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**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)

PROPOSAL FOR AB 327 SUCCESSOR TARIFF OF THE ALLIANCE FOR SOLAR CHOICE

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SUMMARY OF THE PROPOSAL FOR AB 327 SUCCESSOR TARIFF OF THE ALLIANCE FOR SOLAR CHOICE

The Alliance for Solar Choice (TASC) presents this summary of our proposal for a net energy metering (NEM) successor tariff/contract consistent with prior rulings in this docket.

At present, California ratepayers are uniformly able to avail themselves of a simple tariff that allows them to receive a full retail rate credit for output from their customer-sited renewable distributed generation (DG) when production from their DG system produces more energy than needed on-site. As many stakeholders across the country have noted, this simple NEM framework essentially allows the meter to "run backwards" during periods of excess energy production. Because NEM is a straightforward concept for energy consumers to understand, it has facilitated the installation of well over 200,000 DG systems in California alone. NEM - where the customer receives a bill credit at the full retail rate - has become a foundational policy underpinning the success of California's efforts to date to bring solar energy into the energy resource mainstream and harness customer investment in DG resources to meet California's clean energy goals, including substantial reductions in greenhouse gas (GHG) emissions.

Below we explain in detail the key assumptions and modeling changes TASC has made to the Public Tool and provide rationales for each of the changes. These changes include corrections to various avoided cost assumptions, the addition of appropriate externalities, and correcting the rates input into the Public Tool for the utilities, among other things.

TASC proposes a successor tariff that continues NEM under the same rules and structures as today with one modest change, namely that NEM successor tariff participants pay the public purpose program (PPP) component of the non-bypassable charges (NBCs) after a transition period. In other words, credits for exported energy would continue to be credited on a customer's bill on a monthly basis under a tariff open to all customers installing renewable DG facilities. Customers with facilities below one megawatt (MW) would continue to receive exemptions from interconnection fees and system upgrade costs as well as exemption from standby charges and other NBCs (except for PPP charges). We are not aware of any outstanding statutory, policy or practical considerations that remain outstanding in considering the continuation of NEM.

As the Commission requested, TASC has used the Public Tool to analyze the costs and benefits of our successor tariff proposal using both the Book Ends provided in the Staff Tariff Report and our own Third Case. Due to limitations of the Public Tool, it is not possible to model the aspect of our proposal where PPP charges become non-avoidable after a transition period. First, it is not possible to phase in a rate element over time. Second, it is not possible to differentiate between PPP charges and other NBCs (nuclear decommissioning, Department of Water Resources (DWR) bonds) in the tool. To demonstrate the directional impact we would expect after this transition, we have modeled a case where all NBCs are non-avoidable for the portion of generation that receives NEM credits (referred to in the basic rate inputs tab as "Exports Non-avoidable (asymmetric)".

In addition to TASC's successor tariff proposal and NBC transition sensitivity, TASC includes the following sensitivity cases in an effort to demonstrate the impact of a few key assumption changes on cost recovery, adoption, and the cost-effectiveness tests.

- $15 Minimum Bill on all residential ratepayers
    - In this sensitivity case, TASC attempts to quantify the impacts on cost recovery from moving to a minimum bill higher than the level recently approved in the Commission's recent Residential Rates Final Decision[1].

[1] *See* Decision No. (D.) 15-07-001, issued July 13, 2015 in Rulemaking No. (R.) 12-06-013.

- $10 Fixed Charge on all residential ratepayers
    - In this sensitivity case, TASC attempts to quantify the impacts on cost recovery and adoption from moving to a fixed charge at a level that can be reasonably expected after implementation of default TOU rates in the 2019 timeframe.
- 50% RPS with DG Renewable Energy Credits (RECs) counting as bucket 1
    - In this sensitivity case, we modeled our NEM successor tariff under the option of all renewable energy credits (RECs) produced by NEM systems being eligible for Portfolio Content Category 1 treatment within the Renewable Portfolio Standard (RPS) program with a 50% goal by 2030, as set forth in pending legislation. There is no statutory prohibition to RECs produced by NEM facilities from being utilized in this manner.[2] While TASC is not asking the Commission to revisit the treatment of RECs produced by NEM systems at this time, this sensitivity analysis also

[2] Sec. 399.16(b)(1)(A) identifies the first category of RECs as those produced by an eligible renewable energy resource that has its first point of interconnection with distribution facilities used to serve end users. Despite the fact that the Decision recognized that customer-sited DG interconnected to a California utility met the criterion in Sec. 399.16(b)(1) for generation with the first point of interconnection to the distribution system, the Decision found that behind-the-meter RECs only qualified as Category 3 RECs. See D.11-12-052 at p. 35. The Decision based this finding on three points: (1) the Decision implicitly appeared to assume that behind-the-meter RECs were unbundled RECs; (2) the Decision argued that AB 920 recognized that behind-the-meter RECs are different from the sale under AB 920 of both energy and RECs to a retail seller by the owner of an RPS-eligible system; and (3) stated that conferring additional value on [behind-the-meter RECs] was not warranted by statute or Commission decision after recognizing that customer-sited DG already produces a benefit for ratepayers by reducing the total retail sales and, thus, reducing the amount of RPS-eligible procurement required to meet statutory mandates. See D.11-12-052 at pp. 34-36. TASC believes that the landscape of California's energy policy has changed and therefore none of these rationales have enough merit to override the clear recognition by the Commission that as a matter of statute NEM RECs meet the requirements of sec. 399.16(b)(1)(A).

highlights how harnessing customer investment in NEM systems to meet the RPS program goals can increase the cost-effectiveness of the NEM program in harmony with statewide greenhouse gas reduction goals.

The results of TASC's Third Case clearly demonstrate that our proposed NEM successor tariff meets the requirements in AB 327 (Pubic Utilities Code §2827.1(b)(1), (3), (4), and (5)). The results of the Total Resource Cost (TRC) Test and the Societal Test are greater than 1.0 which indicates that our proposed NEM successor tariff can meet the statutory requirement in §2827.1(b)(4) that the total benefits and costs to "all customers and the electrical system" are approximately equal. Moreover, the results of the Participant Cost Test are also greater than 1.0 indicating that participant economics are favorable which meets the requirement §2827.1(b)(3). Our modeling also shows that approximately 8 gigawatts of customer-sited DG is estimated to be installed under our NEM successor tariff which is on the lower end of the level of installations necessary for a sustainable market as required by §2827.1(b)(1). These results bolster the notion that the Commission should stay the course on NEM as there is no compelling reason to sharply diverge from NEM based on the results of the Public Tool. This point is particularly important as the Public Tool does not model the disruptive impacts that a regime change would have on the customer-sited DG market.

While not required by §2827.1(b) and not utilized by the Commission as the basis for approving any other demand-side management programs, TASC also reviewed the impacts of maintaining NEM on utility revenue requirements and on non-participating customers. TASC modeling results show that recent changes to rates adopted in R.12-06-013 will significantly reduce impacts to non-participating customers when compared to prior Commission studies and the RIM test results are well within the range of RIM test results for other Commission demand-side management programs the Commission has approved. With the comprehensive suite of programs adopted or under development at the Commission, nearly all utility customers will have opportunities to invest in renewable DG resources either on-site or via programs such as the green-tariff shared renewable program. The best way to ensure all customers have access to a sustainable customer-sited DG market is to continue utilizing the policy that has been proven to work – net energy metering.

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PROPOSAL FOR AB 327 SUCCESSOR TARIFF OF THE ALLIANCE FOR SOLAR CHOICE

Pursuant to the schedule established in *Assigned Commissioner's Ruling Granting in Part Motion of The Alliance for Solar Choice and Revising Procedural Schedule*, The Alliance for Solar Choice ("TASC") respectfully submits the following Proposal for AB 327 Successor Tariff/Contract. In accord with the Administrative Law Judge's Ruling…Seeking Party Proposals for the Successor Tariff or Contract…filed June 4, 2015,[3] TASC has included an executive summary of our proposal in the initial pages of this pleading and has followed the guidelines for organizing our proposal as requested.[4] We have also included our justification for how our proposal and modeling differ from the analysis presented in the Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract (Staff Tariff Report)[5] that was brought into the record by prior ruling. The input assumptions for our Public Tool runs and the full Public Tool that we utilized are available for any interested party to utilize.[6] Finally, we

[3] Herein after June 4 Ruling.
[4] See June 4 Ruling at pp. 3-12.
[5] Administrative Law Judge's Ruling (June 4, 2015), R.14-07-002, Attachment 1, Staff Paper on the AB 327 Successor Tariff or Standard Contract [hereinafter Staff Tariff Report] (June 3, 2015), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K410/152410786.PDF.
[6] Use cases are available at: https://www.dropbox.com/sh/22dmtoiqh5vqfvn/AAAkrZ3eU99NOcY2U6fcoe5ga?dl=0

have demonstrated below how our proposal meets the statutory criteria established by Public Utilities Code Sections 2827.1(b)(1), (3), (4) and (5).[7]

The Alliance for Solar Choice leads advocacy across the country for the rooftop solar industry. Founded by the largest rooftop companies in the nation, TASC represents the vast majority of the rooftop solar market and has been an active participant in numerous Commission dockets addressing the continued evolution and growth of California's solar PV market. Its members include: Demeter Power; Silevo; SolarCity; Solar Universe; Sunrun; Verengo; and ZEP Solar. These companies are responsible for more than 100,000 solar installations serving businesses, residents, schools, churches and government facilities across the United States.

I. Introduction

The Alliance for Solar Choice supports the Commission's effort via this docket to develop a successor tariff/contract to California's current net energy metering ("NEM") tariff in order to support continued, sustained growth in customer-sited renewable distributed generation (DG) in a way that is fair and equitable to all of California's energy stakeholders as required by AB 327. Net metering, meter aggregation, third party ownership models, and other policies have been instrumental in removing regulatory and market barriers to customer adoption of renewable DG. As of the end of 2014, nearly 55,000 Californians were employed in the solar energy sector, making this sector one of the most dynamic in the state with total employment higher than all three of the major investor-owned utilities combined.[8] Rooftop solar has become an increasingly important energy management tool that has enabled tens of thousands of California households and businesses to reduce their energy costs, saving them tens of millions of dollars. Furthermore,

[7] *See* June 4 Ruling at pp. 3-4.
[8] The Solar Foundation, California Solar Jobs Census 2014 (2015) 8, http://www.thesolarfoundation.org/wp-content/uploads/2015/02/California-Solar-Jobs-Census-2014.pdf.

as among the most visible forms of clean energy, rooftop solar play an important role in educating customers about the opportunity to pursue clean energy solutions that are good for the state's environment and customer pocketbooks. Net metering, and the solar market that it has played a pivotal part in enabling, is widely recognized as a foundational policy that has underpinned California's ambitious efforts to address climate change.

The analysis put forward in this proposal demonstrates the importance of carrying forward the existing NEM framework largely unchanged except for NEM participants under the successor tariff/contract beginning to pay public purpose program charges after a phase in period. Continuation of NEM in much the same form as it is currently implemented will prevent cost and market uncertainty while capitalizing on NEM's simplicity to customers to ensure continued adoption of DG. NEM produces significant system benefits, consistent with Public Utilities Code 2827.1[9] and other state and federal law. Accordingly, proposals to vary California's successful net metering program bear a heavy burden of demonstrating not only compliance with the law, but also that they would do a better job at supporting customer-sited DG and the burgeoning industry the state has cultivated through sustained and consistent policy action.

Historic Federal and State Policy Has Been to Foster Alternative Energy Growth and Energy Market Competition

The enactment of the Public Utilities Regulatory Policy Act of 1978 ("PURPA") is generally accepted to be one of several pivotal moments in the evolution of the alternative energy industry, and the electricity industry as a whole. PURPA opened the nation's energy markets by creating a series of rights for certain "qualifying facilities," among these the right to

[9] All references hereinafter are to the California Public Utilities Code unless otherwise stated.

connect to the electric grid of a public utility;[10] the right to buy electricity and capacity from, and to sell electricity and capacity to, a public utility;[11] and to be protected from discriminatory practices that might inhibit the exercise of these rights.[12] PURPA's legacy has been to level the playing field for energy resources such as DG, creating a more robust market by allowing alternative energy facilities the opportunity to compete with traditional generation.

California has a long history of building on the foundation provided by PURPA. By virtue of these efforts, it has established itself as a national leader in DG policy —and customer-sited solar DG in particular. Among California's efforts are the state net metering law in 1996, the creation of the Emerging Renewables Program, which began in 1998, creation of the Self Generation Incentive Program, and the establishment of the California Solar Initiative ("CSI") in 2007. California's customer-sited solar DG initiatives have evolved significantly over time to offer greater opportunities in general for solar DG customers, and to address unique barriers faced by certain customer segments. The net metering law, which by our count has been amended more than 15 times since its original adoption, is a prime example of this continued, concerted effort. These changes have included several increases to the aggregate net metering cap, as well as the establishment of the virtual net metering ("VNM") and net metering aggregation ("NMA") policies. These policies have evolved to address unique barriers faced by certain customer segments, such as renters in multifamily housing, promoting the idea that solar is for everyone.

