grid that is less than

[81] Parties often refer to the treatment of a customer-generator's onsite usage as "full retail rate NEM." Though commonly used, and providing a clear image, this is not strictly speaking an accurate description of the situation. Under the existing NEM tariff, as well as logic, generation on the customer side of the meter that is consumed by the customer on-site is not subject to "net

Footnote continued on next page

the customer's full retail rate. All proposals also impose additional charges, whether denominated a demand charge, grid access charge, or system access fee, though no two of the proposals present the same rates or charges. All propose an interconnection fee, which will be discussed separately for each proposal.

2.11.3. PG&E

PG&E proposes continuing the existing full retail rate NEM for onsite use, but changing the compensation for exports to the grid to a rate that is the energy (per kWh) portion of the generation rate (approximately $0.097/kWh at current rates). PG&E would also add a demand charge of $3.00/kW-month for residential and small commercial customers, as well as requiring those customers to use an existing TOU rate. PG&E also proposes that the annual true up of energy credits be changed to a monthly true up, and proposes a periodic review of the tariff.

In its testimony, PG&E asserts that the calculation of demand charges for these customers is not different in principle from calculating demand charges for larger customers, who already pay such charges. In summarizing its proposal, PG&E's witness Daniel Pease states:

> . . . the distribution charges [on which the demand charges are based] are set based on the average cost of providing distribution service to the class (and not to a separately-defined NEM class) and do not utilize NEM-specific usage characteristics in their calculation. Similarly, marginal costs used in the derivation of the charges were those used for the class a whole and likewise do not reflect NEM-specific costs.[82]

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energy metering," since the electricity generated and consumed on-site never goes past the customer side of the meter into the distribution system. As noted above, the three "value of renewables" proposals do not follow this model, but all other proposals do.

[82] PG&E Opening Testimony at 2-11 (Hearing Exhibit (Ex.) 18).

PG&E's proposal for demand charges is expressly based on its costs for all residential (or small commercial) customers. PG&E's rationale for imposing such charges is that the demand charge would collect "a portion of the cost of distribution capacity."[83] Characterizing the costs to be recovered by its proposed demand charge as costs of distribution capacity does not, however, make the proposed demand charge not a demand charge.

350 Bay Area, City of San Diego, Foundation Windpower, MCE, Sierra Club, the Solar Parties, TURN, and Walmart and Sam's West oppose PG&E's proposal. The City of San Diego and NLine also oppose PG&E's proposal, stating that it would discourage renewable growth in California. TURN opposes PG&E's proposal because it would subject NEM successor tariff customers to three different rates for generation.

The Solar Parties and TURN oppose PG&E's proposal to institute a demand charge. They argue that it is complex and conceptually difficult to understand for residential customers, asserting that such customers spend only a few minutes a year focused on their utility bills. They also state that the Commission rejected a demand charge as too complex a proposal in R.12-06-013, the residential rates proceeding. In addition, the Solar Parties state that PG&E's proposed demand charge would overcharge NEM customers for their use of the distribution system.

The Sierra Club opposes PG&E's demand charge because it argues that the demand charge does not provide a price signal that correlates with grid needs,

[83] Ex. 18 at 2-2.

and is not aligned with cost causation because costs driven by peak demand should not be recovered by a non-coincident demand charge.

CSE states that demand charges should recover costs for all customers, not just DG customers, since demand charges recover costs related to the transmission and distribution system.

ORA does not oppose the proposal, but believes it would be a dramatic shift to go from current NEM to PG&E's proposed approach, and believes the proposal requires additional vetting because it essentially creates a new solar rate class.

The Solar Parties, TURN, 350 Bay Area, CSE, NLine, and CCOF oppose PG&E's proposal to transition to a monthly true up, stating that it will diminish the value of renewables, would increase customer confusion, and undermine customer adoption.[84]

The PG&E proposal also has the effect of imposing a de facto default TOU rate on residential NEM customers, by requiring a TOU rate immediately as part of the NEM successor tariff proposal. However, as the Commission recognized in D.15-07-001, the imposition of default TOU rates for residential customers requires an extensive process, that is only just beginning. Since the NEM successor tariff must be made available not later than July 1, 2017, and PG&E and SDG&E are likely to reach their caps on participation in the current NEM program before that date, PG&E's proposal with respect to TOU rates for residential NEM customers would have the effect of prematurely requiring

[84] The Solar Parties, Foundation Windpower and NLine believe there is no need to establish a periodic review of the NEM tariff, but if one is adopted, it must be balanced with the need for regulatory certainty.

residential NEM customers to go on mandatory TOU rates, using the TOU rates at the time of the customer's system interconnection, before the conclusion of the new TOU rulemaking and the results of the 2016 and 2017 pilots are available.

Moreover, since PG&E's proposal is expressed as the creation of a demand charge on a subset of residential customers—NEM residential customers—it is, in effect, an effort to revisit the Commission's determination in D.15-07-001 that fixed charges, including demand charges, should not be imposed on residential customers before default TOU rates have been established in 2019. That decision was made after extensive party participation and Commission deliberation. It should not be revised through the back door of a demand charge in the NEM successor tariff.

For these reasons, and those noted in Section 2.11.6, below, PG&E's successor tariff proposal should not be adopted.

2.11.3.1. Interconnection Fees

PG&E's proposal for interconnection fees should be adopted in part. PG&E's witness Daniel Gabbard identified a fee of $100 for interconnection of systems smaller than 30 kW. This is roughly in accord with SCE's costs, described below. PG&E, however, also proposed a fee of $1,600 for systems between 30 kW and 1 MW. Mr. Gabbard stated that the interconnection of systems larger than 30 kW is referred on an individual basis to PG&E engineers, thus accounting for the large difference in the proposed fee.

Because PG&E's fee proposal is not supported by actual cost data, the same amount should be charged for all interconnections of systems smaller than 1 MW under the NEM successor. The actual amount should be calculated based on the interconnection costs shown in PG&E's June 2015 advice letter (AL) 4660-E, filed in accordance with D.14-05-033 and Res. E-4610. In the calculation of the interconnection fee, PG&E may include only the following costs from its filing: NEM Processing and Administrative Costs, Distribution Engineering Costs, and Metering Installation/Inspection and Commissioning Costs. The interconnection fee amount should be included in PG&E's successor NEM tariff filed pursuant to the requirements of this decision If changes to the interconnection fee are required in the future, the process set out in Section 2.14.1.1, below, should be followed.

2.11.4. SCE

SCE proposes a hybrid structure for the successor tariff. Like PG&E, it continues the customer-generator's ability to use its generation on-site. SCE proposes to change the way exports to the grid are compensated, by substituting a fixed price that would be the sum of utility avoided cost and a "REC premium" for the netted-out compensation at full retail rates of the current NEM tariff. SCE would also add a $3/kW-month "grid access charge" to recover a portion of SCE's capacity or demand costs.[85]

350 Bay Area, CESA, City of San Diego, Clean Coalition, Foundation Windpower, Sierra Club, the Solar Parties, and Walmart and Sam's West oppose SCE's proposal.

The Solar Parties, Walmart and Sam's West, and the City of San Diego oppose SCE's proposal in general and state that SCE's proposal would greatly reduce the attractiveness of the NEM successor tariff to customers. The Solar Parties also raise concern specifically with the grid access charge, stating that SCE's charge is not consistent with system-wide costing principles, and is not

[85] SCE's Corrected Opening Testimony at 5 (Ex. 16).

tied to cost causation. The Solar Parties, TURN, Sierra Club, CESA and Clean Coalition also state that fixed charges discourage desired customer behavior, because a fixed charge provides no incentive to reduce energy use.

ORA does not oppose SCE's proposal, but believes it would be a dramatic shift to go from current NEM to SCE's proposed approach, and believes the proposal requires additional vetting because it essentially creates a new solar rate class.

SCE's proposal raises two principal issues, in addition to the overarching issue in all the utility proposals of whether the proposal demonstrates appropriate cost causation for the charges sought to be imposed. First, SCE's proposed compensation rate is based on the utility avoided cost used in the Public Tool model. However, it is not at all clear at this time that the Public Tool's avoided cost, or indeed any proposed utility avoided cost, captures both costs and potential benefits (e.g., locational benefits of DER) that are important.

Second, SCE's proposed grid access fee for residential and small commercial customers is a fixed charge that would be collected from residential NEM customers, though fixed charges may not be imposed on residential customers as a whole until the process set in motion by D.15-07-001 is completed. Although Section 2827.1(b)(7) allows a fixed charge for NEM successor tariff customers that is different from that for all residential customers, SCE does not present a compelling case for imposing the grid access fee now. Indeed, SCE does not fully support its grid access charge as a fixed charge. Rather, SCE's witness Behlihomji expresses a preference for using a demand charge, characterizing the proposed grid access charge as "a demand charge proxy."[86]

SCE seeks support for its view in language in D.15-08-005 that is supportive of the concept of a demand charge for NEM customers.[87] The rates of residential customers were not addressed in that decision. Its language on demand charges, which are now part of the rates of commercial and industrial customers, should not be stretched beyond their context in that decision.

Transmuting what SCE states is a demand charge into what it calls a fixed charge does not, however, solve the problem. It simply changes the description of a fixed charge to be imposed on residential customers (NEM successor tariff residential customers) that has not been developed in accordance with the process the Commission set out in D.15-07-001.

For these reasons, as well as those set out in Section 2.11.6, below, SCE's successor tariff proposal should not be adopted.

2.11.4.1. Interconnection Fees

SCE's proposal for interconnection fees--that all customers pay a $75 interconnection fee and all non-residential customers pay all Rule 21 supplemental review fees, study costs and upgrade costs—should, however, be adopted in part, as modified. SCE's witness Barsley testified that SCE had studied its actual costs for interconnection of NEM customers' systems and concluded that a fee of $75 would recover its costs. There is no dispute that this

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[86] Ex. 16 at 5.

[87] *See* D.15-08-005 at 33-34, Conclusion of Law 9.

fee is cost-based and reasonable, being based on the information provided in SCE's AL 3239-E, pursuant to Res. E-4610 and D.14-05-033.

SCE has not, however, provided cost data or support for its proposal to have non-residential customers pay additional study and upgrade costs. Therefore the same interconnection fee should be charged to all customers installing systems smaller than 1 MW, regardless of customer class. The interconnection fee amount should be calculated based on the interconnection costs shown in AL 3239-E. In the calculation of the interconnection fee, SCE may include only the following costs from its filing: NEM Processing and Administrative Costs, Distribution Engineering Costs, and Metering Installation/Inspection and Commissioning Costs. The interconnection fee amount should be included in SCE's successor NEM tariff filed pursuant to the requirements of this decision. If changes to the interconnection fee are required in the future, the process set out in Section 2.14.1.1, below, should be followed.

2.11.5. SDG&E

SDG&E makes two proposals. The "Sun Credit" rate is discussed in Section 2.10, above.

SDG&E's other proposal, described as a default unbundled rate for NEM successor tariff customers, includes a fixed charge of $21/month as a "system access fee" and a $9/kW-month demand charge as a "grid use charge." SDG&E's proposal also requires that NEM customers be on the TOU rates for their customer class. SDG&E, alone among the parties, further proposes standby charges for non-intermittent resources as a part of the successor tariff. Like the other utilities' proposals, it continues the customer-generator's ability to use its generation on-site. The proposed rate of compensation for a customer-generator's exports to the grid would be the wholesale energy rate, which SDG&E estimates at approximately $0.04/kWh.

350 Bay Area, City of San Diego, CSE, Foundation Windpower, Sierra Club, the Solar Parties, TURN, and Walmart and Sam's West oppose SDG&E's proposal. CSE states that using the wholesale energy rate to compensate customers does not capture the entire avoided cost to the utility of the customer's generation.

The Solar Parties take specific issue with the system access and grid use fees, stating that state law requires rates to be non-discriminatory, and it must be proven that the cost to serve NEM customers is different from other customers and therefore warrants a different structure. They also state that SDG&E's grid use charge would overcharge NEM customers for their use of the distribution system.

The Sierra Club opposes the grid use charge because it argues that as a demand charge, the grid use charge does not provide a price signal that correlates with grid needs; it is also not aligned with cost causation because costs driven by peak demand should not be recovered by a non-coincident demand charge. CSE states that demand charges should recover costs for all customers, not just DG customers, since they recover costs related to the transmission and distribution system.