[10] 18 CFR 292.303(c).
[11] 18 CFR 292.303(a)-(b); 18 CFR 292.304(d).
[12] 18 CFR 292.304(a)(ii); 18 CFR 292.305(a)(ii).

Market Transformation is the Guiding Concept Behind California's Solar DG Policies and Programs

Underpinning all of these advances has been the idea of "market transformation," the use of strategic market intervention to remove barriers to policy goals. Market transformation represents an overarching vision for the future and a guiding principle for the state's policy actions related to customer-sited DG. Nowhere is this clearer than in the design of the CSI program, where the initiating legislation declared that "[i]t is the goal of the state . . . to establish a self-sufficient solar industry in which solar energy systems are a viable mainstream option for both homes and businesses."[13] As the Commission aptly stated in its 2006 decision adopting the preliminary structure of the CSI:

> "Through the CSI, the Commission and CEC endeavor to *transform the existing energy market* to make solar products cost-effective, with the goal of eliminating the need for incentive payments after 2016." [emphasis added][14]

Indeed, since its inception, CSI "has overcome the market barriers the program planners sought to address," and it has been credited both with "'getting the market started'" and driving a foundation for a robust and sustainable future market.[15] The CSI has met this goal ahead of schedule in the largest, general market segment, and the state continues to address the cost barriers for unique customer segments through the extension of the respective Single-Family

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[13] *See* Senate Bill (SB) 1 (Murray, Chapter 132, Statutes of 2006) and Public Resources Code (PRC) 25780, p. 5. Available at: http://www.energy.ca.gov/2009-SOPR-1/documents/sb_1_bill_20060821_chaptered.pdf

[14] D.06-08-028 at pg. 8.

[15] Navigant Consulting, California Solar Initiative Market Transformation Study (Task 2) (2014) x-xii, http://www.cpuc.ca.gov/NR/rdonlyres/C0AC3B34-2321-49FC-8351-963B290E943E/0/CSIMTStudyTask2ReportFinalFinalCLN20140425.pdf.

Affordable Solar Homes ("SASH") and Multi-Family Affordable Solar Housing ("MASH") programs.[16]

In these and other policy advances, California utilities have taken the role of facilitators in the long-lived process of market transformation. They have opened interconnection policies and procedures, processed net metering applications, created greater customer solar financing options, and provided incentives, under the direction of state policy, the Commission, and customer demand. The Commission articulated this vision of utilities as the facilitators of ever-increasing levels of distributed generation in its directive requiring utilities to develop distribution resource plans, noting that "the Commission, the IOUs, consumers and new service providers, must work cooperatively . . . to promote DER [distributed energy resources] in locations that will provide the greatest net benefits to the grid."[17] The Commission has even gone so far as to acknowledge that in the long-term, the level of distributed generation it envisions "may well trigger necessary changes to business models and utility service platforms."[18] In a recently published white paper, the Commission's Policy and Planning Division considered how the Commission's recent activities will foster a marketplace in which DERs can compete with traditional resources, ultimately creating shifts in the traditional utility business model. [19] Changes to utility business models can thus be seen as a logical extension of past and ongoing market transformation efforts.

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[16] Tim Drew et al., California Public Utilities Commission, California Solar Initiative Annual Program Assessment (2014) 32-38, http://www.cpuc.ca.gov/NR/rdonlyres/9FBE11AB-1120-4BE1-8C66-8C239E36A641/0/CASolarInitiativeReport2014_0701.pdf; Cite to general finding of CSI Market Transformation Study that MT is occurring and persisting. 2013 AB 217 (http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB217)

[17] R. 14-08-013. Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 - Distribution Resource Planning at 4. February 6, 2015.

[18] *Id*. at 5.

[19] California Public Utilities Commission, Policy and Planning Division.

But this role for utilities would not be possible without the role of the customer shifting as well, from passive consumer to active generator and manager of electricity. The state's market transformation policies are converting customers—and by extension, the businesses that serve their needs in the competitive market—into critical actors. In 2013, the Commission's Policy and Planning Division staff identified the role of customer participation as critical to meeting the state's renewable DG deployment goals, and its broader efforts to reduce greenhouse gas emissions, stating:

> Customer participation, more than the actions of the utilities or of the regulators, is critical to meet California's greenhouse gas emission goals in a cost-effective manner… they [customers] have become an integral part of the power supply chain and of the grid itself. This is a paradigm shift from the historical view of utility consumers as merely ratepayers and passive recipients of electricity services to active participants in the power grid. In fact, this energy future represents a fundamental change in the relationship between the utility and the customer, increasing the onus on both to become partners.[20]

This is precisely the trajectory that California has set for on-site solar deployment, utilizing incentives, net metering and other policy tools to enable customers who wish to serve their energy needs with customer-sited distributed generation to do so. Utilities are partners in this progression, but they are not the drivers of solar DG deployment and do not hold the keys to unlocking its full potential.

Electric Utility Business and Regulatory Models. June 8, 2015.

[20] California Public Utilities Commission, Policy and Planning Division. Customers as Grid Participants: A Fundamentally New Role for Customers. May 15, 2013. Pg. 3.

Net Metering Sits at the Core of California's Market Transformation Efforts

It is important to acknowledge the variety of policy innovations that have made California a leader in solar DG.[21] That said, in understanding how far the state has progressed in its market transformation vision, the importance of a single policy, net metering, cannot be overstated.[22] Net metering has endured while other programs like the ERP and some segments of the CSI came and went, and it has been critical to their success. The reasons for net metering's success are manifold, including the following:

1. Net metering is simple and easily understood by customers. It requires a single meter, often visualized as rolling backward when the sun shines. This simplicity makes it easy for providers to explain and average customers (who may only spend minutes per year looking at their electric bill[23]) to understand. While rarely accomplished in the energy industry, practitioners often strive for simplicity: "the related 'practical' attributes of simplicity, understandability, public acceptability, and feasibility of application" are among the criteria James C. Bonbright listed as key to developing a desirable rate structure.[24]

2. Although net metering laws can vary from state to state, the fundamental concept has been adopted by 44 states and the District of Columbia.[25] Even as solar policy can vary dramatically across states, net metering—particularly at the residential level—is a near constant.[26] This geographic consistency creates a foundation that allows multi-state providers to use common business models across states, creating economies of scale that continue to drive prices down for customers. Market consistency of the kind that net metering achieves in practice is sought by other policy efforts, including the Department of Energy SunShot Initiative,

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[21] Appendix B to CSI Market Transformation Study, http://www.cpuc.ca.gov/NR/rdonlyres/EEE23604-D584-4D18-8142-1B2F7EA5788E/0/CSIMTStudyTask2ReportAPPENDICESFinalFinal20140425.pdf.
[22] Navigant Consulting, California Solar Initiative Market Transformation Study (Task 2) (2014) 13, http://www.cpuc.ca.gov/NR/rdonlyres/C0AC3B34-2321-49FC-8351-963B290E943E/0/CSIMTStudyTask2ReportFinalFinalCLN20140425.pdf (calling NEM "instrumental in helping to drive the market for distributed solar PV in California").
[23] Accenture The New Energy Consumer Handbook (2013) 107, https://www.accenture.com/us-en/~/media/Accenture/Conversion-Assets/DotCom/Documents/Global/PDF/Industries_9/Accenture-New-Energy-Consumer-Handbook-2013.pdf (noting that the average consumer interacts with their electric provider an average of 9 minutes per year).
[24] James C. Bonbright, Principles of Public Utility Rates (1961) 291.
[25] *See* Freeing the Grid 2014
[26] *See* D.14-03-041, p. 20 (discussion need for regulatory certainty).

which works to reduce solar soft costs by (among other efforts) helping communities standardize permitting fees and processes.[27]

3. Net metering has longevity—it has been a consistent part of California solar DG policy for nearly 20 years. This longevity in itself has value because market transformation, by definition, is a slow process. For instance, in adopting early policies and funding for the CSI, the Commission determined that long-term market support was necessary to develop a sustainable solar market,[28] and noted that parties emphasized the importance of long-term certainty in terms of costs and program funding.[29] Long-term consistency is critical in allowing markets to evolve and mature, and California's solar DG market has evolved with net metering as the foundation.

Changing the framework of net metering, and therefore the benefits it provides, could disrupt functioning markets. Potential alternatives to net metering have not caught traction in part for this reason. For example, the Value of Solar Tariff methodology ("VOST") can create uncertainty for customers and investors by changing the price paid to customers under long-term solar contracts on an annual basis.[30] Currently, a VOST has only been deployed by one utility, Austin Energy, and has yet to be implemented by any state.[31] In the same vein, modifications to existing DG policies, and implementation of new ones, can have unintended consequences. For example, the City of Gainesville's feed-in tariff ("FIT") program stimulated the installation of a significant amount of distributed solar, but had to be shut down in 2013 due to implementation

[27] *See, e.g.,* U.S. Department of Energy Solar Energy Technologies Office SunShot Initiative, Tackling Challenges in Solar: 2014 Portfolio (2014) 96, http://energy.gov/sites/prod/files/2014/08/f18/2014_SunShot_Initiative_Portfolio8.13.14.pdf.
[28] D.06-01-025 at p. 5.
[29] D.06-01-025, Appendix A at p. 1.
[30] Mike Taylor et al., National Renewable Energy Laboratory, NREL/TP-6A20-62361, Value of Solar: Program Design and Implementation Considerations (2015) 44, http://www.nrel.gov/docs/fy15osti/62361.pdf.
[31] The state of Minnesota adopted a methodology for determining a VOST rate in 2014, but none of the state's utilities have elected to seek approval to offer the VOST to customers with onsite generation.

practices that, among other problems, included loopholes that allowed for contract speculation.[32] Both of these policies risk state and federal tax consequences for customers,[33] who may not understand those consequences in advance or may be deterred by concerns regarding their complexity. The importance of simplicity to the typical customer is underscored through the example of Vermont, where the deployment of customer-sited solar under a FIT has been spotty at best for small, customer-sited facilities. Vermont's Sustainably Priced Energy Enterprise Development ("SPEED") program offered standard, fixed-price contracts for solar and other renewable resources from 2009 to early 2013. The 36 solar projects that obtained contracts under this program and a competitively bid successor total of roughly 58 MW in generating capacity, yet only 10 of these projects are sized at 1 MW or less and only 6 are sized at 50 kW or less.[34] By way of comparison, the Vermont Public Service Department reports that as of September 2014, the state had more than 4,000 solar net metering customers totaling almost 60 MW (approximately 5.8% statewide peak demand).[35]

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[32] *See generally* Harvard Kennedy School Case Number 1963.0, Gainesville Regional Utilities' Feed-in Tariff (2012), http://web.mit.edu/lstokes/www/docs/Stokes&Lee_2012_Gainesville_FIT_case.pdf.

[33] *See*, *e.g.*, Arizona Corporation Commission Docket No. E-01345A-13-0248, Public Comment Letter of the Alliance for Solar Choice re Application of Arizona Public Service Company for Approval of Net Metering Cost Shift Solutions (Aug. 15, 2013) (filing a legal memorandum from Skadden, Arps, Slate, Meagher & Flom LLP, explaining that payments received by taxpayers for sale of electricity under feed-in tariffs likely fall within the definition of taxable gross income); Hawai'i Public Utilities Commission Docket No. 2014-0192, Hawai'i Solar Energy Association's, Hawai'i PV Coalition's, Hawai'i Renewable Energy Alliance's, Ron Hooson's, Life of the Land's, Sunpower's and the Alliance for Solar Choice's Final Statement of Position (2015) (filing a legal memorandum from Chun Kerr LLP explaining that feed-in tariff payments would likely be considered gross income).

[34] The majority of projects are sized at or near the maximum system size cap of 2.2 MW. See VermontSPEED. *Projects with Contracts*. April 25, 2015. http://vermontspeed.com/standard-offer-program/

[35] Vermont Public Service Department. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*. October 1, 2014. http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf

Stated simply, net metering is a known quantity, supported by decades of consumer and industry experience that have resolved the various historic regulatory and legal issues. In contrast, far greater unknowns exist for the potential alternatives, both in a legal sense, and in the level of attractiveness to potential solar DG customers. As of the end of 2013, the U.S. EIA reports that more than 470,000 customers had installed net-metered solar installations.[36] Clearly, net metering has proven to by and large be more attractive to state policymakers and customers than alternative models. The design that TASC proposes accomplished this by retaining the basic framework of net metering, with adjustments to address the parameters outlined in AB 327.

Standard NEM Successor Tariff/Contract

A. **Linking Public Tool Results to Statutory Criteria Set Forth in Section 2827.1 Sustainable Growth - 2827.1(b)(1)**

Section 2827.1(b)(1) requires the successor tariff/contract developed by the Commission ensure that "customer-sited renewable generation continues to grow sustainably . . ." Continued, sustained growth in customer-sited DG is best achieved by preserving and fostering market conditions that ensure that customers continue to adopt customer-sited renewable DG at a rate of adoption and under customer terms that are sufficient to support multi-year industry investment and expansion. As participants in this docket have recognized, adoption rates for new technologies follow predictable patterns that contemplate continuation of robust growth rates in the near term with growth slowing as the market for customer-sited DG matures. This view of technology adoption rates is well understood and already embedded in the Public Tool. As Energy and Environmental Economics ("E3") explained in the December 2, 2014 workshop on

[36] U.S. Energy Information Administration. Form 861. Net Metering 2013. February 19, 2015. http://www.eia.gov/electricity/data/eia861/index.html.

the Public Tool, the adoption rate component of the Public Tool will have the graphical shape of an "S-curve." Therefore, the near-term goal for installations should be for year-over-year growth in solar MWs installed to exceed the MW growth in the prior year to match the appropriate slope of the adoption curve.[37] As Solar Parties discussed in our prior comments, our criteria for sustainable growth does not envision year-over-year growth increasing in perpetuity.[38] Staff implicitly recognized that there is a minimum level of solar DG adoption that is necessary to maintain a vibrant and viable solar industry in California in "preserving and fostering sufficient market conditions to facilitate robust adoption" in the Staff Tariff Report.[39] TASC appreciates Staff recognizing this core concept and utilizing it in developing the Staff Tariff Report.

Standard Contract/Tariff "based on the costs and benefits of the renewable electrical generation facility" – 2827.1(b)(3)

Section 2827.1(b)(3) requires the successor tariff/contract be "based on the costs and benefits of the renewable electrical generation facility," which the Joint Solar Parties showed in our March comments can be accomplished with the Participant Cost Test ("PCT").[40] The PCT measures the costs and benefits of a DG technology to the customers who adopt it. The test compares DG customers' bill savings and tax benefits against their cost to install, operate, and maintain DG systems. In this way, the PCT ensures the successor tariff/contract is considered from the perspective of the customer choosing to make the investment in renewable DG. The successor tariff/contract will therefore need to pass the PCT if DG is to continue to grow sustainably by attracting customers who will realize an economic benefit from their participation.

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[37] Joint Solar Parties March 16 Comments at p. 6.
[38] Joint Solar Parties March 16 Comments at p. 8.
[39] *See* Joint Solar Parties March 16 Comments at pp. 13-14; *See also* Staff Tariff Report at pp. 1-8.
[40] *See* Joint Solar Parties March 16 Comments at pp. 13-14, 26; *See also* IREC March 16 Comments at p. 9.

The PCT was utilized to model adoption of NEM-enabled DG consistent with the requirements of Section 2827.1(b)(3).

"Total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs" – 2827.1(b)(4)

Section 2827.1(b)(4) specifically directs the Commission to balance the total benefits and costs of the successor tariff/contract "to all customers and the electrical system." The Total Resource Cost Test (TRC Test) is the SPM analysis that directly compares the benefits and costs of a DG resource for all ratepayers.[41] In the TRC Test, the costs are the capital and O&M costs of the DG resource, which are the costs to the electrical system as a whole to install, operate, and maintain the DG facility. The benefits in the TRC Test are principally the utility's avoided costs, which the utility will not have to incur as a result of the output of the new resource, plus any federal tax benefits that will accrue to California from the general body of U.S. taxpayers. If these costs and benefits are roughly equivalent, the DG resource is a cost-effective addition for all ratepayers and for the electrical system as a whole. The TRC Test is the principal perspective that the Commission considers in reviewing the cost effectiveness of energy efficiency and demand response programs. The Commission's last review of cost-effectiveness tests for DG, D.09-08-026, also emphasized the importance of the TRC Test and the desirability of mirroring the tests used to evaluate energy efficiency programs.[42]

In order to fully capture the total costs and total benefits to all customers and the electric system as a whole, the benefits and costs considered in the TRC Test should be supplemented

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[41] *California Standard Practice Manual* at p. 18.
[42] D. 09-08-026, at pp. 28-29 ("[W]e agree with the parties that have suggested our analysis of DG should mirror the cost-effectiveness analysis we currently perform for energy efficiency programs, which uses the TRC Test.").

with consideration of broader societal costs and benefits that will result from the continued development of DG resources. Analysis of a broader set of benefits accruing to society is consistent with Section 2827.1(b)(4)'s requirement that the total costs and total benefits to all customers and the electrical grid as a whole should be approximately equal. While some parties have advocated that the Commission rely exclusively on energy system benefits, this recommendation is contrary to the plain language of Section 2827.1(b)(4) and it also is too narrow of a perspective to take when evaluating the reasonableness of clean energy programs, which are specifically intended to address broader societal issues. The Commission has a long history of taking this view and has worked to develop a set of cost effectiveness tools for use in evaluating distributed generation in a framework consistent with the Commission's evaluation of other distributed energy resource (DER) programs. In fact, the Commission has repeatedly said it intends to establish a standard framework for assessing cost effectiveness of DSM resources. For instance, in 2004 the Commission stated, "In future iterations of our proceedings addressing efficiency, demand response, and electrical storage . . . we will introduce the concept of DER and seek to develop and employ a uniform cost-benefit test in judging the suitability of these options for utility planning and procurement."[43] Additionally, in workshops held in the Commission's recently established Rulemaking to develop "a regulatory framework to provide policy consistency for the direction and review of demand-side resource programs,"[44] parties

[43] Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources, R.04-03-017 (Mar. 18, 2004) at pp. 4-5; *See also* D.09-08-027 at p. 26 ("In the long term, we need an improved cost effectiveness methodology that will be implemented consistently by all three utilities in order to accurately measure, compare, and choose among existing and proposed demand response activities.").
[44] Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-side Resource Programs, R.14-10-003 (Oct. 8, 2014) at p. 1.

recommended making cost-effectiveness evaluations more consistent across different demand-side programs.[45]

The investor-owned utilities take a similar view in evaluating the propriety of their own programs. For example, in their recent applications seeking authorization to invest in electric vehicle (EV) charging infrastructure, the utilities' justifications for their proposals rest largely on policy objectives that extend well beyond the direct energy benefits that utility ratepayers would derive from these applications were they to be approved. In explaining the overarching rationale for its $654 million application, PG&E states that it "is committed to working with the Commission to accelerate EV infrastructure deployment and customer education programs in support of the Governor's zero emission vehicle (ZEV) goals for the state, including deployment of sufficient EV infrastructure by the year 2020 to support 1 million EVs, and deployment of over 1.5 million EVs on California roads by 2025."[46] In other words, the benefits of this program are entirely at the statewide policy level (promoting the state's EV adoption goals), and do not rely on the direct energy system benefits (for example, increased electric sales) which this proposal may provide. The similar proposals from SCE and SDG&E to deploy EV charging infrastructure also point to broader state policy objectives as important factors that the Commission should recognize as it evaluates these proposals.[47]

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[45] Joint Assigned Commissioner and ALJ's Ruling Requesting Response to Questions, Attachment 1, R.14-10-003 (Apr. 15, 2015) at p. 16, 20.

[46] *See* Pacific Gas and Electric Company Electric Vehicle Infrastructure and Education Program Prepared Testimony, at pg. 1-2.

[47] *See* Prepared Testimony In Support Of Southern California Edison Company's Charge Ready Application, at pg. 1; *See also* Prepared Testimony of J.C. Martin on Behalf of San Diego Gas & Electric Company, A.14-045-014 (April 11, 2014), at pg. 29-30, and Prepared Direct Testimony of Lee Krevat on Behalf of San Diego Gas & Electric Company, A.14-04-014 (April 11, 2014), at pg. 2 and 4.

Similarly, the utilities' own General Rate Cases often utilize societal cost metrics to justify utility capital investments and operating expenditures that do not translate directly into direct benefits on customers' utility bills. For example, PG&E's 2012 Value of Service Study[48] was used in PG&E's 2012 GRC to justify the authorization of funds for reliability investments, such as FLISR. While the cost of Customer Experienced Sustained Outage (CESO) would formally be a privately incurred cost, since only customers experienced sustained outages would suffer, the FLISR investments were deemed cost effective due to their forecasted ability to reduce CESO events.

Based on this analysis, TASC believes that it is completely appropriate as a matter of policy, while also meeting the letter of Section 2827.1(b)(4), to consider broader policy goals and societal benefits when evaluating the merits of a program. Clearly, based on the rationales presented by all three utilities in their respective applications, they also agree that broader statewide policy objectives are an important consideration when evaluating the merits of clean energy programs and policies. Furthermore, because nearly all citizens of California are also utility ratepayers, a test that measures the costs and benefits to all citizens is consistent with the requirements of 2827.1(b)(4). As SDG&E stated in support of its Vehicle Grid Integration ("VGI") proposal, "Ratepayer interests are served by increased environmental benefits, GHG reductions, and increased alternative fuel use; thus the VGI Pilot Program's support of EV growth in a sustainable, grid-friendly manner serves ratepayer interests."[49]

Additionally, there are a number of benefits not modeled within the Public Tool. For example, in their Distribution Resource Plan (DRP) applications, the IOUs identify a number of

[48] *See* PG&E 2012 GRC Workpapers 15-20 through 15-103, Value of Service Study, Freeman, Sullivan & Co.

[49] *See* Prepared Direct Testimony of Lee Krevat on Behalf of San Diego Gas & Electric Company, A.14-04-014 (April 11, 2014), at p. 2.

benefits that are not captured in the Public Tool. For instance, SCE and SDG&E both identify avoided distribution voltage and power quality and avoided distribution reliability and resiliency capital and O&M expenditures as areas in which DERs can potentially add benefits if handled correctly.[50] The IOUs' DRPs have identified these new avoided cost categories for DERs and indicate they will direct DER development to circuits where they will contribute the most value. Thus, to the extent the Public Tool does not capture these values, it is underestimating the benefits of DERs. Similarly, the value to society of the data that solar developers are required to provide pursuant to D.12-11-005, as a condition of interconnection, is also not valued within the Public Tool. As noted by SolarCity in comments submitted on the Proposed Decision on data submission requirements, the requirements represent an unfunded mandate on industry, particularly as the CSI program winds down and the vast majority of projects being deployed today do so without receiving any state incentives.[51] The utilities also raised concerns regarding the costs associated with the data collection requirements. In the context of the Public Tool and the quantification of the benefits, we believe the value of this data needs to be, if not explicitly included, at a minimum acknowledged as having value to customers and to society, that, if included in the Public Tool, would result in higher benefits being attributed to NEM and the behind the meter systems it enables. Recognition of this value would be consistent with the Commission's position on the importance of providing this data. As stated in the Final Decision, "Although the Commission is concerned about raising costs, we believe that the value of reporting this information significantly outweighs the incremental cost of complying with the

[50] SCE DRP at p. 62-63; SDG&E DRP at p. 43-44.
[51] Opening Comments of SolarCity on Proposed Decision Regarding Transfer of Responsibility for Collecting Solar Statistics from the California Solar Initiative To The Net Energy Metering Interconnection Process at pg. 2.

reporting requirement, from both the utility and the applicant sides."[52] Based on SolarCity's estimate that the addition of the additional data fields would increase incremental costs between $7 and $22 per application,[53] a very simple estimate of the additional benefit would be ~$19 million to $58 million in nominal terms aggregate between 2017 and 2025 under TASC's base case scenario, where deployments within 2017 and 2025 total about 2.7 million systems. This assumes that the value provided is at least equal to the costs incurred in providing this information. Given the Commission's statements regarding how the value "significantly" outweighs this incremental cost, and this estimate does not include the value of the data that was already being provided or the cost incurred by the utilities, we believe this estimate is very conservative. The Public Tool also fails to capture a number of other significant benefits associated with the deployment of renewable energy systems, including market price response (the reduction in wholesale energy costs resulting from reduced demand for wholesale energy),[54] and fuel price hedge benefits (the reduction in a utility's, and by extension customers exposure to market swings and price spikes associated with reliance on conventional power and fuel sources).[55] DG can also provide local and state-wide economic benefits in the form of local employment and general increased economic activity which the Public Tool also does not model.

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[52] D.12-11-005, pg. 6
[53] *Id*.
[54] *See* Ohio Public Utilities Commission, "Renewable Resources and Wholesale Price Suppression."
August 2013.
http://cleanenergytransmission.org/uploads/Renewable%20Resources%20and%20Wholesale%20Price%20Suppression%20%282%29.pdf
[55] See "The Use of Solar and Wind as a Physical Hedge Against Price Variability Within a Generation Portfolio; NREL and Sandia National Laboratories; August 2013, Available at: http://www.nrel.gov/docs/fy13osti/59065.pdf.