ORA does not oppose SDG&E's proposal, but believes it would be a dramatic shift to go from current NEM to SDG&E's proposed approach, and believes the proposal requires additional vetting because it essentially creates a new solar rate class.

SDG&E's proposal for what are in effect mandatory TOU rates for NEM customers at the inception of the successor tariff is premature and suffers from the same difficulties as PG&E's TOU proposal, discussed in Section 2.11.3, above.

SDG&E's default unbundled rate proposes both fixed charges, demand charges, and compensation rates that are significantly harsher to the NEM successor tariff customer than those proposed by PG&E and SCE. The proposed fixed charge is seven times that proposed by SCE; the proposed demand charge is three times that proposed by PG&E. The proposed compensation rate is half or less than that proposed by the other two utilities. The fundamental change to the NEM tariff that these proposals would make is not adequately justified by SDG&E.

For these reasons, as well as the reasons set out in Section 2.11.6, below, SDG&E's proposed default unbundled rate for NEM customers should not be adopted.

2.11.5.1. Interconnection Fees

SDG&E's proposal for interconnection fees should be adopted in part, as modified. SDG&E's witness Ken Parks proposed an interconnection fee of $280 for systems 30 kW or less. For systems between 30 kW and 1 MW, SDG&E proposes a fee of $280, plus an indeterminate amount for additional studies or system upgrades, as determined by SDG&E.

These fees should be modified. Mark Fulmer, rebuttal witness for Joint Solar Parties, points out that a significant portion of the expenses included in SDG&E's calculation of the $280 fee comes from one-time expenses, particularly for upgrades to SDG&E's Distributed Interconnection Information System (DIIS). The Commission has previously noted that SDG&E has stated that its costs for the DIIS upgrade have been quickly paid for by efficiency improvements.

(D.14-11-001 at 7.) Mr. Fulmer calculated that, if the DIIS upgrade expense were removed, SDG&E's interconnection fee costs would be approximately $151.[88]

SDG&E has provided no justification for including an open-ended fee, at its discretion, for systems larger than 30 kW. Like PG&E and SCE, SDG&E's interconnection fee for all systems smaller than 1 MW should be calculated based on the interconnection costs shown in SDG&E's June 2015 AL 2791-E, filed in accordance with D.14-05-033 and Res. E-4610. In the calculation of the interconnection fee, SDG&E may include only the following costs from its filing: NEM Processing and Administrative Costs, Distribution Engineering Costs, and Metering Installation/Inspection and Commissioning Costs. The interconnection fee amount should be included in SDG&E's successor NEM tariff filed pursuant to the requirements of this decision. If changes to the interconnection fee are required in the future, the process set out in Section 2.14.1.1, below, should be followed.

2.11.6. IOU Proposals as a Whole

Although each IOU proposal has its own potential advantages and shortcomings, it is instructive to note the wide range of the specific charges and compensation rates in all the proposals. The differing methods of analysis and proposed charges strongly suggest that more work is indicated before any major shifts in the paradigm for the NEM successor tariff are implemented.

The proposals for change to the rate of compensation for NEM customers' exports to the grid vary by more than 100%. PG&E's proposal for compensation uses the energy (per kWh) portion of the generation rate (approximately

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[88] Joint Solar Parties Rebuttal Testimony at 52-53. (Exhibit 2.)

$0.097/kWh). SCE proposes the Public Tool's utility avoided cost of $0.07/kWh, plus a REC premium of $0.01/kWh. SDG&E makes two very different proposals for compensation in its two proposed NEM successors: the wholesale energy charge (approximately $0.04/kWh) for its default unbundled rate; and the system average commodity rate (approximately $0.11/kWh) for the "Sun Credit" rate.

This wide variation in proposed compensation is indicative of the incomplete state of analysis and information about the value of customer-sited renewal DG to the electrical system. This variety of proposals provides a strong argument for caution in making large changes to the NEM tariff structure prior to the completion of the work scheduled to be done as part of the DRP and IDER proceedings, discussed in Section 2.3.3, above.

The range of proposed fixed charges is even wider, from SCE's $3/kW-month grid access charge to SDG&E's $21/month system access fee. The methodological and cost basis for the fixed charges proposed by the IOUs for the NEM successor tariff are not simple, and far from consistent. Although it is possible for the Commission to impose fixed charges for NEM customers while not having them for other residential customers, the more prudent course would be to wait until the process for determining categories of fixed charges for residential customers, set in motion by D.15-07-001 and being carried forward in PG&E's Phase 2 proceeding, has borne fruit.

The economic idea of a demand charge, as PG&E and SCE note, is appealing. In principle, a demand charge can send customers an economic signal to adjust their energy usage based on system impacts. For large and sophisticated customers, that signal is in place in their current rates. As the Commission noted in D.15-07-001, however, and as echoed by a number of parties in this proceeding,[89] demand charges can be complex and hard for residential customers to understand. Since the vast majority of NEM customers are residential customers, it is reasonable to consider the NEM successor tariff in light of the needs of residential customers. From that perspective, the NEM successor tariff should not incorporate a demand charge, following the course on demand charges and other fixed charges set in D.15-07-001.

The IOU proposals also involve requiring NEM customers to be on existing TOU rate schedules immediately. For the reasons discussed above, this would be premature.

However, ultimately requiring participation in available TOU rates, in 2018 and later years, can be a way to align the incentives of customers on the NEM successor tariff with system needs, as well as provide valuable information to the Commission and stakeholders in advance of the Commission's implementation of default TOU rates for all residential customers. The IOUs' proposals are not deficient in principle, but their attempt to make TOU rates mandatory immediately for only some residential customers on the NEM successor tariff is premature.

2.12. NEM With Installed Capacity Fee or Demand Charge

2.12.1. ORA

ORA proposes continuing full retail rate NEM and adding an ICF. The ICF has two components: a small monthly fee based on the installed capacity of the customer's system; and an increase in the fee as the number of installed systems under the NEM successor tariff increases. The principal advantage of an

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[89] They include the Solar Parties and TURN.

ICF is that it is easy to understand. If the ICF is $2/kW per month, then a customer with a 5 kW system knows that she will pay $10 monthly for the ICF.[90]

350 Bay Area, CESA, Clean Coalition, CSE, Foundation Windpower, Sierra Club, the Solar Parties, TURN, and Walmart and Sam's West oppose this proposal.

TURN states that locking in capacity goals for the ICF transitions would not allow the Commission to respond to market changes in real time. Moreover, the proposal would subject customers to significant uncertainty regarding rate structure, given that the ICF is only static for 10 years.

The Solar Parties, Sierra Club, CESA, TURN, and the Clean Coalition oppose the ICF because they state that fixed charges discourage desired customer behavior, and the customer has no incentive to reduce energy use under a fixed charge. The Solar Parties further state that state law requires that rates be nondiscriminatory and it must be proven that the cost to serve NEM customers is different and therefore warrants a different structure. They also state that the ICF is not consistent with system-wide costing principles and is not tied to cost causation.

The City of San Diego and 350 Bay Area generally oppose a fixed charge, stating that it would discourage the adoption of renewable generation. The City of San Diego notes that, with some modifications to reduce the steep ICF charge increase and extend the ICF period beyond 10 years, ORA's proposal could be workable.

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[90] It is reasonable to consider a 5 kW system as representative of many residential customers. SCE in its testimony stated that the average NEM system size in its territory is 5.1 kW.

The feature of ORA's ICF proposal that the ICF increases with increasing installations also has the advantage of responding to changes in the actual relationship of customer-sited DG to the grid as a whole. However, ORA is not able to offer any technical or cost justification for the design of the increasing ICF steps. A one percent increase in NEM-eligible system penetration leads to a 150% increase in the ICF, to $5/kW-month. Another one percent increase in installations leads to a doubling of the ICF, to $10/kW-month. This may be a reasonable approach, but ORA acknowledges that it cannot demonstrate a quantitative basis for its approach at this time.

ORA also acknowledges that the progression to an ICF of $10/kW monthly is driven by its views of whether the ICF could grow so large that it would be a burden on the further growth of customer-sited renewable DG. ORA concludes that $10/kW-month, which is $50/month for an average size system now installed, would be the point at which the ICF should stop. It is not clear from ORA's presentation, however, what methodology would allow the Commission to estimate when an ICF would be, in that sense, "too high," or "high enough."[91]

This structure raises the important question, not resolved by ORA's proposal or testimony, of the cost causation of the proposed ICF. If the money from the ICF is being credited to ratepayers, the ICF should have an accessible connection to costs that are being borne by ratepayers. Other than a general sense that other ratepayers are paying more because NEM customers are paying

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[91] The Public Tool cannot model an ICF or other fixed charge that will change over time. The Public Tool must assume a single fixed charge amount for the entire forecast period in the model run. Therefore, the functionalities in the Public Tool do not provide a straightforward method for checking the cost justification for ORA's steps; ORA provides no alternate method.

less in their volumetric rates, ORA does not connect the ICF to a particular quantification that would support using this method to redress the balance.

Although the ICF has an appealing simplicity and directness, as proposed by ORA it is not yet ready for prime time. It is possible that after the information about locational benefits and optimal sourcing mechanisms being developed in the DRP and IDER proceedings becomes available, an ICF on a more sound quantitative footing could be developed. At this time, however, the Commission should not adopt ORA's proposed ICF.

2.12.2. NRDC

NRDC proposes that NEM customers pay what it describes as a "continuously varying demand charge," which would also be differentiated by the size of the demand.[92] NRDC does not present any quantitative example of how such a charge would be calculated, or what costs it would cover.

The City of San Diego, CSE, NLine, the Solar Parties, and Walmart and Sam's Club oppose NRDC's proposal.

The Solar Parties state that state law requires rates to be nondiscriminatory, and it must be proven that the cost to serve NEM customers is different and therefore warrants a different structure. The Sierra Club opposes the demand charge because it argues that the demand charge does not provide a price signal that correlates with grid needs, and is not aligned with cost causation because costs driven by peak demand should not be recovered by a non-coincident demand charge. CSE states that demand charges should recover costs for all customers, not just customer-sited DG customers, since they recover costs

[92] The three categories given by NRDC are 0-3 kW; 3-6 kW; and greater than 6 kW.

related to the transmission and distribution system. The City of San Diego and NLine oppose NRDC's proposal, stating that it would discourage renewable DG growth in California.

In D.15-07-001, the Commission concluded that proposals for demand charges that were much simpler than NRDC's proposal in this proceeding were very difficult for residential customers to understand. Because NRDC's proposal is even more complex than proposals considered in D.15-07-001, and in addition is not completely documented, it should not be adopted.

2.12.3. Maintain Current NEM

CALSEIA, Federal Agencies, SEIA/Vote Solar, the Sierra Club and TASC propose that the current NEM tariff be continued as the successor tariff. Some variations are proposed. CALSEIA and TASC propose that at some point in the future, NEM successor tariff customers would pay public purpose charges. Sierra Club suggests that, also at some point in the future, NEM successor tariff customers should be required to be on TOU rates.

CUE, ORA, PG&E, SCE, SDG&E, and TURN oppose maintaining current NEM.

PG&E asserts that current NEM should not be maintained because annual rate impacts resulting from the policy would be very high in the future. Both PG&E and ORA argue that the cost shift to non-participating customers under this policy would be too large to be tenable going forward. SDG&E also argues that maintaining current NEM fails to address the cost shift, and is inconsistent with the legislative intent of AB 327. TURN urges that the Commission should reject proposals that rely on retail rates for compensation because they are inconsistent with the requirement to base the tariff on the costs and benefits to customers and the system. CUE states that maintaining current NEM is inconsistent with the statutory requirements to ensure that the costs and benefits to customers and the grid are approximately equal because it results in costs to nonparticipating ratepayers.

The City of San Diego, Foundation Windpower, IREC, LGSEC, NEM-PAC, and Walmart and Sam's West support maintaining current NEM. 350 Bay Area supports maintaining current NEM but with a transition to TOU rates.

Maintaining current NEM has two obvious advantages. The first is familiarity. Customers, utilities, and installers of renewable DG systems are aware of the current NEM tariff and how it works. Installers have extensive experience with the existing tariff, which allows them to provide information to potential customers relatively easily.