Societal Test

The Societal Test is the variant of the TRC Test that, in addition to the costs and benefits included in the TRC test, also considers a broader range of costs and benefits that will impact society but that may not result in direct costs or benefits to customers through their utility bills. Such externalities include health benefits, employment and general economic impacts, avoided land use impacts, and the avoidance of long-term damages from climate change. The Societal Test typically uses a lower, societal discount rate that places more weight on future costs and benefits. In D.09-08-026, the Commission found value in the broader consideration of benefits in the Societal Test, and determined that both the TRC and Societal Tests will provide important information on the cost-effectiveness of DG resources to ratepayers and the state as a whole:

> The purpose of our inquiry here is to develop a model for DG programs and facilities that best reflects the value of DG to society and ratepayers. To achieve this goal, we will use both the TRC and the Societal variant to assess costs and benefits of DG to both participants and non-participants, i.e., to Californians at large.[56]

Other SPM Tests

Ratepayer Impact Measure (RIM) Test

The ratepayer impact measure RIM test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-participating ratepayers in order to recover those costs, since utility shareholders have been guaranteed cost recovery for their capital investments and operating expenses. This can present an issue of equity among ratepayers. The RIM Test is sometimes called the "no regrets" test because, if a program passes the RIM Test, then all parties will benefit from the program. However, it is a test that measures equity among groups of

[56] *Id.* at pg. 28.

ratepayers, not whether the program provides an overall net benefit as an incremental resource for all customers (which is measured by the TRC and Societal Tests). This feature can also set it at odds with how resources are evaluated for purposes of integrated resource planning. As such, the RIM Test cannot, by itself, evaluate whether the program meets the requirement of Section 2827.1(b)(4) that total benefits to all customers and the electrical system be approximately equal to total costs. The cost shift measured by the RIM Test is simply a re-allocation of historical costs that the utilities have already incurred, which include guaranteed operating income for depreciation, taxes and shareholder returns, among other line items.[57] Another critique of the RIM test is that it embeds existing cross subsidies and does not reflect cost of service.

The Staff Tariff Report uses the RIM Test – to the exclusion of the TRC and Societal tests – to evaluate compliance with Sec. 2827.1(b)(4) on the grounds that the RIM Test was used as the exclusive test in the Commission's prior NEM cost-effectiveness studies.[58] However, this approach is flawed because the earlier NEM studies predate the passage of AB 327. The RIM Test by itself is clearly unable to satisfy the mandate of Section 2827.1(b)(3) that the successor contract or tariff be "based on the costs and benefits of the renewable electrical generation facility," or the requirement of Section 2827.1(b)(4) that the Commission ensure that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs."

It is notable that in evaluating energy efficiency programs, the Commission does not require the RIM Test to be performed and does not use it to evaluate cost-effectiveness.[59]

[57] Tim Woolf et al., Regulatory Assistance Project [RAP], Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs (2012) 17, http://www.raponline.org/document/download/id/6149.
[58] Staff Tariff Report at pp. 1-10.
[59] *See* D.05-04-051, Ordering Paragraph 5; also, D. 09-08-026, at pg. 26.

Furthermore, the Commission, while determining cost-effectiveness in the solar water heating (SWH) context, expressly rejected a call by PG&E to rely solely on the RIM test, stating, "we do not find it appropriate to limit our analysis of cost-effectiveness to the RIM test. Instead, we will use a test that considers broader societal impacts of a statewide program…Ratepayers will derive benefits from pollution reduction, system stability, job growth, and SWH market transformation. Thus, we find it appropriate to use a test that considers ratepayer impacts as well as broader societal benefits."[60]

The Commission, in D.92-02-075, also called the RIM test "inappropriate as the primary indicator of DSM cost-effectiveness," and noted that, "the RIM test only looks at a portion of the total costs of DSM programs, i.e., the portion reflected in utility revenue requirements. Therefore, the RIM test does not identify least-cost resource options, from an economic efficiency perspective."[61] The Commission also noted in that decision that "because of the revenue shifting characteristics of DSM, primary reliance on the RIM test would tend to promote programs that increase (or retain) electric and gas sales. While this may result in slightly lower rates in the short to medium term, it will not reduce the cost of the supply system (and customer bills) in the longer term."[62]

The *California Standard Practice Manual* also notes the weaknesses of the RIM test, stating that RIM test results "are probably less certain than those of other tests" given the RIM test's sensitivity "to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty."[63]

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[60] D.10-01-022 at p. 14.
[61] D.92-02-075 at p. 61.
[62] D.92-02-075 at pp. 62-63.
[63] *California Standard Practice Manual* at p. 15.

Indeed, because of its myriad flaws, the national trend has been to limit how the RIM Test is used to determine whether energy efficiency measures should be offered. A 2012 study by the American Council for an Energy-Efficient Economy ("ACEEE") found that, out of the five "classic" DSM cost-effectiveness tests, 22 states consider the RIM Test as a factor and only one consider it the primary test of whether to offer energy efficiency measures.[64] Since then, commissions have shifted such that no states consider the RIM Test their primary cost-effectiveness test: Florida replaced it with the TRC, and a 2012 rules change prevents Virginia utilities from eliminating energy efficiency programs based on only one test.[65] The majority of states use the TRC as their primary cost-effectiveness test for DSM.

A contributor to this trend away from the RIM Test is that its well-documented flaws have led major energy efficiency organizations to recommend against its use. ACEEE ultimately recommended that the RIM Test not be used to determine whether energy efficiency programs or measures should be offered.[66] The Regulatory Assistance Project stated that the "RIM Test therefore should not be used in screening energy efficiency programs for cost-effectiveness."[67] The National Efficiency Screening Project, a coalition of energy efficiency experts working to improve DSM cost-effectiveness screening, recommended that the RIM Test not be used because it "focuses on the re-allocation of already sunk utility system costs" rather than testing the cost-

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[64] Martin Kushler et al., American Council for an Energy-Efficient Economy [ACEEE], Report U122, A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs (2012) 12-13, http://aceee.org/sites/default/files/publications/researchreports/u122.pdf (43 states responded to these survey questions).

[65] ACEEE, State and Local Policy Database, *Evaluation, Measurement, & Verification*, http://database.aceee.org/state/evaluation-measurement-verification (last visited July 7, 2015).

[66] Kushler et al. at 37.

[67] Tim Woolf et al., Regulatory Assistance Project [RAP], Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs (2012) 17, http://www.raponline.org/document/download/id/6149.

effectiveness of new resources.[68] The RIM Test seems only to have been resurrected recently as it is, to quote the Regulatory Assistance Project, "heavily influenced by the lost revenues to the utility," even though those lost revenues "are not a true cost to society."[69]

As TASC has previously stated, we do not oppose the use of the RIM Test as a component of the Commission's analysis of a NEM successor tariff/contract. However, the results of the RIM Test must be placed in their appropriate context just as they are during the Commission's evaluation of other DER programs. Applying the RIM Test without that context in this proceeding risks creating needless conflict. A fundamental problem with the RIM Test is that it implicitly creates and pits against each other two classes of ratepayers – participants vs. non-participants, "haves" vs. "have-nots." This divisive and cynical exercise will become unnecessary if California, the solar industry, and the Commission continue to make progress in providing all ratepayers with an equal opportunity to become participants in the solar market – through lower solar costs, widespread availability of solar financing, shared solar programs for renters or those with shaded roofs, and the solar programs for disadvantaged communities that AB 327 encourages. As discussed earlier, the California Solar Initiative has made significant strides in breaking down barriers to solar PV with the long term goal of bringing solar PV into the energy resource mainstream. Given the strong public support for solar energy, we believe that most customers want to become solar participants and not remain non-participants. The Commission's focus should be on making continued progress to bring solar to scale in California – if solar is widely available as a mainstream energy resource, then all ratepayers will have an equal chance to participate, and the RIM Test will diminish in relevance.

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[68] National Efficiency Screening Project, The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening (2014) 6, http://www.homeperformance.org/sites/default/files/nhpc_nesp-recommendations_20140816.pdf.
[69] Woolf et al. at 16.

As part of our evaluation of NEM using the RIM Test, we chose to only model exported energy as the savings to a customer due to reduction in purchases of utility-supplied energy after investing in customer-sited DG when because it is the amount of utility bill credits provided to participants under the current NEM framework and in a future successor tariff that is that is the only cost to the utility due to NEM and the future successor tariff.[70] This principle recognizes that not every kilowatt-hour that customers do not purchase from the utility is directly attributable to distributed solar, some could be due to installation of energy efficiency or lifestyle changes which result in lost sales to the utility. For example, there is a strong correlation between the installation of energy efficiency measures and rooftop solar—80 percent of surveyed participants in the California Solar Initiative had installed energy efficiency measures prior to installing solar.[71] If all reductions in purchases from the utility were counted in these scenarios as a cost of NEM, the true cost of NEM would be overstated.

B. Using the Same Bookend Input Values and Retail Rate Assumptions

TASC's Proposal

As discussed above, TASC's proposal is to maintain the status quo of net metering wherein NEM is a tariffed service based on bill credits for exported energy with a one-hour netting interval, consistent with how customers receive energy usage data. Small DEG systems

[70] See D.14-03-041, p. 3 (Under NEM, customer-generators receive a financial credit for power generated by their on-site system that is fed back into the power grid for use by other utility customers.)

[71] Ria Langheim et al., Energy Efficiency Motivations and Actions of California Solar Homeowners (2014) at p. 6, https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf (presented at the ACEEE 2014 Summer Study on Energy Efficiency in Buildings).

(less than 1 MW) would continue to be exempt from interconnection costs, whereas the installation costs of systems over 1 MW would be borne by the customer. After an appropriate phase in period, we also propose that NEM customers in effect pay for public purpose program costs on a per-kWh basis, by removing the non-bypassable public purpose program costs from the retail rate credit provided for exported power.

Bookend Case Runs

As part of the Staff Tariff Report, Energy Division created and ran the Public Tool with two "bookend cases." The High Renewable DG Case reflects Energy Division's opinion as to the state of the world where "renewable DG has a relatively high value to all customers" while the Low Renewable DG Case is where "renewable DG has a relatively high value to all customers."

For each set of bookend state-of-the-world assumptions, three residential rate options are run: two-tiered rate with a 25% differential between the first and second tier; a TOU rate with a summer peak period from 4:00 pm to 8:00 pm; and a TOU rate with a summer peak period from 2:00 pm to 8:00 pm. As noted in ALJ Simon's July 20 ruling, these options reasonably approximate the final decision in the Residential Rate OIR (D.15-07-001). The three rate options differ from the rate approved in D.15-07-001 in that the phase in of the 2-tiered rate is not modeled and the Super Energy User rate at 400% of baseline is not modeled. As reported in the July 20 ruling, making the needed changes to the Public Tool would require extensive re-programming and would prevent the proceeding from meeting its required schedule.

Because TASC's proposal is the status quo, the July 27 bookend runs conducted by the Energy Division reflect TASC's proposal. While TASC does not agree that these two cases reflect the true reasonable margins of DG potential, per ALJ Simon's June 20 ruling, they are included here.

TASC's Third Case

As provided for in ALJ Simon's June 4, 2015 ruling, TASC has prepared a "third case" of Public Tool and Revenue Requirement Model settings (TASC Proposal). As demonstrated in TASC Proposal, the Energy Division bookends do not fully encompass the full bookshelf of realistic assumption sets. With reasonable and appropriate input changes and modified assumptions, the TASC Proposal shows that DG under the status quo NEM paradigm can meet the statutory requirements in Public Utility Code Section 2827.1 and facilitate continued DG growth by more accurately reflecting DG's costs and benefits.

Given the central role that the Public Tool plays in the Commission's deliberations, it is essential that it accurately model the costs and benefits of net energy metering. E3 has developed a tool that is extremely complex. While the level of sophistication embodied by the tool is to be commended, it is also important to acknowledge that with that complexity comes a certain level of risk in the form of modeling or methodological errors that either result in an over or understatement of costs and benefits. TASC, along with other stakeholders, have spent countless hours digging into the underlying details of the model and have found a number of instances where the model's assumptions or hard-wired methodologies appear to bias the results against net energy metering, understating the benefits and overstating the costs. Before the Commission uses the results coming from the Public Tool to determine whether to modify the existing program, which has proven highly effective in driving adoption of behind the meter technologies that the state has spent years cultivating, it is of paramount importance that these errors be corrected. If the errors are not corrected, the Commission should afford reduced weight, or should allow for a wider margin of error, when considering the results of the Public Tool.

The section below describes the changes TASC made to the Public Tool and Revenue Requirement models and the rationale for those changes. As required in the Ruling, electronic copies of the TASC Proposal Public Tool and Revenue Requirement model haves been provided to Energy Division and all interested parties.[72]

Changes Made to the Public Tool

The following changes were made to the default Public Tool inputs and calculations to increase it's accuracy. These changes and further details on TASC's modeling are available in a report developed on behalf of TASC by MRW, entitled Analysis of Net-Enrgy Metering Using the Public Tool, which is attached as Appendix A.

Key Input Drivers tab:

- Transmission Avoided Costs: The Public Tool did not include a default entry for transmission avoided cost. Thus, leaving the entry as-is implies that transmission avoided costs equal zero. Instead, TASC used $87 per kW-year. This value comes from a regression of the Revenue Requirement model's bulk transmission revenue requirement against the model's CAISO peak load prior to demand response. In particular the regression formula equals: Rev Req Growth from 2012 = (CAISO Peak Load Growth from 2012 in kW) x ($86.757 per kW) - ($73.333 million).
- Marginal Avoided Subtransmission and Distribution Avoided Cost: The public tool allows users to input a multiplier on the default values for avoided distribution and subtransmission costs. However, TASC believes there is a fundamental inconsistency in

[72] Use cases are available at: https://www.dropbox.com/sh/22dmtoiqh5vqfvn/AAAkrZ3eU99NOcY2U6fcoe5ga?dl=0

how these avoided costs are being calculated across the 3 IOUs, and scaling up the default values is inadequate. Instead, as describe in more detail in Appendix A, MRW adopted the IOU's marginal distribution avoided cost that were approved or are pending approval by the Commission in each IOU's respective General Rate Case proceeding.

- Assumed Utility Rate Escalation (perceived) from 5% to 3%. TASC finds the assumption that DG customers expect future rate increases of 5% to be excessive. The rate increases within the tool itself are closer to 2.5% on average, which is roughly in line with recent historical data from the Energy Information Administration (EIA).
- Energy Avoided Cost Locational Multiplier: The Public Tools allows for a multiplier to be applied to the model's default energy avoided cost. A recent study by Kevala Analytics, an energy data analytics firm, examined the locational value of solar PV in California using geospatial mapping of PV locations and modeling the interactions on the grid.[1] Based on the Kevala analysis, MRW used a 4.8% energy avoided cost multiplier to account for the additional locational benefits of solar PV.[73]
- Distribution Capital Expense scalers: TASC set these values at 80% for PG&E and SCE and 70% for SDG&E. The 20% reductions for PG&E and SCE reflect the large emphases in utilities' GRCs on getting their respective systems up to higher levels of safety as well as replacing aging assets. For example, in its 2012 Phase I General Rate Case (GRC) Application (A. 12-11-009) PG&E stated that, "Broadly speaking, the utility industry has underinvested in our energy systems over the past 20 years, relative to demand and economic growth," and "PG&E is determined to close the energy infrastructure

[73] Kevala Whitepaper: "Geography Dependent Valuation Quantifying the bias in statewide averages in PV valuation methodologies in California. August, 2105. http://kevalaanalytics.com/

investment gap in northern and central California."[74] In its SCE 2013 GRC, SCE stated "Our request in this 2015 General Rate Case (GRC) contemplates significant investment in the electric infrastructure to replace our aging equipment and to support State energy and environmental policy objectives. The Commission has recognized the need for infrastructure investment in its decision on our 2012 GRC."[75] In the long run, TASC sees these as much needed, but shorter-term, deviations in the utilities' investment stream rather than a value to from which to simply extrapolate. One would reasonably assume that once the neglected aging infrastructure has been replaced, that catch-up investments would no long be needed. As such, TASC set the PG&E and SCE distribution ate base cost adjustment factors at 80%. The reduction for SDG&E reflects the fact that the model's values are from an unapproved application (A.14-11-003). Only very rarely, if ever, is a utility's full request granted.

- Externalities: TASC's Third Run analysis includes values for the three air emissions externalities and values for water related externalities, and reliability and land use. Inclusion of these values is in keeping with the requirements of Section 701.1(c), which states, "In calculating the cost effectiveness of energy resources, including conservation and load management options, the commission shall include, in addition to other ratepayer protection objectives, a value for any costs and benefits to the environment, including air quality."

[74] A.13-11-009, Exhibit PG&E-1, at 1-3.
[75] A.13-11-003, SCE-1, at 1.

Societal Inputs	2015 Value (2015 $)	Esc
Societal Cost of Carbon	$ 36 - market /tonne CO_2	5%
Societal Cost of PM-10	$184 /lb	2%
Societal Cost of NO_x	$ 24 /lb	2%
Water Costs	$ 0.0012/kWh Thermal Generation	2%
Reliability and Land Use	$0.0240/kWh Thermal Generation	5%

The air emissions externality values are based on a survey of studies and study summaries, including from EPRI, NREL, NYSERDA, Synapse Energy Economics, E3, and RW Beck. The full list and citations are provided in the attached Report. The water externality value is based on water consumption of a combined cycle with dry cooling at a marginal water cost equal to the cost of desalination. Details are provided in the attached report. The reliability and land use values are from the White Paper prepared by Sierra Club and CALSEIA and attached to the CALSEIA Proposal in this proceeding.

In the "Advanced Rate Inputs tab:

- TASC updated the following non-residential rates to reflect current tariffs:
  - PG&E Medium Commercial default rate set to Schedule A-10 Secondary
  - PG&E Large Commercial default rate set to Schedule E-19 Primary (non-NEM)
  - PG&E Large Commercial DER Case rate set to E-19 Primary (Option R)
  - PG&E Industrial default rate set to Schedule E-20 Primary
  - PG&E Industrial DER Case rate set to E-20 Primary (Option R)
  - PG&E Agricultural default and DER rates set to Schedule AG-4B-E Primary
  - SCE Small Commercial default rates set to Schedule TOU-GS-1

- SCE Medium Commercial default rates set to Schedule TOU-GS-3 Secondary (Option B)
- SCE Medium Commercial DER rates set to Schedule TOU-GS-3 Secondary (Option R)
- SCE Large Commercial default rates set to Schedule TOU-8 Secondary (Option B)
- SCE Large Commercial DER rates set to Schedule TOU-8 Secondary (Option R)
- SCE Industrial default rates set to Schedule TOU-8 Primary (Option B)
- SCE Industrial DER rates set to Schedule TOU-8 Primary (Option R)
- SCE Agriculture default rates set to Schedule TOU-PA-2 (Option B)
- SDG&E Small Commercial default rates set to Schedule TOU-A
- SDG&E Medium Commercial default rates set to Schedule AL-TOU Primary
- SDG&E Medium Commercial DER rates set to Schedule DG-R
- SDG&E Large Commercial default rates set to Schedule AL-TOU Primary
- SDG&E Large Commercial DER rates set to Schedule DG-R
- SDG&E Industrial default rates set to Schedule AL-TOU Primary
- SDG&E Industrial DER rates set to Schedule TOU-8 DG-R

In the "Adoption Module" tab:

- Using the Public Tool's adoption algorithm, the mix of sizes, at least for solar DG, differs greatly from the historic mix. In general, the results are weighted highly towards the largest system; in a typical model run, around two-thirds of customer adoptions are "large systems" that serve 100% of customers' loads. While this result follows the analytical approach taken—the system with the best payback dominates the adoptions—it does not match the actual historic distribution of installations. There are various reasons why a consumer might not install a system that meets 100% of his/her load, even if it is economically "the best":

1. Customers tend to be conservative. If the benefits are similar for different sized systems, then most will choose the smaller system.
2. Many customers are limited by available roof space. Some people who are counted as potential customers in the technical potential of solar do not have enough roof space to size their systems to offset their entire load.
3. Solar customers on TOU rates should not size their system to offset 100% of onsite load.
4. Minimum bills can reduce or eliminate the benefits of sizing a system beyond a certain percentage of annual consumption.

To address this issue, TASC used hard-wired changes to the adoption module to allocate the system size for solar PV based on the observed size distribution in 2012. This change is designed to produce a more realistic distribution of DG system sizes, recognizing that economics alone does not determine system sizing. This change maintains the historical system size that customers have adopted in each bin of similarly-situated customers (i.e. if a bin was "small" in 2012, it will be "small" in 2017-2025), but continues to allow the economics to determine how much of each bin's technical potential is adopted. Thus, if the economics favor large systems, the bins with large systems will fill up faster, resulting in a growing percentage adoption of large systems, but not to the degree that the Public Tool's algorithm would choose.

Changes Made to the Revenue Requirement Model

The following changes were made to the default Revenue Requirement Model inputs and calculations.

In "RR Input" tab:

- Fossil Steam Capacity Factor: TASC reduced the steam capacity factor from 10% to 5%. According to the EPA's Emissions & Generation Resource Integrated Database (eGRID), for the most recent year available, 2010, the steam generators in the CAISO control area operated at an average capacity factor of 4.6%. Given the continued retirement of steam generators in the state (particularly with the OTC units being removed from service), steam boilers will become increasingly less used. Thus, even the 5% used by TASC is its modeling may overstate the steam generator output.
- Portion of Distribution Capex [capital expenditure] Costs that are Growth Related. The model assumes that 11% of the distribution capital investment is due to system expansion, and thus potentially deferrable by reducing load. While TASC believes this ratio may be "correct," it does not follow that non-expansion distribution capital investment is unaffected by reduced load on existing circuits. DG can both defer distribution capital investment by reducing power being met by the circuit as well as potentially reducing the size of equipment being replaced.[76] Because of these factors, TASC increased the 11% of distribution capital investment that is reducible by DG to 22% (double).

[76] M.A. Cohen et al., Energy Institute at Haas, Economic Effects of Distributed PV Generation on California's Distribution System (2015) 2, http://ei.haas.berkeley.edu/research/papers/WP260.pdf (finding that for circuits where peak load or load growth is high, "the value on some circuits could be a significant fraction of the installed cost of PV").

- Generation rate base cost adjustment factors: TASC assumed generation rate base cost adjustment factors of 75% SDG&E, which reflects the fact that the SDG&E inputs were based on an application (A.14-11-003) and not an approved GRC.
- Interconnection costs: The interconnection costs provided by the three utilities differ markedly—sometimes by more than a factor of five. TASC does not find this level of variation to be reasonable. While local labor and material costs can reasonably vary across the state, the variation seen is questionable. TASC as therefore assumed SDG&E's interconnection costs for PG&E and SDG&E.
- Revenue Requirement Allocation to Customer Class: TASC uses option 3, Settlement Rate Relationships, rather than option 2, Maintaining the Current Deviations. TASC's consultant, MRW & Associates, has participated in every Phase 2 GRC since 2005. In all cases, the cost allocation was set in settlement based on black-box changes to the allocators that resulted in modest, often capped, changes to the percentage of revenue requirement borne by each class. While marginal costs were developed in the GRCs for non-allocation purposes, such as developing Economic Development Rates, they have not been directly used for cost allocation. As such, TASC finds it more reasonable to assume that the same basic allocation relationships (percentages) among the rate classes continue rather than directly tying the cost allocation to the marginal cost, be it directly by using the equal percent marginal cost (EPMC) or equal deviation from EPMC.

In the "RR Calculations" tab:

- Adjustment to the Diablo Canyon O&M. In review of the revenue requirement model, TASC found that the costs associated with the retirement of Diablo Canyon upon the expiration of its license were still incurred. When this was pointed out to E3 the error in the Diablo Canyon capital expenditure stream was corrected, but the O&M error was not. In particular, when Diablo Canyon is removed from service in 2024 (assuming retirement at the end of its license), the amount associated with the plant's O&M ($300 million) is not removed from the generation O&M. This clearly overstates the generation O&M in 2024 and beyond. The response to question 83 in the "Documentation on adjustments to the Draft Version for the Public Tool to produce the Final Version of the Public Tool (i.e., the "Q&A" document,) states "E3 did not make this adjustment because we assume that some level of O&M costs will continue after nuclear plant retirement." While it is likely true that some O&M would continue, it should be dramatically less than what is incurred for an operating plant and not extend all the way to 2050. Furthermore, post-retirement Diablo Canyon costs should be partially, if not fully, covered by the Decommissioning Trust. To correct this, TASC removed the Diablo Canyon O&M amount from PG&E's revenue requirement.

- SDG&E Generation CapEx. The Revenue Requirement model cites to a table in SDG&E's GRC filing that includes a number of factors which have to be adjusted or removed to achieve the generation capital expense value. Instead, TASC instead used $8 million, from GRC Exhibit SDG&E-11, which explicitly identifies SDG&E's generation capital expenditures.

<u>Results of TASC's Third Case</u>

The June 4 Ruling explicitly notes that any party's third case must demonstrate that it meets the statutory criteria in Section 2827.1.[77] In the March 16, 2105 Comments of the Joint Solar Parties (which included TASC), specific results metrics were identified for evaluating

[77] Administrative Law Judge's *Ruling*, R.14-07-002 (June 4, 2015) at p. 3.

NEM Successor Tariff proposals.[78] The performance of the TASC Proposal using these metrics is presented below.