The second advantage is demonstrated success in supporting the growth of customer-sited renewable DG. As shown in Section 2.2.3, above, there are currently more than 400,000 customer-sited installations, totaling more than 3,000 MW, on the existing NEM tariff in California. Assuming that the current full NEM tariff is maintained into the future, adoptions in the nine-year period 2017-2025 are projected to be over 11,000 MW, even in the "low DG value" case designed by Energy Division staff for use in the Public Tool.[93]

Continuing the current NEM structure is also consistent with the Commission's decision in D.15-07-001 not to impose fixed charges, including demand charges, on residential customers at this time. Since approximately 90% of NEM customers-generators are residential customers of the IOUs, it is reasonable to make choices about the NEM successor tariff that are in line with

[93] See Appendix C, Table 3, top three rows of table. Modeling to produce the table was undertaken by Energy Division staff based on scenarios submitted by the parties.

the choices the Commission has made about residential rate redesign as a larger matter.

The principal potential disadvantage of continuing the current full retail rate NEM tariff is economic. The IOUs lose revenue from NEM customers, particularly residential NEM customers, because those customers pay less to cover distribution costs through their volumetric rates. This revenue is recovered through increases in rates paid by all customers.[94]

Several parties, including the IOUs, ORA, and TURN, would like the successor tariff to take on the issue of a "cost shift" directly. However, as discussed throughout this decision, the Commission's analytic capacity and access to the relevant information that would allow a reasoned approach to this problem are still being developed. Given the choice between making a large change from existing NEM now and waiting for what promises to be much better tools for grounding that choice, we choose to base the successor tariff on current NEM, with changes that will better align the responsibilities of NEM customers with those of other customers in their class, looking toward the time when a more comprehensive reform of residential rates is completed and information from the DRP and IDER proceedings is available. (*See* Section 2.14 below.)

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[94] This circumstance is often referred to as a "cost shift" from NEM customers to other customers, who pay the increase in rates but without receiving any of the specific benefits, such as credit for exports, that accrue to NEM customers.

This proceeding has been one of the venues for the debate about whether, or to what extent, this is a net "cost" of the NEM tariff. As discussed in Section 2.3.3, above, the ongoing development of better analytic tools to address the question of costs and benefits of customer-sited renewable DG is a principal driver of our approach to developing the NEM successor tariff.

2.13. Evaluation of Proposals Related to Safety, Consumer Protection and Related Issues

Proposals to require the use of an approved equipment list are made by a number of parties.[95] Foundation Windpower and NRG object to these proposals, arguing that there are enough safeguards in place that the Commission does not need to add more, especially in an area where the technology is dynamic.

In a market that is directed in large measure to individual customers, it is reasonable to require minimum standards that will protect both consumers and the electric system from substandard equipment. Because of the history of using approved equipment lists, and NRTL-certified equipment under the Self-Generation Incentive Program (SGIP), this will not be a novel or burdensome requirement.

CEJA and Greenlining, as well as PG&E and NRG, support a requirement that warranties should be required under the NEM successor. SDG&E believes that warranties are a matter for the customer and installer to deal with, though customers are entitled to clarity in the information they are given. Joint Solar Parties and TASC (separately) argue that a warranty requirement could discourage innovation in product offerings. IREC and ORA suggest that equipment warranties are sufficiently common in the solar market now that it would be unnecessary, and potentially create an administrative burden, to impose a separate warranty requirement.

Because warranties have been required under both CSI and SGIP, it is reasonable and not burdensome to require a minimum 10-year warranty on

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[95] These include CEJA, CMUA, Greenlining, Joint Solar Parties, ORA, PG&E, SCE, SDG&E, SEIA/Vote Solar, and TASC.

equipment and its installation for the NEM successor tariff. A warranty will help to protect against defects and undue degradation of electrical generation output caused by faulty manufacture or installation, and to cover any expenses generated from repair and replacement of the system that are not otherwise covered by the manufacturer.

Parties express a range of views on whether additional safety requirements are needed for interconnection and other issues that are not strictly customer-sited equipment. CMUA, SCE, and SDG&E make a number of proposals for safety standards, including requirements for projects larger than 1 MW; and continuation of safety requirements in the existing NEM program. SDG&E urges that the possibility of technology-specific requirements should be expressly considered. Joint Solar Parties question whether any separate or additional safety standards are necessary, and that in any event the Commission's ability to impose safety standards on entities that are not regulated utilities is limited.

On these issues, the Commission's and IOUs' normal processes, particularly those related to interconnection, should suffice to maintain an appropriate level of safety of customer-sited installations. Interconnection and grid safety issues for systems larger than 1 MW are considered under that heading.

SDG&E's proposal that the Commission develop a standard disclosure document that must be given to customers before they make any contractual commitment to a generation system provider has merit, but requires further work on the details, including any required disclosures, how such disclosures will be presented, by whom (utility or installer), and how the presentation of such information packages will be verified. In the next phase of this proceeding, further work by Energy Division staff and the parties, including workshops or other forums, should be undertaken to develop a uniform information packet to be provided to customers interested in installing NEM-eligible systems. The process for approving the contents of such a packet should also be determined in the next phase of this proceeding.

The proposals parties have made on various other consumer protection and marketing and outreach topics include but are not limited to, creation of an independent consumer advocate for customer-generators; more active cooperation between the Commission and other state agencies with responsibilities related to installation of residential renewable DG systems; an option for the customer to require an inspection of the system; and clearer standards regarding availability of data to customers. These are most appropriately considered in the next phase of this proceeding.

Finally, no parties responded to the request to make proposals about measurement and evaluation of the NEM successor tariff. Measurement and evaluation are components of all other demand-side programs, and should be developed for the NEM successor tariff as well. This, too, is a topic for the next phase of this proceeding.

2.14. Successor Tariff: Realigned NEM

The basic NEM structure has succeeded in allowing more than 400,000 customers to provide renewable self-generation and renewable power to the grid. AB 327 has directed the Commission to review the balance of costs and benefits in creating a successor to the current NEM tariff.

This proceeding has largely focused on what is now known about the economic values and costs of the NEM tariff. In the DRPand IDER proceedings, the Commission has identified a number of important analytic tasks that should be completed in order to have a better understanding of the value and costs of distributed energy resources. The Commission has also set a path to significant revision of residential rates over the next few years, in D.15-07-001 and the ongoing work in the residential rates proceeding, as set forth in the Amended Scoping Memo in R.12-06-031.

The task of reviewing and revising the NEM tariff now, rather than when there is more complete information about the transformation of residential rates and the values of DER (and the mechanisms to implement those values), is driven by the statutory requirements to have the NEM successor tariff determined by the end of 2015, and in use by July 1, 2017 at the latest. The work on the successor tariff would greatly benefit from more information and improved analysis that the Commission has set in motion. Since that is not possible, given the timelines involved for the various proceedings, we must make the determinations about the NEM successor tariff at a transitional moment, rather than at a time when there is a wider and deeper array of information and analysis relevant to making that determination, on a more quantitatively informed basis.

We therefore choose to continue the basic NEM structure, while aligning the responsibilities of NEM customers more closely with those of other customers in their customer class. This approach will result in rates for customer-generators that are just and reasonable. (Section 2827.1(b)(7).)

We also set requirements that point the NEM successor tariff in the direction of consistency with future changes in the larger environment of rate design, such as default TOU rates for residential customers, slated to begin in 2019. Because the many initiatives that will have a bearing on the NEM successor tariff have timelines and deadlines that converge on 2019, we set

2019--after the institution of default TOU rates for residential customers and possible imposition of fixed charges for residential customers--as the time for a review of the NEM successor tariff.[96]

2.14.1. Aligning Customer Responsibilities

NEM customers are, first of all, customers of the IOUs. As the NEM successor tariff program continues in the future, it should move the economic contribution of NEM customers toward being more consistent with the contribution of other customers. In this NEM successor tariff, that is expressed in three forms: paying interconnection fees; paying nonbypassable charges for all energy consumed from the grid; and using the default residential TOU rate, or using another available TOU rate.

2.14.1.1. Interconnection

When they obtain particular services from the IOU unique to their status as customer-generators, such as interconnection services, NEM successor tariff customers should pay for them.[97] This modest one-time additional fee for NEM successor tariff customers with systems smaller than 1 MW should not have a noticeable impact on the economics of installing a DG system, but will allow the utility to recover the costs of providing the interconnection service from the customer benefitting from the interconnection.

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[96] PG&E and SCE propose that a schedule for periodic review of the NEM successor tariff should be set now. Since it is anticipated that a major review will occur in 2019, it is premature to set a schedule beyond that time.

[97] In this, as in other respects, the Commission recognizes that the prior NEM authorization, Section 2827, exempted NEM customers from such fees. The removal of that exemption allows the Commission to consider the matter afresh.

The evidence presented in the testimony and at the hearing demonstrates that the costs involved for interconnecting installations of less than 1 MW are not large.[98] There is, in addition, the information provided in the IOUs' advice letters in response to D.14-05-033 and Res. E-4610 to provide the basis for reasonable interconnection fees.

As part of their advice letters for the NEM successor, each IOU must also set a standardized interconnection fee under the NEM successor for customers installing systems less than 1 MW in size. The fee for each IOU must be based on the interconnection costs shown in each IOU's June 2015 advice letter, filed in accordance with D.14-05-033 and Res. E-4610. In the calculation of the interconnection fee, each IOU may include only the following costs from its filings: NEM Processing and Administrative Costs; Distribution Engineering Costs; and Metering Installation/Inspection and Commissioning Costs.

Because costs may change over time, each IOU must continue to report its interconnection costs in accordance with the directions in D.14-05-033 and Res. E-4610. Interconnection fees for the NEM successor tariff can only be changed by submitting a new fee calculation, based on the three cost areas set out above, in a Tier 2 advice letter served on the service list of this proceeding or any subsequent proceeding in which this NEM successor tariff (and/or any future successor tariff) is within the scope. The NEM tariff interconnection fees may not be changed by making a proposal to change them in the general rate case of any IOU.

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[98] Systems larger than 1 MW are discussed in Section 2.14.4, below.

No party has proposed any reason to change the existing requirement for the IOUs to process NEM interconnection requests for systems smaller than 1 MW within 30 days. This requirement is fair and reasonable and should be carried forward in the NEM successor tariff.

2.14.1.2. Nonbypassable Charges

Under the current NEM tariff, NEM customers pay the nonbypassable charges embedded in their volumetric rates.[99] They do so, however, only on the netted-out quantity of energy consumed from the grid, after subtracting any excess energy they supply to the grid.[100] The nonbypassable charges support important programs that are used by and benefit all ratepayers, including NEM customers. The majority of parties support changing the way NEM customers pay for nonbypassable charges (or at least the public purpose program portion of the charges) to align with the payment of such charges by customers not using the NEM successor tariff.[101] This is a reasonable change to the NEM tariff regime that is unlikely to have a significant impact on the economics of the

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[99] These charges are: transmission charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation Charge, and Department of Water Resources bond charge. CCA and direct access customers also pay the Power Charge Indifference Adjustment. (D.13-10-019 at 3 n.2.)

[100] See Section 2827(g), which provides in relevant part:

> The charges for all retail rate components for eligible customer-generators shall be based exclusively on the customer-generator's net kilowatthour consumption over a 12-month period, without regard to the eligible customer-generator's choice as to from whom it purchases electricity that is not self-generated.

[101] They include CALSEIA, ORA, PG&E, SCE, SDG&E, Sierra Club, TASC, and TURN. TASC and CALSEIA propose that NEM successor tariff customers pay public purpose charges at some point in the future. CALSEIA proposes that this be at a time after the negative impacts of the elimination of the residential ITC credit have dissipated; TASC proposes no particular timeframe.

customer-generator's system, but will recover costs that all customers pay in a fairer and more transparent way than under the current tariff.

Since a NEM customer's self-generated electricity does not come from the utility, the customer's self-generation is by definition not subject to nonbypassable charges. NEM customers should, however, pay nonbypassable charges on each kWh of electricity they consume from the grid in each metered interval.[102] This will eliminate the reduction in available kWh on which to pay the nonbypassable charges that now occurs when such charges are assessed only on the netted-out volume of electricity consumed from the grid, and mandate payment of nonbypassable charges on the full amount of electricity the NEM successor tariff customer receives from the grid, as it is with other customers.