With respect to the requirement for continued sustainable growth (Section 2827.1(b)(1)), the Joint Solar Parties advocated that the Successor Tariff preserve and foster market conditions that ensure that customers continue to adopt customer-sited renewable DG at a rate of adoption and under customer terms that are sufficient to support multiyear industry investment and expansion.[79] As noted in the March 16 Joint Solar Party Comments, this does not mean the continuation of the 30+% year-over-year growth seen in the 2011-2014 time frame in perpetuity, but rather that the absolute numbers of installations and capacity added should at least equal recent levels.[80]

Table 1 shows average annual growth in customer-sited DG in percent per year, MW per year and cumulative capacity in 2025 for TASC's Proposal and a range of sensitivities. For comparison purposes, TASC included the Public Tool's DG growth for 2012-2016 is included. Since the overarching statutory requirement in Sec. 2827.1(b)(1) is for continued sustained growth, the DG growth in the four modeled cases can be compared to the historic baseline. On a percentage basis the 2012-2016, the growth rate in customer-sited DG was 46% per year growth, over four times that of any of the modeled cases. However, expecting market growth to continue at a compound rate of 46% is not what solar parties have advocated in this docket. Instead, we've proposed assessing "continued sustained growth" by comparing the absolute growth in megawatts in the historic period to that in the forecast periods. When viewed from this

[78] *See* Joint Solar Parties March 16 Comments at pp. 6-10.
[79] *Id.* at p. 6.
[80] *Id.* at p. 8.

perspective, all the modeled cases are on the same order of magnitude as the megawatt growth in the historic period. Therefore, TASC's Proposal meets the continued sustainable growth criterion

Table 1. DEG Growth Statistics (2016-2025)

Case	Ave. DEG Capacity Growth, %/year	Ave. DEG Capacity Growth, MW/year	Total DEG Capacity in 2025[81], MW
TASC Proposal	11.1%	871	12,022
NBC Sensitivity	11.1%	873	12,035
$15 Min. Bill Sensitivity	10.9%	854	11,865
High Renewables	11.5%	925	12,503
2012-2016 (per Public Tool)	*46%*	*764*	*n/a*

Again as put forth in the Joint Solar Parties' March 16 Comments and discussed earlier in this Proposal, the consideration of "costs and benefits of the renewable generation facility" (Section 2871(b)(3)) is best measured using the Participant Cost Test, which measures the costs and benefits of a DG technology to the customers who adopt it.[82] Table 2 below summarizes the Participant Cost Test results from TASC Proposal using the three required residential rate designs. Table 2 clearly shows that all three cases are positive overall and is positive for both the residential and non-residential classes. It also shows that the PCT benefit cost ratios have very little divergence. Given the uncertainties in the inputs to the Public Tool, for practical purposes one should call them all equivalent. We believe this is reasonable and represents a modest payback to the customer for their investment and associated risk.

Table 2. Participant Cost Test Benefit-Cost Ratios (TASC Proposal)

Case	All Classes	Residential	Non-residential
2-Tiered	1.42	1.38	1.56
TOU narrow	1.48	1.45	1.56
TOU wide	1.42	1.37	1.56

Consistent with the March 16 Joint Solar Parties' Comments and the discussion above, with respect to the criterion that the "total benefits of the successor tariff to all customers

[81] Including capacity from grandfathered DEG.
[82] Joint Solar Parties March 16 Comments at pp. 2, 9-10, 13-14.

approximately equal the total costs" (Section 2827.1(b)(4)), TASC recommends using the Total Resource Cost Test in conjunction with the Societal Cost Test.[83] Tables 3 and 4 below show the benefit-cost ratios of the TASC Proposal under either of these tests is greater than 1.0, and therefore meets the requirement that total benefits for all customers approximately equaling the total costs.

Table 3. Total Resource Cost Test Benefit-Cost Ratio

Case	All Classes	Residential	Non-residential
TASC Proposal	1.20	1.18	1.25
With NBCs	1.20	1.19	1.23
$15 MB	1.20	1.19	1.25
High Renewables	1.47	1.45	1.45

Table 4. Societal Cost Test Benefit-Cost Ratio

Case	All Classes	Residential	Non-residential
TASC Proposal	1.51	1.49	1.57
With NBCs	1.51	1.49	1.56
$15 MB	1.51	1.50	1.58
High Renewables	1.50	1.48	1.48

Based on the results from the Total Resource Cost Test and Societal Test, TASC believes continuation of California's success NEM program without significant modification is justified. Moreover, this result is consistent with recent Commission decisions (1) approving energy efficiency programs where the overall energy efficiency portfolio's TRC test was greater than 1.0,[84] (2) approving the utilities demand response portfolios which showed a range of TRC tests results and the Commission found that particular programs with a TRC test between 1.0 and 0.9 would be considered cost effective and programs with a TRC test between 0.5 and 0.9 are "possibly cost effective" with further sensitivity analysis and most program changes to increase

[83] *See* Joint Solar Parties March 16 Comments pp. 13-14.
[84] See 14-10-046 at pg. 24 (noting the energy efficiency portfolio is designed to be cost effective as a whole), Finding of Fact no. 15 (describing the portfolios as marginally cost effective)

cost effectiveness.[85] The results presented in the tables above are well above the threshold set by the Commission for cost effectiveness and therefore NEM should continue with no alteration.

Although TASC does not recommend using the Rate Impact Measure (RIM) test as major criterion for evaluating DG, Table 5 below nonetheless shows the results of the RIM test for the TASC Proposal. For each case, two RIM benefit-cost ratios are shown: one when the impact of the reduced behind-the-meter load is included in the calculation, and one where only the value of the exported DEG energy is included. As the table shows, even under the more stringent criteria of the RIM, the TASC Proposal's RIM is equal to 1.0 for Staff's High Renewables case, with the other RIM values falling no less than 0.8 for any combination of utility and sector.

Table 5. Rate Impact Measure Test Benefit-Cost Ratio
Overall/Export Only

Case	All Classes	Residential	Non-residential
TASC Proposal	0.85/0.80	0.86/0.8	0.83
With NBCs	0.87/0.80	0.88/0.79	0.85/0.84
$15 MB	0.86/0.80	0.87/0.79	0.83/0.84
High Renewables	1.00/0.94	1.00/0.92	1.00/0.92

C. Systems Larger than One Megawatt

As we noted in our opening policy comments, Section 2827.1(b)(5) removes the current net metering program's 1 MW participation cap for projects that "do not have significant impact on the distribution system" so long as those systems are "built to the size of onsite load" and are "subject to reasonable interconnection charges established pursuant to…Rule 21 and applicable state and federal requirements."[86] As a matter of general policy, it is reasonable for these larger systems to be eligible for net metering under the same terms as smaller systems because they serve the same function as smaller systems: the provision of energy to meet on-site needs. With the change in the underlying statute, there is no longer a rational basis for subjecting them to

[85] See 12-04-045 at pp. 44-45
[86] *See* Joint Solar Parties March 16 Comments at p. 27.

different terms and conditions. Doing so would introduce an arbitrary distinction that could restrain solar deployment by large customers in conflict with the state's overall market transformation goals, and its historic policy of eliminating barriers to solar deployment across all sectors.

With respect to the requirements imposed by Section 2827.1(b)(5), these types of projects will be subject to review under Rule 21, which is a sufficient means to identify whether a given project will have a significant impact on the distribution system. Furthermore, systems larger than 1 MW are not eligible for an interconnection cost waiver under current Commission policy,[87] so the clause subjecting them to reasonable interconnection charges would also be met by this process. The customer is therefore responsible for the cost of any remedial measures needed to mitigate distribution system impacts as a condition of the interconnection. These charges are "reasonable" because they relate to the specific upgrades necessary to accommodate the interconnection. TASC was pleased to see a broad range of stakeholders agree with the basic idea contained herein that Rule 21 procedures and processes are sufficient to mitigate any significant impact to the distribution system such that systems above 1 MW that undertake necessary system upgrades should be able to participate in net metering.[88]

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[87] *See generally* R.11-09-011, Decision No. 12-09-018, Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans, Sept. 13, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.pdf.

[88] *See, e.g.*, Joint Solar Parties March 16 Comments at p. 27; IREC March 16 Comments at pp. 17-18; *See also* NRG March 16 Comments at pp. 10-12.

D. Additional Elements

Continuation and Modification to the VNM and NMA Programs

TASC proposes to continue the existing VNM and NMA programs because they are well-suited to addressing the unique barriers to customer-sited deployment experience by low-income customers, multi-family housing tenants, and agricultural customers. Continuation of these two programs is consistent with the Commission's historic policy of removing barriers to solar deployment for all sectors and being responsive to the needs of these different sectors. It is difficult to say that a market is truly being "transformed" if the policies put in place exclude or otherwise limit opportunities for large portions of ratepayers.

The VNM program was first adopted in 2008 as part of the MASH program, allowing the electricity produced by a single solar energy system to be credited to the accounts of multiple tenants at a property without the need for the system to be connected to each individual tenant's meter. This design is intended to avoid potential technical issues and possible site-specific upgrades to multi-tenant facilities which may be cost prohibitive, and therefore to expand opportunities for solar deployment and tenant benefits in multi-family housing.[89]

In 2011, the Commission elected to expand the VNM program, finding that there were "ample reasons" to allow other ratepayers on multi-tenant properties to participate in VNM, since these ratepayers also contribute funding to the MASH program.[90] In doing so, it also introduced additional flexibility into the program for MASH projects by eliminating requirement that all beneficiary accounts be served at the same service delivery point ("SDP").[91] This change contemplates the frequent scenario where tenants on a single property are served by multiple

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[89] *See* D.08-10-036, at pg. 33 and Findings of Fact nos. 7 and 10.
[90] D.11-07-031 at 16.
[91] D.11-07-031 at 13.

SDPs, allowing a single VNM system to serve more customers while retaining the character of net metering as a mechanism that supports generation on-site of a load.

However, the Commission retained this requirement for other multi-tenant properties in order to avoid delays in the VNM expansion. TASC believes that it is appropriate to eliminate the single SDP requirement for all otherwise qualifying properties so as to remove an artificial distinction that hampers solar deployment on multi-tenant properties, and to extend VNM to non-contiguous properties. These modifications are consistent with the Commission's reasoning for expanding VNM in the first place. Due to the time constraints present in the current proceeding, TASC has not made this change an element of its net metering successor tariff proposal, but instead suggests that a process for reviewing such a change be convened in early 2016.

The NMA program, which allows a single large system to serve multiple metered accounts on contiguous property controlled by a single customer, is likewise a valuable tool that enables some customers – agricultural customers in particular -- to take greater advantage of on-site solar generation. The adoption of the NMA program is yet another example of the Commission's intent to facilitate a broad transformation of the energy market through the removal of unique barriers. In this instance, the Commission found that the adoption of NMA "will improve the cost-effectiveness of NEM by enabling larger and more efficient installations with a lower cost per kWh exported, which would result in a lower cost to ratepayers."[92] TASC's proposal includes the continuation of NMA in its current form for the time being, but we also suggest that the Commission consider revisiting the NMA definition of a "contiguous property" in early 2016 to establish additional clarity on its meaning. This definition has been heavily contested in some cases, as utilities have argued that irrigation ditches are not public

[92] Resolution E-4610 at 7.

right of ways and therefore represent the boundary of a contiguous property. TASC also believes that the spirit of net metering would be better served by relaxing the contiguous property requirement itself. As with the suggested clarification outlined above, due to the time constraints of the present proceeding, we suggest that this review be undertaken in early 2016.

Treatment of Existing Exemptions for Net Metered Systems

TASC's proposal would continue the existing exemptions contained in in Section 2827(g), which prohibit the establishment of additional charges on net metering customers beyond those of non-customer generators in the same rate class. There is ample justification for the continuation of these exemptions. First, as a matter of general policy, additional charges on net metering customers would dampen customer enthusiasm for on-site generation and be counterproductive for achieving the statutory directive for sustainable growth. Second, as a matter of law, any such additional charge would be discriminatory and impermissible under PURPA unless it can be justified based on substantial evidence that an electric utility's cost to serve DG customers is substantially different from its cost to serve other customers with similar usage patterns.[93]

TASC strongly supports maintaining the exemption from standby charges. In addition to the risk that these charges will decrease the value proposition for current and potential customer-generators and thereby harm the sustainable growth of DG, these charges lack justification, particularly in the context of intermittent self-generating NEM customers. Standby charges are traditionally applied to larger self-generators, such as CHP facilities, that have the ability to produce consistent power on a 24/7 timeframe. In the event that such a facility goes offline, the

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[93] *See* 18 C.F.R. § 292.305(a) ("Rates for sales . . . shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.")

utility is faced with a substantial load to cover. This is not the case for small intermittent solar PV facilities because forced outages for small self-generators are rare with minor impacts. For instance, such outages are very unlikely to be correlated with other DG system outages. Moreover, forced outages for these facilities are unlikely to correlate with system peak, meaning the cost of backup service to DG facilities may be less than the cost of regular retail service. As a result, levying standby charges on NEM customers would be both harmful to the state's energy goals and completely unjustified.