2.14.1.3. Time-of-Use Rates

A new element in the successor tariff we adopt is the requirement that, as a condition of using the NEM successor tariff, all NEM customers interconnecting on or after January 1, 2018 must be on a TOU rate with no option to opt out.[103] Under the current NEM tariff, residential customers have had the choice to use the relevant TOU rate offered by their IOU, but have not been required to use it.[104]

In the residential rate redesign proceeding, the Commission has chosen default TOU rates as the principal incentive for residential customers to adjust their electricity use to minimize impacts on the electric grid at times of high

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[102] For residential customers, the metered interval is one hour.

[103] D.15-07-001 anticipates that default TOU rates will be in place in 2019.

[104] Most classes of non-residential customers of the large IOUs are required to be on a TOU rate, with exceptions for some classes such as streetlight customers.

demand. In order to maximize the value of the TOU rates in improving customers' responsiveness to demands on the grid,[105] the incentives for NEM successor tariff customers should be aligned with those of other customers in their class. Maintaining NEM successor tariff customers on their default TOU rate, or another available TOU rate, will accomplish this alignment efficiently and in a way that is easy for the customer to understand.

Because of the importance of TOU rates to the Commission's overall approach to residential rate reform and the incentives that TOU rates can provide for NEM successor tariff customers, it is important that use of a TOU rate (whether the default residential rate or another available TOU rate) be required of all customers who would like to use the NEM successor tariff. Because taking service on the NEM successor tariff is itself voluntary (i.e., no customer is required to use the NEM successor tariff), conditioning the customer's access to the NEM successor tariff on use of a TOU rate is not inconsistent with any of the requirements of Section 745.[106]

As a result, starting in 2018, residential customers using the NEM successor tariff will be required to use their utility's existing residential TOU rate

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[105] The Sierra Club provides some examples, including, "load-shifting from peak hours. . .[and] preferred . . . system design (such as west-facing solar) and . . . markets for new technology (like home battery storage or programmed appliances and thermostats)." (Comments on Proposals for Net Metering Successor Tariff, at 11-12.)

[106] Conditioning access to the NEM successor tariff on a customer being on an available TOU rate is not intended to alter any customer's rights under Section 745 to affirmatively consent to a TOU rate, or opt out of a TOU rate, or exercise any other option with respect to TOU rates that the Commission determines is appropriate in interpreting and implementing Section 745.

The condition that a residential customer must use an available TOU rate applies only if the customer intends to become a customer-generator and use the NEM successor tariff.

schedule or participate in a TOU pilot program. Requiring residential customers on the NEM successor tariff to use existing TOU rates or pilot TOU rates starting in 2018 represents an opportunity to more fully engage both customer-generators and third party service providers in the process of designing the TOU pilots and the design of default TOU rates in 2019. Although a requirement for residential NEM successor tariff customers to participate in the TOU pilots may not be appropriate, participation in the TOU pilots mandated by D.15-07-001 would be useful to NEM successor tariff customers, the IOUs, and the Commission.[107]

Residential customers using the NEM successor tariff whose systems are interconnected at any time during 2018, and at any time during 2019 that is prior to the institution of default residential TOU rates, should be encouraged participate in any TOU pilots that are designed to include NEM successor tariff customers.[108] After default residential TOU rates are instituted, a NEM successor tariff customer who participates in a TOU pilot would need to be on the default TOU rate, or another available TOU rate for which the customer is eligible, as a condition of continuing to use the NEM successor tariff, just as NEM successor tariff customers who do not participate in a TOU pilot would have to do.

2.14.2. Standby Charges

NEM customers under the current tariff are exempt from standby charges by statute. (Section 2827(g).) This exemption is not continued by Section 2827.1, but only SDG&E proposes a separate standby charge as part of the NEM

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107 See D.15-07-001, Sections 6.6, 12.2, 12.6 (schedule), and Finding of Fact 151.

108 The process for designing the TOU pilots is set by D.15-07-001. Nothing in this decision is intended to alter the requirements of D.15-07-001 or change the process of developing and running the TOU pilots.

successor tariff.[109] The parties' general lack of interest in imposing standby charges reflects the fact that standby charges have historically been charged to self-generating customers using non-intermittent resources. The self-generator can therefore predict its production with a high degree of accuracy and consistency. For the majority of NEM customer-generators on the successor tariff, who have systems that use intermittent renewable resources, the standby charge could function more like a demand charge, having potentially significant economic impact on the customer, depending on the amount of the charge and how it is set. The standby charge would also mirror the difficulty for the typical NEM residential customer of understanding a demand-like charge. There is no reason to impose such a charge in the NEM successor tariff.

2.14.3. Annual True-Up Period

Section 2827(h) mandates an "annualized net metering calculation." This mandate has been eliminated in Section 2827.1, which provides more permissively in Section 2827.1(b)(2) that the Commission must "establish terms of service and billing rules for eligible customer-generators" under the successor tariff.

The annual true-up should be continued in the NEM successor tariff. It preserves the value of net metering for all customers, but is particularly important for customers that have large seasonal variations in their electricity usage, such as agricultural operations and schools. Requiring true-ups on a monthly basis would cause significant losses for those customers, who rely on the annual cycle to even out the economic impact of their highly variable usage.

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[109] PG&E and SCE propose recovering the same charges, but through a demand or grid access charge.

Even customers without such sharp variations in their usage would stand to lose value under a monthly true-up, since some seasonal variation is present in all customers' usage patterns.[110] No compelling reason has been presented by the IOUs to change this intuitively sensible feature of the existing NEM tariff, and we decline to change to monthly true-ups in the NEM successor tariff.

2.14.4. Systems Larger than 1 MW

Section 2871.1(b)(5) has no limitation on the size of generation facility that can be eligible for the NEM successor tariff. In view of this open-ended authorization, it is reasonable to allow systems of any size to participate, so long as they meet the statutory requirement of having "no significant impact on the distribution grid." This can be accomplished by requiring that systems over 1 MW pay all interconnection costs under Rule 21, which will both cover the IOUs' costs and ensure that the projects themselves will meet the statutory requirement.

All rules and charges of the customer's underlying rate schedule continue to apply to a system larger than 1 MW that meets the requirements for participation in the NEM successor tariff. The special case of Armed Forces bases and facilities with generation facilities larger than 1 MW, which have special rules under Senate Bill 83, Stats. 2015, ch. 24, is discussed below.

2.14.4.1. Customer Generators Eligible Under SB 83

SB 83 altered the definition of "eligible customer- generator" to include a category of customer-generator that is a "United States Armed Forces base or

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[110] The net surplus compensation program, mandated by Section 2827(h)(3) and implemented in D.11-06-016, is also based on a 12-month true-up period.

facility," which is "an establishment under the jurisdiction of the United States Army, Navy, Air Force, Marine Corps, or Coast Guard."
(Section 2827(b)(4)(C)(i).) The Armed Forces base or facility must meet certain additional requirements, including having a renewable electric generating facility that is the lesser of 12 MW or one MW greater than the minimum load of the base or facility and excluding generation facilities for privatized military housing under certain circumstances. (Section 2827(b)(4)(C)(ii).) An Armed Forces base or facility that is an eligible customer-generator may not, however, receive any compensation for exported generation. (Section 2827(b)(4)(C)(iii).) A special tariff for customer-generators in the Armed Forces base or facility category must be made available by each IOU.

Because Section 2827.1(a) incorporates the definitions of "eligible customer-generator" from Section 2827, Armed Forces bases or facilities under the SB 83 definition are customer-generators for purposes of service under both the existing NEM tariff (as adjusted to incorporate the special characteristics of the category of Armed Forces bases or facilities) and the NEM successor tariff. An Armed Forces base or facility, if it is taking service under the existing NEM tariff, will be covered by D.14-03-041, the Commission's NEM transition decision. The Armed Forces base or facility will be able to use the 20-year transition period, as well as the opportunity to switch to the NEM successor tariff.

Under either the existing NEM tariff or the NEM successor tariff, the requirements of SB 83 will apply. Thus, although the NEM successor tariff does not limit the size of a generation facility so long as the customer meets the requirements set out in Section 2.14.4 above, an Armed Forces base or facility is, by virtue of its definition as an eligible customer-generator, limited in size to the lesser of 12 megawatts or one megawatt greater than the minimum load of the base or facility over the prior 36 months.

An Armed Forces base or facility is also unable to receive compensation for exported generation under the NEM successor tariff.

Each IOU must include in its NEM successor tariff all necessary provisions to take account of the particular circumstances of Armed Forces bases or facilities, as defined in SB 83.

2.14.5. Virtual Net Metering

The VNM tariff should be continued as a supplement under the NEM successor tariff. The VNM tariff allows multi-meter property owners to allocate bill credits generated from the renewable generation system to multiple service accounts associated with the property. VNM systems should be subject to the same requirements regarding nonbypasssable charges and interconnection costs as systems under the standard successor tariff. As all parties agree, the compensation structure for customers under the VNM tariff should be the same as that of the NEM successor tariff. The IOUs have not shown that the current VNM tariff is administratively burdensome or otherwise creates problem for the IOUs' administration of the tariff.

The Commission also adopts the CALSEIA proposal that the VNM tariff should be expanded to allow multiple service delivery points at a single site under the tariff. This has been allowed under the MASH VNM tariff since the adoption of D.11-07-031, and has been used successfully by participants, without administrative problems.

2.14.6. Net Energy Metering Aggregation

The NEMA tariff should also be continued as a supplement under the NEM successor tariff.[111] NEMA systems should be subject to the same requirements regarding nonbypassable charges and interconnection costs as systems under the standard successor tariff. Many agricultural customers have begun to use the NEMA tariff, which was implemented only two years ago in Res. E-4610. It is important to maintain continuity for NEMA, to allow additional customers, especially but not exclusively agricultural customers, to take advantage of NEMA to install renewable DG for their facilities. NEMA customers, like customers using the VNM tariff, are compensated the same way as all NEM customers; only the aggregation feature is different.

2.14.7. Direct Access Customers and Customers of Community Choice Aggregation

All the elements of the current treatment of DA and CCA customers should be maintained under the NEM successor tariff. These customers will be able to use the NEM successor tariff on the same terms as IOU customers. As is currently the case, the relevant IOU will credit the customer for the non-generation portion of the bill; the customer's electric service provider or CCA will credit the customer for the generation portion of the bill.

2.15. Duration of Service Under NEM Successor Tariff

The Commission recently decided, in D14-03-041 (implementing the requirements of Section 2827.1(b)(6)), that 20 years from the customer's

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[111] The original authorization and structure for aggregating multiple meters on one premises are set out in Section 2827(h)(4).

interconnection under the existing NEM tariff was a reasonable period over which a customer taking service under the existing NEM tariff should be eligible to continue taking service under that tariff. This decision should be applied to customers under the NEM successor tariff as well, to allow customers to have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG systems. Customers who elect to make a one-time switch from the current NEM tariff to the successor tariff, as allowed by D.14-03-041, OP 2, may continue to take service under the successor tariff for 20 years from the date of their original NEM interconnection; customers may not restart the 20-year period by switching to the successor tariff.

This duration of service applies only to service under the NEM successor tariff, not to any other aspect of the customer's bill, for example, a minimum bill. To avoid any misunderstanding, we reiterate our observation in D.15-07-001 that customers do not have any entitlement to the continuation of any particular underlying rate design, or particular rates. The 20-year period we designate applies only to a customer-generator's ability to continue service under the NEM successor tariff established by this decision.[112]

2.16. Safety and Consumer Protection

The IOUs should verify, as part of any interconnection request, that all major solar system components[113] are on the verified equipment list maintained

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[112] In view of our determination that a full consideration of alternatives for growth of renewable DG among residential customers in disadvantaged communities should be deferred to the next phase of this proceeding, we also defer deciding whether the 20-year period for service under the NEM successor tariff should be applied to customers taking advantage of any of the alternatives for disadvantaged communities that are ultimately adopted.

[113] These components include PV panels and other generation equipment, inverters, and meters.

by the CEC. Other equipment, as determined by the utility, should be verified as having safety certification from a NRTL. The interconnection request should also verify that a warranty of at least 10 years has been provided on all equipment and its installation.

2.17. Evaluation of Alternatives for Disadvantaged Communities

2.17.1. AB 327 Requirements

Following the suggestion in the *Staff Disadvantaged Communities Paper*, all parties agree that the plan for alternatives for growth in disadvantaged communities should not be embodied in the NEM successor tariff itself. The parties similarly agree that the criteria set out in Section 2827.1 for designing the successor tariff should not be applied to the design of the programs for growth of customer-sited renewable DG among residential customers in disadvantaged communities.[114]

The approach of the parties and Energy Division staff is sound. Since the Legislature determined that there is now a need for additional attention to alternatives for disadvantaged communities, it is reasonable to conclude that the incentives provided by the existing NEM tariff, including compensation at the full retail rate for exported energy and exemption from all charges imposed on other residential customers, was not sufficient to encourage growth. A revised NEM successor tariff, therefore, would be equally unlikely to encourage growth; the method for alternatives for growth must be found outside the successor tariff itself. That being the case, the statutory criteria for the successor tariff simply

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[114] For ease of reading and to avoid repetition, this goal will be referred to as "alternatives for disadvantaged communities."

have no application to the design of the alternatives for disadvantaged communities.[115]

2.17.2. Characterizing "Disadvantaged Community"

Section 2827.1 does not provide a definition of "disadvantaged community." The Commission does not, however, need to create a definition from scratch. In Health and Safety (H&S) Code Section 39711, the Legislature created a process for identifying disadvantaged communities for purposes of investment of funds from the Greenhouse Gas Reduction Fund.

The California Environmental Protection Agency (CalEPA) has implemented the legislative instruction by using a screening tool created in partnership with the Office of Environmental Health Hazard Assessment (OEHHA), called CalEnviroScreen; the current version of CalEnviroScreen is denominated CalEnviroScreen 2.0.[116] CalEPA and the California Air Resources Board (CARB) have used CalEnviroScreen to fulfill the legislative requirement of identifying disadvantaged communities for purposes of distribution of certain funds from the Greenhouse Gas Reduction Fund. The agencies have concluded that a "disadvantaged community" is a community that appears among the top 25% of census tracts identified by CalEnviroScreen 2.0 statewide.[117]

The *Staff Disadvantaged Communities Paper* recommends the use of this tool and the CalEPA/CARB result for characterizing disadvantaged communities for

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[115] Considering how to ensure continuing growth, the fundamental task of the successor tariff and the alternatives, should be addressed as discussed in Section 2.17.3.

[116] The tool may be found at: http://oehha.ca.gov/ej/ces2.html.

[117] See California Environmental Protection Agency, "Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León), October 2014 at http://www.calepa.ca.gov/EnvJustice/GHGInvest/Documents/SB535DesCom.pdf.

purposes of the programs related to the NEM successor tariff. Specifically, staff recommends using the "top 25% of communities statewide identified by CalEnviroScreen 2.0" metric used by CalEPA and CARB. CalEPA has stated its commitment to regularly revising the CalEnviroScreen tool with updated information and data.[118] The *Staff Disadvantaged Communities Paper* suggests that, in the event that the CalEnviroScreen methodology is updated in the future, the revised version of CalEnviroScreen should be used for the purposes of ongoing identification of disadvantaged communities.[119]

CEJA and SCE agree with the staff suggestion. TURN agrees that the top 25% of communities identified by Cal EnviroScreen statewide should be used, but adds additional criteria.[120] IREC, PG&E, and SEIA/Vote Solar support the use of CalEnviroScreen but do not identify a particular percentile that should be

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[118] California Communities Environmental Health Screening Tool, Version 2.0 Report, October 2014, at i: http://oehha.ca.gov/ej/pdf/CES20FinalReportUpdateOct2014.pdf

[119] In its "Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León)," CalEPA states that it "will work with local and regional jurisdictions to review our data and verify results. If recalculation of a community's CalEnviroScreen2.0 score shows that it should have been identified as a disadvantaged community, we will add that community to the list for this designation. And we will not remove a community from the list for the current designation if recalculation of their CalEnviroScreen 2.0 score shows that they were incorrectly identified as a disadvantaged community. Accordingly, any changes to the current version of CalEnviroScreen 2.0 will have no bearing on funding decisions already in process." California Environmental Protection Agency, "Designation of Disadvantaged Communities Pursuant to Senate Bill 535 (De León), October 2014 at 15: http://www.calepa.ca.gov/EnvJustice/GHGInvest/Documents/SB535DesCom.pdf

[120] TURN suggests that an income requirement should be added; for example, using income eligibility criteria from existing programs, such as SASH and MASH.

used.[121] SDG&E supports using CalEnviroScreen, but using it to identify the top 20% of communities in each IOU's service territory.

GRID Alternatives proposes using CalEnviroScreen to identify the top 25% of communities in each IOU's service territory but adds additional criteria.[122] Brightline/SALEF, Everyday Energy, Greenlining and MASH Coalition also support expanding the definition beyond CalEnviroScreen identified communities.

Several parties express concern that relying on CalEnviroScreen alone to define disadvantaged communities would exclude some rural communities with high poverty and pollution.[123] GRID Alternatives specifically notes that "many rural communities and all tribal reservations north of San Francisco and rural, coastal communities from Monterey to Los Angeles" are not included in the top 25% of communities identified by CalEnviroScreen 2.0 statewide.[124]

ORA, alone among the parties, proposes a definition based solely on income, proposing that all customers who qualify for the MASH, SASH or CARE programs be defined as members of a disadvantaged community.

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[121] IREC and SEIA/Vote Solar also support adding low-income customers outside disadvantaged communities.

PG&E recommends that an income requirement be added, similar to TURN's proposal.

[122] GRID Alternatives casts the widest net, adding: residents of affordable housing complying with Section 2852; CARE-eligible customers; as well as economically-distressed communities as defined through IRS Qualified Census Tracts, federally-designated Empowerment Zones, Enterprise Communities and Targeted Employment Areas. GRID Alternatives also proposes including an individual income requirement, such as 80% or below Area Median Income.

[123] Brightline/SALEF, GRID Alternatives, Greenlining, IREC, and SEIA/Vote Solar, are in this group.

[124] GRID Alternatives Proposal at 10.

Although many of the parties' suggestions have some merit, the best choice here is the simplest. A "disadvantaged community" should be idefined as a community that is identified, by using CalEnviroScreen 2.0, as among the top 25% of communities statewide. This is the method developed and used by CalEPA and CARB, the agencies with expertise in this area. The Commission should use it for purposes of developing the alternatives for disadvantaged communities under Section 2827.1(b)(1).

In making this choice, it is important to note that the Legislature used the term "disadvantaged communities," not "low-income individuals." CEJA points out that AB 327 uses both "disadvantaged communities" and "low-income" to refer to particular groups of customers and argues that the Legislature clearly intended to distinguish between the terms. Those proposals that seek to refocus on low-income individuals, or add criteria in order to allow low-income individuals not living in disadvantaged communities to participate, miss the mark. While there may be value in other contexts to the definitional suggestions made by some parties, this legislation is about "residential customers in disadvantaged communities."

Although the Legislature did not specifically cite to H&S Code § 39711 in AB 327, as it did in AB 693, it is clear that the concept of "disadvantaged communities" as articulated in H&S Code § 39711 and implemented by CalEPA has become the standard for use by state agencies.[125] In this context, SDG&E's

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[125] See, for a recent example, new Section 454.52(a)(1)(H), added by SB 350, directing the development of integrated resource plans that, among other things:

> Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

suggestion to use the top 20% of communities in each IOU service territory identified by CalEnviroScreen 2.0 is not appropriate, despite its origin in the Commission's decision in D.15-01-051. That decision set the framework for the green tariff/shared renewables (GTSR) program mandated by Sections 2831-2834. In D.15-01-051, the Commission was implementing a statutory directive to, among other things, reserve 100 MW of the mandated generating facilities for "the most impacted 20 percent" of communities. The Commission, for the sake of consistency among the various elements of the GTSR program, adopted the metric of "top 20% in each IOU service territory" to identify the relevant communities. This statute-specific metric should not be used in place of the more general, and more widely used, "top 25% under CalEnviroScreen" identification the Commission adopts for purposes of compliance with Section 2827.1(b)(1).

2.17.3. Considerations for "Growth"

The *Staff Disadvantaged Communities Paper* proposes that "growth" among residential customers in disadvantaged communities be measured by comparing the increase in the total annual capacity installed by residential customers in disadvantaged communities in each IOU service territory to a baseline, that is the year prior to the implementation of the alternative(s). PG&E, SCE, SDG&E, and TURN agree with this proposal.

Greenlining, GRID Alternatives, IREC, and SEIA/Vote Solar propose that growth should be defined as an increase in installed capacity in disadvantaged communities year-over-year.[126] Similarly, ORA proposes to define growth as an

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[126] IREC and SEIA/VOTE Solar specifically propose to define growth as an increase in installed capacity of at least 30% annually over the next several years.

increase in the total number of residential customers in disadvantaged communities participating in the NEM successor tariff year-over-year. CEJA makes a more elaborate suggestion that the alternative(s) adopted should achieve a steady increase in the rate of adoption that is at least equal to the rate of growth that the general market has experienced over the last five years. CEJA proposes that this growth rate be established as yearly MW targets.

We defer deciding on the way to measure "growth" to the next phase of this proceeding. Although the parties were able to comment on the implications of AB 693 for the alternatives for disadvantaged communities, and could make adjustments to their original proposals, this opportunity came very late in the proceeding.[127] Since, as explained more fully below, it will be useful to revisit the issue of alternatives for disadvantaged communities with more time for the parties and the Commission to consider how to develop an integrated program that includes both the program mandated by AB 693 and the additional elements we identify in this decision, it would be useful to resolve the question of what is "growth" at that time, as well.

2.18. Evaluation of Proposed Programs

2.18.1. AB 693

New Section 2870(b)(1) authorizes the Commission to use the program established by AB 693 to meet the mandate of alternatives for disadvantaged communities.[128] All parties commenting on AB 693 in response to the ALJ's

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[127] The ALJ extended the submission date to allow comments on AB 693 in the ALJ Ruling Seeking Comment on Assembly Bill 693.

[128] Section 2870(b)(1) provides:

> Adoption and implementation of the Multifamily Affordable Housing Solar Roofs Program may count toward the satisfaction of the commission's obligation to ensure

Footnote continued on next page

Ruling Seeking Comment on Assembly Bill 693 agreed that the Commission should adopt the Multifamily Affordable Housing Solar Roofs Program as part of the alternatives for disadvantaged communities. However, almost all parties, with the exception of PG&E, urge that the AB 693 program should not be the exclusive means of developing alternatives for advantaged communities.

The AB 693 program provides incentives for the installation of renewable DG for a precisely defined segment of residents of disadvantaged communities, namely residents of

> multifamily residential building[s]of at least five rental housing units that [are] operated to provide deed-restricted low-income residential housing, as defined . . . and that meet one or more of the following requirements:
>
> (A) The property is located in a disadvantaged community, as identified by the California Environmental Protection Agency pursuant to Section 39711 of the Health and Safety Code.
>
> (B) At least 80 percent of the households have incomes at or below 60 percent of the area median income, as defined in subdivision (f) of Section 50052.5 of the Health and Safety Code.

This mandate, and the statutory financial incentives accompanying it, would address a significant population, residents of larger multifamily rental buildings. It would not, however, provide any incentives for the residents of disadvantaged communities who live in other housing arrangements.[129] In order

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that specific alternatives designed for growth among residential customers in disadvantaged communities are offered as part of the standard contract or tariff authorized pursuant to paragraph (1) of subdivision (b) of Section 2827.1.

[129] Brightline/SALEF provide the example of Huntington Park, in the Los Angeles area. In Huntington Park, these parties state, more than 70% of the households would not be eligible for the AB 693 program, either because they live in single-family housing, or in rental housing with fewer than five units.

to provide a reasonable range of programmatic options, the Commission should also adopt a program or programs that are aimed at residents of disadvantaged communities whose housing is not covered by Section 2870(b)(1).

2.18.2. Party Proposals

The proposals discussed in this section are the parties' proposals as they are described in their initial proposals, adjusted by their responses to the AB 693 Ruling. Because a number of parties endorsed a variety of proposals, a proposal will be identified in this discussion by the party that initially set it forth.

IREC's CleanCARE proposes a significant modification of the CARE program, under which CARE customers could authorize the use of CARE funds to purchase renewable generation from a third-party owned facility.[130] This proposal, which would require substantial changes to the CARE program, cannot be authorized in this proceeding. The consolidated CARE docket, A.14-11-007, is the appropriate proceeding to consider such far-reaching changes to the CARE program.[131] This proposal is not adopted.