Treatment of the Existing Interconnection Fee Waiver

TASC proposes to maintain the existing interconnection fee waiver for facilities of 1 MW or less. Currently, NEM-qualifying systems are broadly exempt from interconnection costs, including application fees, study expenses, and distribution grid upgrades.[94] Of particular importance is exempting prospective NEM customers from distribution grid upgrade costs, which would otherwise create time delays and cost uncertainties, running counter to state policy supporting distributed generation. Furthermore, a great deal of effort has been devoted to streamlining the interconnection process for smaller systems in order to allow utilities to meet the Commission's 30-day interconnection requirement. The existing waiver facilitates this streamlining, removing a step that would otherwise require further communication between the utility and the customer. Commission Staff have called the interconnection process for NEM customers "frictionless," noting that extending NEM-type interconnection processes to other types of applicants can "level the playing field between utilities and prospective project

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[94] R.11-09-011, Administrative Law Judge's Ruling Setting Schedule for Comments on Staff Reports and Scheduling Prehearing Conference, Attachment A, Staff Proposal on Cost Certainty for the Interconnection Process (July 18, 2014) 4, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M099/K767/99767928.PDF.

applicants."[95] It also recognizes the principle that with smaller systems, not all costs to upgrade the distribution grid are due solely to the next NEM customer. Maintaining this administrative efficiency will be important in achieving the goal of continued sustainable growth in DG deployment. On the balance, these benefits in fairness and ease to applicants should outweigh concerns over the small amount of resultant costs borne by other ratepayers.

E. Safety and Consumer Protection Issues

As TASC discussed in our comments in March with the Joint Solar Parties, TASC is not aware of any unique safety or consumer protection issues associated with its proposal to maintain NEM. As noted in our previous comments, safety concerns are addressed via the interconnection standards contained in California's Rule 21.[96] TASC continues to support the use of approved equipment lists maintained by the California Energy Commission as a consumer protection measure and as a means to support efficient interconnection of pre-approved equipment.[97] TASC, however, opposes any warranty requirements, as such requirements would be a harmful market intervention that would dissuade solar service providers from offering innovative product offerings and pricing. Furthermore, as Joint Solar Parties discussed in comments, the conditions that necessitated warranties under the CSI program no longer exist, as explicit incentives from the state to support customer purchases of DG have ended or are ending.[98] Furthermore, the Joint Solar Parties believe that it is critical that the Commission be able to continue to hear

[95] R.11-09-011, Administrative Law Judge's Ruling Setting Schedule for Comments on Staff Reports and Scheduling Prehearing Conference, Attachment A, Staff Proposal on Cost Certainty for the Interconnection Process (July 18, 2014) 5, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M099/K767/99767928.PDF.
[96] Joint Solar Parties March 16 Comments at pp. 36-37; Joint Solar Party March 30 Reply Comments at p. 19.
[97] *See* CSI Handbook, Section 2.2 at pp. 23-24, *available at* http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF.
[98] *See* Joint Solar Parties March 16 Comments at p. 34.

complaints against utilities for failing to perform under the NEM successor program or for disputes arising from the utility's improper accounting of credits or charges. For that reason, the Joint Solar Parties have recommended that the Commission continue to administer the program under a tariff as opposed to a standard contract. Finally, TASC believes access to consumption data is essential to empowering customers to make informed decisions and allowing service providers to tailor solutions to optimally meet customer needs. It is therefore important that the successor tariff/contract be accompanied by enforcement of clear standards regarding data availability.

F. Legal Issues

TASC is not aware of any legal issues associated with continuing to offer NEM in California as Section 2827.1(b) specifically includes consideration of continuing NEM as a successor tariff to the current NEM program. Moreover, as demonstrated in this proposal, NEM, as proposed by TASC, meets each of the statutory requirements identified in Section 2827.1(b)(2)-(5). NEM as proposed in TASC's proposal is also fully compliant with PURPA and the Federal Power Act.[99]

II. Growth in Disadvantaged Communities

As discussed in prior comments, TASC believes that development of programs to support customer adoption of distributed generation in disadvantaged communities is essential for continued, sustained growth in customer-sited distributed generation.[100] These communities often disproportionately experience the negative impacts of traditional energy sources, so empowering these communities to enjoy the benefits of customer-sited DG should be a high

[99] *See MidAmerican Energy Company*, 94 FERC ¶ 61,340 (2001).
[100] Joint Solar Parties March 16 Comments at pp. 2, 12-13.

priority. While TASC does not put forward a specific proposal to address growth of customer-sited DG within disadvantaged communities, we believe this aspect should be given specific, separate program treatment. IREC's CleanCARE program represents one possible solution to Section 2827.1(b)(1)'s requirement that specific consideration of growth of customer-sited DG in disadvantaged communities be developed as part of the successor tariff/contract.

II. Conclusion

TASC appreciates the opportunity to provide our proposal for a NEM-based successor tariff in compliance with Section 2827.1, which will allow for the continued sustained growth in customer-sited distributed generation in California. As demonstrated in this Proposal, NEM is cost-effective in its present form and should be continued without significant modification. TASC stands ready to present the substance of this Proposal via testimony should the Commission determine hearings are necessary.

Respectfully submitted this August 3, 2015 at San Francisco, California.

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APPENDIX A

Analysis of Net- Energy Metering

Using the Public Tool

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August 3, 2015

Contents

EXECUTIVE SUMMARY

California's net energy metering (NEM) program is a billing mechanism designed to facilitate the installation of customer-side distributed renewable energy generation (DEG). Under NEM, customer-generators receive a full retail-rate bill credit for power generated by their on-site system that is fed back into the power grid during times when generation exceeds onsite energy demand.

In October 2013, Assembly Bill (AB) 327 was enacted, which, among other things, ordered the California Public Utilities Commission (CPUC or Commission) to adopt a successor to the existing NEM tariffs. Part of the legislative direction was that the NEM successor tariff should (a) allow customer DEG to continue to grow sustainably; (b) that the tariff be based on the costs and benefits of the DEG; and (c) that the benefits of the successor tariff to all customers approximately equal the costs. Part of the CPUC's response to this directive was to develop "a tool for estimating the costs and benefits of various NEM successor tariff options or rate scenarios (known as the Public Tool)."[1]

The Public Tool

The Public Tool breaks new ground for analyzing distributed energy generation. It provides immense flexibility by allowing users to input different DEG characteristics, retail rates, rate structures, avoided costs, certain revenue requirement parameters, and discount rates to name but a few. It allows for feedback between the impacts of DEG on both avoided costs and rates. These features allow policy makers in California to better understand the trade-offs and impacts of more and different policy levers than any prior tool.

The drawbacks of the comprehensive approach taken by the Public Tool, however, have been keenly felt. Because of its complexity, the model was more than two months late in being delivered to the parties in the proceeding. Three iterations, including two "final" versions have been issued. Even then, as described below, problems have been identified. The Public Tool requires over 4 hours to execute one run, greatly limiting the users' ability to conduct sensitivity analysis.

MRW's greatest concern with the Public Tool is the large amount of "default" data it contains and the ability of users to understand that data. Because it so large and complex, the less skilled user can easily place more confidence in the results than is warranted. Much of the default data are based on the model designers' judgment for values that other knowledgeable parties can—and do—find to be suspect.

[1] Order Instituting Rulemaking 14-07-002, page 10. July 10, 2014.

This leads to two fundamental concerns: opacity and false precision. For parties and individuals experienced in DEG technologies, California energy policy, and CPUC ratemaking, there areas of the model that simply cannot be vetted or verified. Less experienced parties may unwittingly come to believe that because the model is big and complex and appears to be comprehensive, the results it provides must be right. But those results are built upon a foundation of assumptions, which are subject to both uncertainty and the judgment of those who entered the assumptions.

Of equal concern is the fact that some key variables are not obvious. For example, the selection of which rate allocation method is used, a selection that is made hundreds of rows down in a sheet in the Revenue Requirement Model, can have a profound effect on the results, making a successor tariff cost-effective, or not, depending upon the user's selection.

This is not to detract from the value that the Public Tool can provide in analyzing DEG policy. It is a very impressive tool. Rather, it is to place its use and usefulness in perspective. Policymakers and analysts can be tempted to rely upon models such as the Public Tool because they generate very specific and precise answers: "This is what the model says." However all models are only as accurate as their data and the reasonableness of the methodologies they deploy. Model outcomes based on uncertain inputs and methodologies are uncertain, even if the results are shown to four decimal places.

NEM Analysis with the Public Tool

The Alliance for Solar Choice (TASC) retained MRW & Associates, LLC to assist TASC by providing recommendations and feedback to the Energy Division during the development of the Public Tool, review the tool when it is released, and provide analysis and comments on the tool's accuracy and usefulness in evaluating successor NEM tariffs.

To that end, MRW reviewed the Public Tools input and calculations, made corrections and updated input variables based on its experience in California energy policy, and analyzed net energy metering using the updated Pubic Tool. The changes included adjusting the algorithm that "chooses" which size of DEG technologies to implement, adjustments to the revenue requirement model to better reflect ratemaking in California, and included values for specific environmental externalities that can be avoided through the use of DEG.

MRW analyzed a number of cases using the Public Tool: the TASC Proposal (broadly, *status* *quo* NEM)[2]; sensitivities around the TASC Proposal to see the impact of differing residential rate designs such as fixed charges and minimum bills; and a case that assumes an aggressive renewable policy: 50% renewable portfolio standard (RPS) requirements, no renewable curtailment, and the allowance of DEG renewable output to be counted towards the host utility's RPS requirement. These cases are shown I Table ES-1.

Table ES-1. Public Tool Scenarios

Case	DEG pays NBCs	RPS Requirement	DEG REC Treatment	Residential Minimum Bill	Residential Fixed Charge	Residential Rate
TASC Case		33%	Default	$10		2-tier
TASC Case		33%	Default	$10		Narrow TOU
TASC Case		33%	Default	$10		Wide TOU
NBC Sens.	✓	33%	Default	$10		2-tier
MB Sens.		33%	Default	$15		2-tier
FC Sens.		33%	Default		$10	2-tier
High RPS		50%	Bucket 1			2-tier

As noted, continued and sustainable growth in renewables is a key metric. Table ES-2 below shows annual average growth in DEG capacity in megawatts and percent, along with the 2025 total renewable DEG capacity added. For comparison purposes, the Public Tool's DEG growth for 2012-2016 is included. Since the statutory requirement is for continued sustained growth, the DEG growth in the four modeled cases can be compared to this historic baseline. At 46% per year growth, on a percentage basis the 2012-2016 growth rate is over four times that of any of the modeled cases. However, expecting market growth to continue at a compound rate of 46% is clearly not reasonable. Thus, to assess the "continued sustained growth" criterion, one can compare the absolute growth in megawatts in the historic period to that in the forecast periods. When viewed from this perspective, all the modeled cases are on the same order of magnitude as the megawatt growth in the historic period. As such, these NEM policies can reasonably be assumed to pass the continued sustainable growth criterion.

[2] TASC's Proposal differs from the status quo by having customer-sited DEG users pay the Public Purpose Program charge based on their gross consumption. Because the non-bypassable functions in the Public Tool do not allow for treating PPP independently of other non-bypassables, the TASC Proposal results will fall between the "TASC Case" and the "NBC Case." As will be shown, the TASC Case with and without the full NBC payments are nearly identical, the actual TASC Proposal can be modeled as NEM either with or without NBCs.

Table ES-2. DEG Growth Statistics (2016-2025)

Case	Ave. DEG Capacity Growth, %/year	Ave. DEG Capacity Growth, MW/year	Total DEG Capacity in 2025[3], MW
TASC Case	11.1%	871	12,022
NBC Case	11.1%	873	12,035
$15 Min. Bill Sensitivity	10.9%	754	11,865
High Renewables	11.5%	925	12,503
2012-2016 (per Public Tool)	*46%*	*764*	*n/a*

MRW believes the benefit-cost metrics that reflect the legislatively-mandated cost effectiveness criteria are the Participant Cost Test (PCT), the Total Resource Cost Test (TRC), and the Societal Cost Test (SCT). With respect to the PCT, all of the scenarios that MRW showed benefit-cost ratios on the order of 1.3 to 1.6. This makes sense, as DEG would not continue to grow if it were not cost beneficial from the user's perspective.

Table ES-3 shows the benefit-cost ratios according to the TRC and SCT tests for the TASC Proposal and the High Renewables case. (The TRC and SCT results for the differing residential rate designs did not meaningfully differ from the TASC proposal.) The TRC benefit-cost ratio for the High Renewables case is significantly greater than the cases based on the TASC Proposal. This savings is caused at least in part by the Bucket 1 treatment of the DEG RECs: with DEG being able to fully offset utility-scale renewables, each kWh of DEG generation is can now avoid significantly more costs than they could without Bucket 1 treatment. The assumption of no renewable curtailment also contributes, as "free" (i.e., no variable cost) energy does not have to be forgone for grid management purposes.