CEJA proposes a new tariff specifically for residential customers in disadvantaged communities, as well as supporting a suite of programs proposed by other parties. The tariff would establish a bill credit for customers in disadvantaged communities based on the projected long-term average residential retail rate, which CEJA estimates to be between $0.25 and $0.30/kWh. Since the Commission is in the process of comprehensively redesigning residential rates, it is simply not possible to develop a reasonable plan for a bill

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[130] Information on the CARE program may be found on the Commission's web site at http://www.cpuc.ca.gov/PUC/energy/Low+Income/home2.htm.

[131] IREC made its proposal in A.14-11-007 in April 2015.

credit based on a projected residential rate over a 20-year period, as CEJA suggests. This proposal is not adopted.

GRID Alternatives proposes continuing the existing NEM tariff for qualifying customers in disadvantaged communities and providing additional funding for SASH, as well as adopting the AB 693 program. GRID Alternatives also supports adopting an additional program proposed by other parties, although it does not recommend one specifically.

Since the full existing NEM tariff has not been effective in increasing growth in disadvantaged communities, there is no persuasive reason to hang on to it for that purpose in the future. Moreover, the proposal to continue the existing NEM tariff for residential customers in disadvantaged communities is not consistent with the Commission's approach to the NEM successor tariff, which is to increase alignment of NEM successor tariff customers with other residential customers. A program that continues the existing NEM tariff for residential customers in disadvantaged communities, even paired with other programs, should not be adopted.

PG&E changes its proposal to rely exclusively on the AB 693 Multifamily Affordable Housing Solar Roofs program. The Commission adopts the AB 693 program, but not as the exclusive component of a program for alternatives in disadvantaged communities.

SCE proposes a range of enhancements and incentives for customers in disadvantaged communities. It adopts the AB 693 program as part of its proposal. Those elements of SCE's proposal that include enhanced incentives outside the AB 693 program should not be adopted. The large incentive program under AB 693 will be a significant undertaking. Other alternatives, including the maintenance of VNM that SCE supports, should be explored before additional incentives are implemented.

SDG&E proposes installing utility-owned PV systems on multifamily housing and public schools located in the top 20% of CalEnviroScreen-designated disadvantaged communities in its service territory. The multi-family housing proposal has in essence been replaced by AB 693. SDG&E should not be authorized to run a separate, potentially conflicting program of UOG for multi-family housing.

The proposal to put utility-owned PV systems on schools and provide credit to low-income residential customers at SDG&E's proposed "Sun Credit" rate has two significant drawbacks. First, SDG&E does not provide adequate justification for a program that would be based on generation owned by SDG&E and put in its rate base, thus raising costs for all ratepayers. Nor does SDG&E provide any reason for its requirement that low-income residential customers must participate in its "Sun Credit" program, which it presents as an option, not a requirement, for all customers in its successor tariff proposal. These proposals are not adopted.

ORA proposes to expand funding for SASH if the recently approved third party ownership model proves to be successful and to adopt the AB 693 program. TURN also proposes an incentive for single-family housing, if needed, as well as the AB 693 program. Both proposals include additional funding for incentive programs other than the AB 693 program. As with SCE's proposal, these incentive proposals should not be implemented at the same time as the very large incentive program under AB 693.

One of the proposals made in the *Staff Disadvantaged Communities Paper* is to expand the availability of VNM in disadvantaged communities to create

Neighborhood VNM, under which credits from a customer-sited renewable DG system in a disadvantaged community could be allocated to any residential customer located in the same census tract and utility service territory as the host customer.[132] SEIA/Vote Solar proposes a variant on this plan, called Disadvantaged Communities VNM (DAC-VNM). DAC-VNM is similar to staff's Neighborhood VNM proposal in that it would expand VNM so that customers and projects do not have to be co-located, though DAC-VNM is more expansive. (See Section 2.7.3.9 above.)

On balance, the most reasonable course is to develop an expansion of VNM to include participation by more residential customers in disadvantaged communities. Some form of VNM expansion could address the principal barriers to participation that parties have identified, including:

- Lack of access to capital or credit to install an on-site renewable DG system;
- Unsuitable roof space, whether due to location, orientation of roof surfaces, or structural issues;
- Low levels of property ownership; and
- Marketing, outreach and linguistic barriers.

2.19. Alternatives for Growth in Disadvantaged Communities

2.19.1. Identifying Disadvantaged Communities

For purposes of providing alternatives for growth of renewable distributed generation among residential customers in disadvantaged communities, the

[132] The *Staff Disadvantaged Communities Paper* also proposes augmented funding for SASH and MASH, to be used in disadvantaged communities. This proposal, like the other augmented incentive proposals, should not be adopted while the AB 693 program is in the early stages of implementation.

relevant communities should be identified by using the CalEnviroScreen 2.0 tool.[133] The "top 25%" of communities identified using CalEnviroScreen 2.0 on a statewide basis should be the communities identified as "disadvantaged communities" for purposes of being included in the programs related to the NEM successor tariff. Although this leads to a strong asymmetry among IOU service territories, with almost no identified disadvantaged communities in SDG&E's service territory, it is more important to identify the most disadvantaged communities than it is to attempt to have a predetermined distribution of communities among service territories.

2.19.2. AB 693

The legislatively mandated incentives for installation of solar systems on multifamily affordable housing will be one part of the alternatives for disadvantaged communities developed in this proceeding.[134] For purposes of implementing the program for disadvantaged communities in connection with the NEM successor tariff, incentives for qualified housing located in

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[133] In the further consideration of alternatives for disadvantaged communities that will be undertaken in the next phase of this proceeding, the question of whether, and if so how often, to update the list of disadvantaged communities, should also be considered.

[134] Section 2870(a)(3) provides:

> "Qualified multifamily affordable housing property" means a multifamily residential building of at least five rental housing units that is operated to provide deed-restricted low-income residential housing, as defined in clause (i) of subparagraph (A) of paragraph (3) of subdivision (a) of Section 2852, and that meets one or more of the following requirements:
>
> (A) The property is located in a disadvantaged community, as identified by the California Environmental Protection Agency pursuant to Section 39711 of the Health and Safety Code.
>
> (B) At least 80 percent of the households have incomes at or below 60 percent of the area median income, as defined in subdivision (f) of Section 50052.5 of the Health and Safety Code.

disadvantaged communities as identified in this proceeding will be considered part of the successor tariff alternatives for disadvantaged communities. In the next phase of this proceeding, the design and administration of the AB 693 program will be considered.

2.19.3. Neighborhood/Extended VNM

Because the program authorized by AB 693 does not extend to any single family dwellings, and is limited to a subset of multi-family buildings, it is reasonable to adopt additional program elements that will provide alternatives for growth among residents of dwellings in disadvantaged communities that are not eligible for incentives under AB 693. The approach identified by Energy Division staff as "neighborhood VNM" is most likely to address the barriers identified by staff and the parties to growth of residential renewable DG in disadvantaged communities.

Since parties have identified some important issues in implementing such an approach, principally the question of how to ensure that enough households are available to participate in any one neighborhood VNM project, we adopt the neighborhood (or expanded) VNM approach in principle now. We will return to the structure and implementation of an expanded VNM program, including issues related to identifying a critical mass of potential participants, in the next phase of this proceeding.

2.20. Further Work

We defer to the next phase of this proceeding fully characterizing the VNM expansion to be implemented. Parties should be given the opportunity to review the possibilities for an expanded VNM for residents of disadvantaged communities, and to offer additional comments about the design and implementation of such a program, in light both of the adoption of the AB 693 program, and the possibilities for expanded VNM that may be developed once it is clear that it is the program of choice.

The next phase of this proceeding will, therefore, include these elements of program design of the alternatives for growth of renewable distributed generation among residential customers in disadvantaged communities:

1. Plan for implementation and administration of the Multifamily Affordable Housing Solar Roofs program established by AB 693;
2. Design of an expanded VNM program;
3. Development of criteria for evaluating whether the programs adopted are fostering growth of alternatives in disadvantaged communities; and
4. Design of measurement and evaluation plans.

In the next phase of this proceeding, the information provided by the IOUs in response to the ALJ's AB 693 Ruling, about the top 25% of disadvantaged communities statewide that are located in their service territories, will be utilized to design and implement the programs providing alternatives for growth in disadvantaged communities.

3. Next Steps

The most immediate next step is for the IOUs to submit, via advice letter, their NEM successor tariffs, updated VNM tariffs, and updated NEMA tariffs in accordance with this decision.

A second phase of this proceeding will continue consideration of alternatives for disadvantaged communities, within the parameters set by this decision, leading to the designation of appropriate alternatives and a plan to implement them. Also in the next phase of this proceeding, further consideration will be given to consumer protection, including but not limited to development of information packets for potential NEM customers; marketing, education, and outreach; and measurement and evaluation with respect to the NEM successor tariff.

4. Comments on Proposed Decision

The proposed decision of ALJ Simon in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

Comments were filed on ____, by____, and reply comments were filed on ____ by ____.

5. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Anne E. Simon is the assigned ALJ for this proceeding.

Findings of Fact

1. Approximately 90% of the installations of renewable DG on customer premises using the existing NEM tariff are on the premises of residential customers.

2. In D.15-07-001, the Commission determined that a fixed charge should not be implemented for residential customers until after the reduction in tiers from four to two for residential rates is complete and after default TOU for residential customers has been implemented.

3. In D.15-07-001, the Commission found that fixed charges, including demand charges, are not well-understood by the majority of residential customers.

4. In D.15-07-001, the Commission initiated a process for standardizing categories of potential fixed charges for residential customers. This process will begin with Phase 2 of PG&E's GRC in March 2016.

5. In D.15-07-001, the Commission initiated a process for developing default TOU rates for residential customers, with the goal of instituting default TOU rates for residential customers in 2019.

6. In R.14-08-013, the distribution resources planning proceeding, the Commission has begun evaluation of the locational benefits of distributed resources; identification of additional utility spending necessary to integrate cost-effective distributed resources; identification of barriers to the deployment of distributed resources; and development of analytic tools to improve understanding of distributed resources.

7. In R.14-10-003, the integration of distributed energy resources proceeding, the Commission has begun identification of tariffs, contracts, or other mechanisms to stimulate deployment of distributed resources; proposed methods to coordinate existing programs, tariffs, and incentives to maximize the net benefits of distributed resources; and possible mechanisms to compensate owners of distributed resources for the locational values they provide.

8. Some of the work identified to be done in R.14-08-013 and R.14-10-003 has been begun; none of it has been completed at this time.

9. It is reasonable to conclude that the analysis and programmatic examinations being undertaken in R.14-08-013 and R.14-10-003 will, when completed, provide information and analysis relevant to the determination of the benefits and costs of the NEM successor tariff to all customers and the electric system.

10. It is reasonable to conclude, on the basis of the stated plans in those proceedings, that the analysis and programmatic examinations being undertaken in R.14-08-013 and R.14-10-003 will not be completed prior to the time the NEM successor tariff must be in effect.

11. Based on the analytic tools and information currently available for use by the Commission, it is not possible to come to a comprehensive, reliable, and analytically sound determination of the benefits and costs of the NEM successor tariff to all customers and the electric system.

12. SCE has not demonstrated in this proceeding that its proposed fixed grid access charge for the NEM successor tariff is reasonable in light of the Commission's prior determinations about the timing of potential fixed charges for residential customers.

13. SDG&E has not demonstrated in this proceeding that its proposed fixed system access fee for the NEM successor tariff is reasonable in light of the Commission's prior determinations about the timing of potential fixed charges for residential customers.

14. PG&E has not demonstrated in this proceeding that residential customers taking service under a NEM successor tariff would understand its proposed demand charges any more readily than other residential customers understand demand charges.

15. SDG&E has not demonstrated in this proceeding that residential customers taking service under a NEM successor tariff would understand its proposed grid use charge, a type of demand charge, any more readily than other residential customers understand demand charges.

16. In California, there are hundreds of firms that install customer-sited solar PV systems, with about 10 firms operating statewide and the remainder in more local areas.

17. Several elements go in to the installed price of a customer-sited solar PV system, including the cost of hardware, permitting costs, and customization of installations for the customer's site needs and preferences.

18. Although the cost of fundamental hardware parts for customer-sited solar PV systems have fallen sharply in the past five years, projections for further declines are not uniform.

19. It is not necessary to project the costs of customer-sited solar PV installations with a high degree of precision in order to make reasonable determinations about the elements of the NEM successor tariff.

20. Parties to this proceeding agree that the projection of the costs for installing customer-sited solar PV systems in California over the next eight to ten years that is reflected in the "base case" solar price of the Public Tool is a reasonable projection on which to base the design of the NEM successor tariff.

21. An installed capacity fee is a monthly charge levied on the number of kW of capacity installed in a customer-generator's system.

22. ORA has not demonstrated that either the initial monthly amount of its proposed installed capacity fee or the escalation of the monthly amount based on an increasing proportion of capacity under the NEM successor tariff in an IOU's service territory is cost-based.

23. NRDC's proposal for a NEM successor tariff is not sufficiently specific to be considered at this time.

24. TURN has not demonstrated that the value of customer-sited renewable DG can be determined with sufficient accuracy to support its proposed Value of Distributed Energy tariff.

25. CARE has not proposed any method of determining the avoided cost that would be necessary for its proposal that IOUs enter into power purchase agreements with qualifying facilities up to 3 MW in size.

26. A customer-sited renewable DG system sized larger than 1 MW will not have significant impact on the distribution grid if the customer pays all Rule 21

interconnection costs, which will both cover the IOU's costs and ensure that the projects themselves will not have significant impact on the distribution grid.

27. Continuing net energy metering with NEM customers paying charges for interconnection and paying nonbypassable charges for all electricity consumed from the grid is likely to allow customer-sited renewable DG to continue to grow sustainably.

28. Most classes of non-residential customers are required to be on TOU tariffs.

29. Residential NEM successor tariff customers on TOU rates will have similar incentives to reduce their electricity use and/or use electricity at times more advantageous to grid reliability as do residential customers on TOU rates who are not NEM customers.

30. The participation of residential customers using the NEM successor tariff in the default TOU pilots mandated by D.15-07-001 or in other available TOU rates, beginning in 2018 could provide useful information to customers, the IOUs, and the Commission, would engage NEM successor tariff customers and third-party service providers in the design of residential TOU rates, and would encourage preferred system design of customer-generators' systems.

31. Continuing net energy metering with NEM successor tariff customers paying charges for interconnection and nonbypassable charges for all electricity consumed from the grid, as well as being on an applicable TOU rate, will provide electric service to customers on the NEM successor tariff at just and reasonable rates.

32. It is reasonable to continue the VNM tariff, updated to include the requirements of the NEM successor tariff.

33. No adverse effects of the ability to have multiple service delivery points for premises under the MASH VNM tariff have been identified by the IOUs in this proceeding.

34. It is reasonable to allow the use of multiple service delivery points for all premises under the updated VNM tariff.

35. The NEMA tariff has been in effect for approximately two years.

36. No adverse effects of the NEMA tariff have been identified by the IOUs in this proceeding.

37. It is reasonable to continue the NEMA tariff, updated to include the requirements of the NEM successor tariff.

38. The AB 693 program would address barriers to the growth of customer-sited renewable DG for residents of larger multifamily rental buildings in disadvantaged communities, but it would not provide any incentives for the residents of disadvantaged communities who live in other housing arrangements.

39. An expansion of VNM to include participation by more residential customers in disadvantaged communities is most likely to address the barriers to growth of residential renewable DG in disadvantaged communities that are not addressed by the AB 693 Multifamily Affordable Housing Solar Roofs program.

40. CalEPA and CARB use CalEnviroScreen to fulfill the legislative requirement of identifying disadvantaged communities for purposes of distribution of certain funds from the Greenhouse Gas Reduction Fund. These agencies have concluded that a "disadvantaged community" is a community that appears among the top 25% of census tracts identified by CalEnviroScreen 2.0 statewide.

41. It is reasonable to require minimum standards that will protect both consumers and the electric system from substandard equipment and installations.

Conclusions of Law

1. In order to ensure that customer-sited renewable DG continues to grow sustainably, the successor to the current NEM tariff should be a tariff using net energy metering, with modifications.

2. In order to better align the responsibilities of customers under the NEM successor tariff with the responsibilities of other customers in the same customer class, customers on the NEM successor tariff should pay all nonbypassable charges in each metered interval for each kilowatt-hour of electricity they consume from the grid.

3. In order to better align the charges for customers using the NEM tariff with charges for other customers, NEM customers should pay a reasonable fee for interconnection of their systems.

4. In order to ensure that interconnection fees for NEM customers are just and reasonable, any such fees for systems smaller than 1 MW in size should be based on each IOU's costs of interconnection, using the actual costs recorded in their respective June 2015 advice letters, filed in compliance with D.14-05-033 and Res. E-4610. The actual amount of the fee should include only the following costs from the advice letter filings: NEM Processing and Administrative Costs, Distribution Engineering Costs, and Metering Installation/Inspection and Commissioning Costs.

5. In order to provide for appropriate notice and customer participation, any changes to interconnection fees proposed by an IOU for its NEM customers must be made by Tier 2 advice letter, served on the service list for this proceeding, or

in any subsequent proceeding in which the NEM successor tariff is part of the scope of the proceeding.

6. In accordance with Section 2827.1(b)(7), the Commission has the authority to impose fixed charges for the NEM successor tariff that are different from the fixed charges for residential customers, but is not required to do so.

7. In order to ensure that customer-sited renewable DG systems larger than 1 MW seeking to use the NEM tariff do not have significant impact on the distribution system, customers installing such systems should be required to pays all Rule 21 interconnection and upgrade costs.

8. In order to promote consistency with the Commission's process for making changes to the rate structure for residential customers, the NEM successor tariff should not include any fixed charges, including but not limited to demand charges, grid access fees, or similar charges, prior to such time as the Commission authorizes the introduction of fixed charges for all residential customers.

9. Residential customers using the NEM successor tariff whose systems are interconnected at any time during 2018, and at any time during 2019 that is prior to the institution of default residential TOU rates, should take service on an existing TOU rate or participate in any TOU pilots that are designed to include NEM successor tariff customers.

10. In order to better align the NEM successor tariff with residential customers' responsibilities generally, to promote customers' awareness of, and to provide incentives to reduce, the impact of their electricity usage on the electrical system, once the Commission has instituted default TOU rates for residential customers, all customers using the NEM successor tariff established by this decision should be required to stay on their default TOU rate, or on another

available TOU rate otherwise applicable to them, in order to begin or continue to use the NEM successor tariff.

11. In order to promote consistency in the treatment of customers under the existing NEM tariff and customers under the NEM successor tariff established by this decision, customers should be able use the NEM successor tariff as it existed at the time they interconnected for 20 years from the year of the interconnection of their system.

12. In order to promote fairness in the treatment of customers under the existing NEM tariff and customers under the NEM successor tariff established by this decision, any customer that switches from the existing NEM tariff to the NEM successor tariff pursuant to Ordering Paragraph 2 of D.14-03-041 may continue to use the NEM successor tariff until the expiration of 20 years from the original year of interconnection of the customer's system.

13. Consistent with any requirements of Section 2827(b)(4)(C), Armed Forces bases and facilities should be eligible to install renewable distributed energy systems larger than 1 MW in size pursuant to the NEM successor tariff adopted in this decision.

14. In light of the substantial work that the Commission has undertaken, but not yet completed, that will lead to better analytic methods and information with respect to the specific benefits of distributed energy resources, and the substantial work that the Commission has undertaken, but not yet completed, that will lead to significant changes to residential rates (including the institution of default TOU rates), the Commission should determine that the benefits and costs of the NEM successor tariff to all customers and the electric system are not well characterized at this time.

15. The NEM successor tariff adopted in this decision complies with the requirement of Section 2827.1(b)(7) that customer generators are to be provided electric service at rates that are just and reasonable.

16. In order to ensure that the NEM successor tariff is consistent with Commission policy on distributed energy resources, makes use of relevant information about locational benefits and optimal distributed generation resources, and is appropriately aligned with changes to retail rates for residential and small commercial customers, the successor tariff adopted in this decision should be reviewed in 2019.

17. In order to ensure consistency with the methods developed and used by CalEPA and CARB, a "disadvantaged community" for purposes of implementing Pub. Util. Code Section 2827.1(b)(1) should be defined as a community that is identified by using CalEnviroScreen 2.0 as among the top 25% of communities statewide.

18. In order to provide a reasonable range of programmatic options for growth of renewable DG among residential customers in disadvantaged communities, the Commission should use the program authorized by AB 693 as one part of the alternatives for disadvantaged communities and should also adopt a program expanding VNM that supports residents of disadvantaged communities whose housing is not covered by Section 2870(b)(1).

19. In order to allow the development of alternatives for disadvantaged communities to proceed expeditiously, an approach using an expanded VNM should be adopted in principle now, and the structure and implementation of this program should be addressed in the next phase of this proceeding.

20. In order to promote safety and reliability of customer-sited solar PV systems, each IOU should verify, as part of each interconnection request for a

NEM successor tariff system, that all major solar system components are on the verified equipment list maintained by the CEC, and other equipment, as determined by the utility, should be verified as having safety certification from an NRTL.

21. In order to promote safety and reliability of customer-sited renewable distributed generation systems, each IOU should verify, as part of each interconnection request for a NEM successor tariff system, that a warranty of at least 10 years has been provided on all equipment and the installation of that equipment.

22. In order to facilitate an effective transition to the NEM successor tariff, the Director of Energy Division should be authorized to take appropriate steps, including but not limited to collecting data, holding workshops, and developing reports and information tools, that would contribute to the Commission's administration of the NEM successor tariff and any programs that implement alternatives for growth of renewable DG among residential customers in disadvantaged communities, as well as advance consumer protection for customers on the NEM successor tariff and help to prepare for the Commission's review of the NEM successor tariff and alternatives for disadvantaged communities anticipated to be undertaken in 2019.

23. In order to continue implementation of the NEM successor tariff and related programs and requirements, a second phase of this proceeding should be undertaken.

24. In order to ensure a timely transition to the NEM successor tariff, this decision should be effective immediately.

O R D E R

IT IS ORDERED that:

1. Not later than 30 days after the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 2 advice letter with their respective net energy metering successor tariffs in accordance with each and every requirement of this decision.

2. In their successor net energy metering tariffs, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each set an interconnection fee for customer-generators systems less than one megawatt in size by using the actual costs recorded in their respective June 2015 advice letters, filed in compliance with Decision 14-05-033 and Resolution E-4610. The actual amount of the fee must include only the following costs from the advice letter filings: NEM Processing and Administrative Costs, Distribution Engineering Costs, and Metering Installation/Inspection and Commissioning Costs.

3. In their respective net energy metering successor tariffs, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each take account of the special requirements for Armed Forces bases and facilities, as defined in Public Utilities Code Section 2827(b)(4)(C).

4. Not later than 30 days after the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 2 advice letter implementing their

respective successor virtual net metering tariffs in accordance with each and every requirement of this decision.

5. Not later than 30 days after the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 2 advice letter implementing their respective successor net metering aggregation tariffs in accordance with each and every requirement of this decision.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each develop tracking and reporting tools that will allow an evaluation of growth of customer-sited renewable distributed generation under the net energy metering successor tariff, in accordance with instructions from the Director of Energy Division.

7. The Director of Energy Division is authorized to take appropriate steps, including but not limited to collecting data, holding workshops, and developing reports and information tools, that would contribute to the Commission's administration of the NEM successor tariff and any programs that implement alternatives for the growth of renewable distributed generation among residential customers in disadvantaged communities, as well as advance consumer protection for customers on the NEM successor tariff and help to prepare for the Commission's review of the NEM successor tariff and alternatives for disadvantaged communities anticipated to be undertaken in 2019.

8. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company must collect data in each utility's successor net energy metering interconnection application to verify that the

system being interconnected has a warranty as well as equipment in compliance with the requirements of this decision.

9. Rulemaking 14-07-002 remains open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

APPENDIX A

Appendix A – Public Utilities Code Section 2827.1

APPENDIX A

PUBLIC UTILITIES CODE SECTION 2827.1

Section 2827.1

(a) For purposes of this section, "eligible customer-generator," "large electrical corporation," and "renewable electrical generation facility" have the same meanings as defined in Section 2827.

(b) Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015. The commission may develop the standard contract or tariff prior to December 31, 2015, and may require a large electrical corporation that has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827 to offer the standard contract or tariff to eligible customer-generators. A large electrical corporation shall offer the standard contract or tariff to an eligible customer-generator beginning July 1, 2017, or prior to that date if ordered to do so by the commission because it has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827. The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section. In developing the standard contract or tariff, the commission shall do all of the following:

(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

(2) Establish terms of service and billing rules for eligible customer-generators.

(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.

(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.

(5) Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of

more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements.

(6) Establish a transition period during which eligible customer-generators taking service under a net energy metering tariff or contract prior to July 1, 2017, or until the electrical corporation reaches its net energy metering program limit pursuant to subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827, whichever is earlier, shall be eligible to continue service under the previously applicable net energy metering tariff for a length of time to be determined by the commission by March 31, 2014. Any rules adopted by the commission shall consider a reasonable expected payback period based on the year the customer initially took service under the tariff or contract authorized by Section 2827.

(7) The commission shall determine which rates and tariffs are applicable to customer generators only during a rulemaking proceeding. Any fixed charges for residential customer generators that differ from the fixed charges allowed pursuant to subdivision (f) of Section 739.9 shall be authorized only in a rulemaking proceeding involving every large electrical corporation. The commission shall ensure customer generators are provided electric service at rates that are just and reasonable.

(c) Beginning July 1, 2017, or when ordered to do so by the commission because the large electrical corporation has reached its capacity limitation of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827, all new eligible customer-generators shall be subject to the standard contract or tariff developed by the commission and any rules, terms, and rates developed pursuant to subdivision (b). There shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017. An eligible customer-generator that has received service under a net energy metering standard contract or tariff pursuant to Section 2827 that is no longer eligible to receive service shall be eligible to receive service pursuant to the standard contract or tariff developed by the commission pursuant to this section.

(End of Appendix A)

APPENDIX B

Appendix B – Summary of Standard Practice Manual Cost Tests

APPENDIX B

Summary of Standard Practice Manual Cost Tests

All demand-side resource programs that are approved by the Commission undergo a cost-effectiveness analysis. While the specific tests and their applications vary among resources, the foundation of cost-effectiveness analysis is based on the Standard Practice Manual. The Standard Practice Manual was originally developed in 1983, and has been revised a number of times since.[1]

Cost Test	Abbreviation	Key Question	Summary Approach
Participant Cost Test	PCT	Will the participants benefit over the measure life?	Participant's Perspective: Comparison of costs and benefits of consumer installing the measure
Program Administrator Cost Test	PAC	Will the utility revenue requirement increase or decrease?	Utility's Perspective: Comparison of Program Administrator costs to supply side resource costs
Ratepayer Impact Measure	RIM	Will utility rates increase or decrease?	Non-Participant's Perspective: Comparison of administrator costs and utility bill reductions to supply side resource costs
Total Resource Cost Test	TRC	Is the total amount spent on the technology more or less than the cost savings to the utility that result from its installation?	Society's Perspective: Comparison of Program Administrator and customer costs to utility resource savings
Societal Cost Test	SCT	Same as TRC, but with inclusion of non-monetized societal benefits.	Society's Perspective: Comparison of society's costs of the measure to resource savings and non-cash costs and benefits

(End of Appendix B)

[1] Available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf.

APPENDIX C

Appendix C – Summary Tables of Public Tool Results

APPENDIX C

Summary Tables of Public Tool Results

Notes on tables:

Appendix C presents results of key metrics of Public Tool runs of parties' NEM Successor Tariff Proposals. The metrics selected for inclusion in the results table are based on the metrics that were highlighted in the Energy Division Staff Paper, released June 4, 2015. They include: Forecasted Installations from 2017-2025, Implied Payback of Renewable DG Systems, Participant Benefit/Cost Ratio, All Generation Non-Participant Benefit/Cost Ratio, and Export Only Non-Participant Benefit/Cost Ratio. Additional metrics (Total Resource Cost Test Benefit/Cost Ratio, and Societal Cost Test Benefit/Cost Ratio) were included in Table 2 results to reflect the emphasis placed on these additional metrics in the proposals filed by the parties included in that table.

Table 1 presents results provided by parties in their August 3, 2015 NEM Successor Tariff Proposal filings, who evaluated their proposal using both the High and Low DG Value Cases.

Table 2 presents results provided by parties in their August 3, 2015 NEM Successor Tariff Proposal filings, who evaluated their proposal using only the Additional DG Value Case, and/or modified the Public Tool.

Table 3 presents results of Public Tool runs conducted by Energy Division Staff of each party's proposal, utilizing the Scenarios the parties submitted with their August 3, 2015 proposal filings.

All results presented across the three tables are for Public Tool runs that utilized a 2 Tiered Default Residential Rate. While the June 4th ALJ Ruling required parties to evaluate their proposals using three different Default Residential Rates (2 Tiered, TOU 2-8pm On Peak, and TOU 4-8pm on Peak), only results of the 2 Tiered runs are presented in the tables, as these are the only rates that were authorized by the Commission in D.15-07-001. While we expect default TOU for residential customers to go into effect in 2019, we do not have any indication of what those rates would look like, therefore utilizing the 2 Tiered rates for evaluation purposes can serve as a reasonable proxy for rates that may be in place over the entire evaluation period.

Table 1: Successor Tariff Public Tool Results as Reported in Party Proposal (2 Tier Rate Structure; High/Low DG Value Scenarios)

Party	Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)	ALL GENERATION : Average Non-Participant Benefit/Cost Ratio (RIM)	EXPORT ONLY: Average Non-Participant Benefit/Cost Ratio (RIM)
ORA	Low	2 Tiered	NEM + Installed Capacity Fee $2	12,581	7.4	1.33	0.25	
ORA	Low	2 Tiered	NEM + Installed Capacity Fee $10	8,262	9.14	1.07	0.34	
PG&E*	Low	2 Tiered	NEM onsite, Gen Rate for Exports, Demand Charge	2,106		1.02	0.38	
SCE*	Low	2 Tiered	NEM onsite, Avoided Cost for Exports, Grid Charge	1,980	10.8	1.01	0.46	0.84
SDG&E*	Low	2 Tiered	Default Unbundled Rate	632	7.8	1.26	0.33	
SDG&E*	Low	2 Tiered	Sun Credit	292	14.5	0.68	0.59	
TURN	Low	2 Tiered	Avoided Cost All Gen ($0 DGA)	2,194	20.1	0.49	0.905	
TURN	Low	2 Tiered	Avoided Cost All Gen ($0/10/kWh DGA)	4,059	9.6	1.02	0.504	
ORA	High	2 Tiered	NEM + Installed Capacity Fee $2	16,775	5.18	1.9	0.5	
ORA	High	2 Tiered	NEM + Installed Capacity Fee $10	15,255	6.78	1.45	0.65	
PG&E*	High	2 Tiered	NEM onsite, Gen Rate for Exports, Demand Charge	6,213		1.7	0.72	
SCE*	High	2 Tiered	NEM onsite, Avoided Cost for Exports, Grid Charge	1,745	6.5	1.94	0.73	1.28
SDG&E*	High	2 Tiered	Default Unbundled Rate	535	3.7	2.66	0.47	
SDG&E*	High	2 Tiered	Sun Credit	1,117	7.2	1.37	0.97	
TURN	High	2 Tiered	Avoided Cost All Gen ($0 DGA)	10,937	7.4	1.33	0.928	
TURN	High	2 Tiered	Avoided Cost All Gen ($0.10/kWh DGA)	16,505	4.35	2.26	0.464	

*All Results for Party's Own Utility Service Territory Onlyy

Table 2: Successor Tariff Public Tool Results as Reported in Party Proposal (2 Tier Rate Structure; Additional DG Value Scenarios/Modified Public Tool)

Party	Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)	ALL GENERATION: Average Non-Participant Benefit/Cost Ratio (RIM)	EXPORT ONLY: Average Non-Participant Benefit/Cost Ratio (RIM)
CALSEIA	Additional	2 Tiered	Full Retail NEM				0.83	0.77
SEIA - Vote Solar	Additional	2 Tiered	Full Retail NEM	8,000	6.8	1.44	1.05	
TASC	Additional	2 Tiered	Full Retail NEM			1.42		

Table 3: Successor Tariff Public Tool Results Modeled by Energy Division Staff Based on Scenarios Submitted by Parties (2 Tier Rate Structure; High/Low DG Value Scenarios)

Party	Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)	ALL GENERATION: Average Non-Participant Benefit/Cost Ratio (RIM)	EXPORT ONLY: Average Non-Participant Benefit/Cost Ratio (RIM)
CALSEIA	Low	2 Tiered	Full Retail NEM	11,985	7.8	1.25	0.22	0.17
Federal Executive Agencies	Low	2 Tiered	Full Retail NEM	11,985	7.8	1.25	0.22	0.17
NRDC	Low	2 Tiered	Full Retail NEM	11,985	7.8	1.25	0.22	0.17
ORA	Low	2 Tiered	NEM + Installed Capacity Fee $2	12,581	8.2	1.19	0.22	0.17
ORA	Low	2 Tiered	NEM + Installed Capacity Fee $10	8,262	9.4	1.04	0.32	0.22
PG&E	Low	2 Tiered	NEM onsite, Gen Rate for Exports, Demand Charge	5,389	8.67	1.13	0.36	0.54
SCE	Low	2 Tiered	NEM onsite, Avoided Cost for Exports, Grid Charge	4,890	10.0	0.98	0.43	0.75
SDG&E	Low	2 Tiered	Sun Credit	2,210	13.2	0.72	0.57	0.53
SDG&E	Low	2 Tiered	Default Unbundled Rate	5,068	8.9	1.10	0.41	0.88
SEIA - Vote Solar	Low	2 Tiered	Full Retail NEM	11,985	7.8	1.25	0.22	0.17
TURN	Low	2 Tiered	Avoided Cost All Gen ($0 DGA)	2,194	15.5	0.60	0.92	0.83
TURN	Low	2 Tiered	Avoided Cost All Gen + $0.10 DGA	4,059	11.2	0.88	0.50	0.49
TASC	Low	2 Tiered	Full Retail NEM	11,985	7.8	1.25	0.22	0.17
CALSEIA	High	2 Tiered	Full Retail NEM	16,047	5.1	1.91	0.47	0.40
Federal Executive Agencies	High	2 Tiered	Full Retail NEM	16,047	5.1	1.91	0.47	0.40
NRDC	High	2 Tiered	Full Retail NEM	16,047	5.1	1.91	0.47	0.40

Table 3 Continued: Successor Tariff Public Tool Results Modeled by Energy Division Staff Based on Scenarios Submitted by Parties (2 Tier Rate Structure; High/Low DG Value Scenarios)

Party	Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)	ALL GENERATION: Average Non-Participant Benefit/Cost Ratio (RIM)	EXPORT ONLY: Average Non-Participant Benefit/Cost Ratio (RIM)
ORA	High	2 Tiered	NEM + Installed Capacity Fee $2	16,775	5.4	1.83	0.48	0.39
ORA	High	2 Tiered	NEM + Installed Capacity Fee $10	15,255	6.6	1.48	0.60	0.43
PG&E	High	2 Tiered	NEM onsite, Gen Rate for Exports, Demand Charge	11,327	6.61	1.49	0.68	0.95
SCE	High	2 Tiered	NEM onsite, Avoided Cost for Exports, Grid Charge	6,789	6.6	1.49	0.71	1.21
SDG&E	High	2 Tiered	Sun Credit	10,946	9.3	1.06	0.90	0.84
SDG&E	High	2 Tiered	Default Unbundled Rate	5,756	6.1	1.62	0.66	1.36
SEIA - Vote Solar	High	2 Tiered	Full Retail NEM	16,047	5.1	1.91	0.47	0.40
TASC	High	2 Tiered	Full Retail NEM	16,047	5.1	1.91	0.47	0.40
TURN	High	2 Tiered	Avoided Cost All Gen ($0 DGA)	10,937	9.1	1.08	0.91	0.84
TURN	High	2 Tiered	Avoided Cost All Gen + $0.10 DGA	16,505	5.3	1.85	0.46	0.43

(End of Appendix C)

APPENDIX D

CA.GOV California Public Utilities Commission

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(End of Appendix D)