Table ES-3. Benefit-Cost Ratios

Case	All Classes	Residential	Non-residential
Total Resource Cost Test			
TASC Proposal	1.20	1.18	1.25
High Renewables	1.47	1.45	1.45
Societal Cost Test			
TASC Proposal	1.51	1.49	1.57
High Renewables	1.50	1.48	1.48

[3] Including capacity from grandfathered DEG.

The difference in the SCT benefit-cost ratio between the TASC Proposal and the High Renewables case is minimal. This is due to the drastic reduction in fossil generation in the High Renewable case, as well as the fact that the DEG renewables are displacing central station renewables rather than fossil generation.

While MRW believes the Rate Impact Measure (RIM) test should be at most an advisory criterion for evaluating energy policy options, the RIM benefit-cost results are included here for perspective. Table ES-4 shows the results for these same four cases under the RIM test. For each case, two RIM benefit-cost ratios are shown: one when the impact of the reduced behind-the-meter load is included in the calculation, and one where only the value of the exported DEG energy is included. In all four cases, the RIM benefit-cost ratios are on the order of 0.8 to 1.0. The cases with the lowest RIM results are the two with residential rate sensitivities, with benefit-cost ratios at 0.8. The High Renewables case causes the least rate impact, with benefit-cost ratios of 0.9-1.0.

Table ES-4. Rate Impact Measure Test Benefit-Cost Ratio
Overall/Export Only

Case	All Classes	Residential	Non-residential
TASC Proposal	0.85/0.80	0.86/0.80	0.83/0.80
With NBCs	0.87/0.80	0.88/0.79	0.85/0.84
High MB	0.89/0.80	0.91/0.79	0.83/0.84
High Renewables	1.00/0.94	1.00/0.92	1.00/0.92

Conclusions

Based on analysis using the Public Tool, MRW finds continuation of NEM as currently structured in California meets the three key criteria set out in AB 327: (a) allow customer DEG to continue to grow sustainably; (b) that the tariff be based on the costs and benefits of the DEG; and (c) that the benefits of the successor tariff to all customers approximately equal the costs. With respect to the first criterion, NEM growth, on a megawatt per year basis, DEG growth is seen to be on the same order as that which the industry has experienced in the past four years. Second, an NEM tariff can reflect the costs and benefits of the DEG, as customers can experience positive, but not excessive, financial benefits. Third, the benefits of an NEM tariff to all customers can equal, or exceed, the costs. This is shown by the positive benefit-cost ratios in the Total Resource Cost test and the Societal Cost Test. Even if one applies that more stringent Rate Impact Measure test, the benefit cost ratios are between 0.8 and 1.0. Given the minimal weight the Commission places on the RIM test in evaluating energy policies such as energy efficiency and demand response, coupled with the facts that the ratios are within 20% of parity and broader societal impacts are not accounted for, the legislative directive that benefits approximately equal costs for all customers can be met.

These results, along with any other outputs from the Public Tool, must be viewed in light of its inherent limitations and uncertainties. The fact that the metrics for NEM are positive using the Public Tool cannot be taking in isolation: other benefits (and costs) such as increased local and statewide economic activity, environmental benefits and customer choice must also be taken into consideration when forming the successor tariff to the current NEM in California.

I. INTRODUCTION

California's net energy metering (NEM) program is a billing mechanism designed to facilitate the installation of customer-side distributed renewable energy generation (DEG). It was established in 1995 by Senate Bill 656, codified in Public Utilities Code Section 2827. Under NEM, customer-generators receive a full retail-rate bill credit for power generated by their on-site system that is fed back into the power grid during times when generation exceeds onsite energy demand. The credit is used to offset the customers' electricity bills, and it may be rolled over to subsequent bills for up to a year.

In October 2013, Governor Brown signed Assembly Bill (AB) 327, which, among other things, ordered the California Public Utilities Commission (CPUC or Commission) to develop a successor to the existing NEM tariffs by December 31, 2015, to be implemented on the earlier of July 1, 2017 or when the utilities' NEM caps are reached. Part of the legislative direction was that the NEM successor tariff should (a) allow customer-sited DEG to continue to grow sustainably; (b) that the tariff be based on the costs and benefits of the DEG; and (c) that the benefits of the successor tariff to all customers approximately equal the costs.

On July 10, 2014, the Commission opened Rulemaking (R.)14-07-002 to develop one or more successor tariffs/contracts to the existing NEM tariffs pursuant to AB 327. The Order included direction to the Energy Division to develop "a tool for estimating the costs and benefits of various NEM successor tariff options or rate scenarios (known as the Public Tool)."[4] Workshops were held for parties to have input on: what the Public Tool should do and be used for (August 2014); its basic structure and functionality (December 2014); and the operation and usage of the Tool (March 2015). After feedback from parties testing the Public Tool, the final version was released July 17.

The Alliance for Solar Choice (TASC) retained MRW & Associates, LLC to assist TASC by providing recommendations and feedback to the Energy Division during the development of the Public Tool, review the tool when it is released, and provide analysis and comments on the tool's accuracy and usefulness in evaluating successor NEM tariffs. This report presents MRW's review and critique of the Public Tool, along with the results of various scenarios that MRW believed would be appropriate to evaluate.

[4] Order Instituting Rulemaking 14-07-002, page 10. July 10, 2014.

II. THE PUBLIC TOOL

This section provides high-level description of the Public Tool, along with MRW's general views and comments. Details concerning the Public Tool, its use, and development can be found at: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

A. Purpose and Background

In order to respond to the Commission's direction in the July 10 order, Energy Division Staff (ED Staff or Staff) retained Energy and Environmental Economics, Inc. (E3) to develop the Public Tool. The goal of the Public Tool was to allow parties in the proceeding to test various options for a successor to the existing NEM tariffs against the provisions contained in AB 327.

The Public Tool is an Excel-based model that provides a common framework to model the impact of alternative rate designs, input assumptions, and policy scenarios on specific successor tariff/contract designs. It was developed to:

1) To provide a common "language" to talk about all specific proposals and ideas.
2) To provide an equal opportunity for all parties to analyze and test their proposals and ideas in meeting the potential scope of requirements set forth in AB 327, without favoring a single approach.
3) To provide auditability and vetting of the underlying calculations and inputs by parties.

The rationale behind the Public Tool is sound. In MRW's experience, parties in complex policy proceedings often find themselves using the same words to mean very different things, or they have to rely upon parties (such as the investor-owned utilities, (IOUs)) who have the resources to perform the detailed analysis. This prevents some parties from being able to participate in a meaningful a way, while it also prevents other parties from examining the detailed modeling and analysis, as the IOU models are often proprietary or contain confidential information. By creating this common platform, the Commission hopes to, and to a large degree has succeeded in, providing a common way for parties in the NEM successor tariff proceeding to discuss and present proposals in a more effective way.

As noted by the Staff, the Public Tool is not designed to pick a "best" answer, but instead provide a useful (but not sole) input in formulating future DEG policy in California.

B. Basic Structure

The Public Tool consists of three, large linked Excel Spreadsheets, along with VBA macro code that performs detailed analysis and transfers data among the three spreadsheets. The three spreadsheet modules are:

- Public Tool: This module contains the primary inputs, presents the results, and performs or retains data from all the major analysis. This includes calculating (a) the adoption of each type of DEG technology by each customer bin (see third bullet for description of these bins); (b) the rates for each class and IOU; (c) the energy, capacity and cost impact on the IOUs from the DEG adoption; (d) the avoided costs; and (e) the cost-effectiveness metrics. When fully populated, the Public Tool file is 48 megabytes.
- Revenue Requirement: This module calculates the annual utility revenue requirement and is based on the Lawrence Berkeley National Laboratory **FIN**ancial impacts of **D**istributed **E**nergy **R**esources (FINDER) model. The Revenue Requirement model file is 18 megabytes.
- Billing Determinants Database: E3 divides the three IOU's customers into 685 "bins." Each bin contains the usage profile of a group of similar customers (i.e., same tariff class and similar usage profile). This includes 18 different climate zones for residential customers. This excel database is 43 megabytes.

Using VBA macros, key usage and cost data are interactively passed between the Public Tool and Revenue Requirement models, so that changes in the utility's loads and costs caused by DEG adoption can be accounted for.

The Public Tool presents a number of results that can be used to evaluate a proposed NEM successor tariff:

- The California Standard Practice Manual cost-benefit tests, presented as benefit-cost ratios, and net benefits (costs), and levelized benefits and costs.
- "Cost-to-serve" indices, as developed in the 2013 NEM cost-effectiveness proceeding.
- Annual and cumulative DEG generation amounts (kW installed, number of installations).
- Cumulative and annual renewable generation and GHG reduction.
- Utility rate impacts.

Each of these indices can be presented for specific combinations of utility, customer class, DEG technology, and DEG installation year.

Again, more detail on the model's operation and assumptions can be found at the link to the CPUC above.

C. General Observations and Concerns

The Public Tool breaks new ground for analyzing distributed generation. It provides immense flexibility by allowing users to input different DEG characteristics, retail rates, rate structures, avoided costs, certain revenue requirement parameters, and discount rates to name but a few. It allows limited feedback between the impacts of DEG on both avoided costs and rates. These features allow policy makers in California to better understand the trade-offs and impacts of more and different policy levers than any prior tool.

But in all modeling tools, there is a balance between ease of use and comprehensiveness. Models that are intuitive and can be easily picked up and used often must sacrifice detailed analysis and simplify calculations and parameters. A more complex, precise model will factor in many more likely important parameters and variables, but will be much more difficult to master and operate.

The Pubic Tool skews towards comprehensiveness. As listed above, there are myriad of variables and policy levers that can be adjusted, as well as detailed calculations. The drawback of this approach, however, has been keenly felt. Because of its complexity, the model was more than two months late in being delivered to the parties in the proceeding. Three iterations, including two "final" versions have been issued. Even then, as described below, problems have been identified. The Public Tool requires over 4 hours to execute one run, greatly limiting the users' ability to conduct sensitivity analysis. . In fact, TASC leased ten cloud-based computers to conduct runs for MRW so that as many results could be modeled as needed due to time constraints from correcting the model multiple times.

Even with all its variables, there are still options that MRW wished it could have run. For example, in Decision (D.)15-07-001the Commission made sweeping changes to residential rates. Among other elements, this decision called for a "super energy user" rate tier set at 400% of the baseline as well as a transition to time-of-use rates. Given the model's data structures, the super energy user rate could not be implemented, nor could the model phase-in any rate-based policy. While the modeling work-arounds specified by the Energy Division for these rate changes are adequate for this study, it illustrates that even a model as complex as the Public Tool cannot consider every possible situation that a user might want to model.

MRW's greater concern is the large amount of "default" data in the Tool and the ability of users to understand that data. Because it so large and complex, the less skilled user could easily place more confidence in the results than is warranted. Much of the default data are based on the model designer's judgment for values that other knowledgeable parties could—and do—find to be problematic. MRW and other knowledgeable and skilled parties (such as Crossborder Energy) have spent literally hundreds of hours reviewing the detailed assumptions and experimenting with the Public Tool to understanding how the various assumptions interrelate. Despite this investment of resources, MRW still believes there are elements of the Public Tool that are "black box." This is partially due to the sheer size of the model, but also by the fact that many of the key calculations and manipulations are conducted in VBA marcos and not in the spreadsheets themselves. For some significant inputs, such as the avoided costs at the distribution level, it is impossible for third parties to verify accuracy due to confidentiality agreements between the utilities and E3. Furthermore, as will be discussed later in this report, parameters that can have a profound impact on the results can be non-intuitive and buried deep in the model.

All this leads to two fundamental concerns: opacity and false precision. For parties and individuals experienced in DEG technologies, California energy policy, and CPUC ratemaking, there remain areas of the model that simply cannot be vetted or verified. Less experienced parties may unknowingly come to believe that because the model is big and complex and appears to be comprehensive, the results it provides must be right. But those results are built upon a foundation of assumptions, which are subject to both uncertainty and the judgment of those who entered the assumptions.

Because of the inherent uncertainty in a model as complex as the Public Tool, MRW cautions the users of the Public Tool to see its results as indicative and directional rather than precisely accurate. For example, the difference between a benefit-cost ratio of 0.95 and 1.07 should be considered with care as the difference between the two numbers may not be as meaningful as they appear. It may indicate that one policy may be more cost-effective in one metric or another, or it may not due to the uncertainty inherent in the Public Tool. Accordingly, the Public Tool should be used as one of many tools and inputs to advise DEG policy, but should not alone be relied upon to set policy.

III. PUBLIC TOOL ISSUES AND MODIFICATIONS

As noted, there are many assumptions built into the Public Tool, some clearly labeled and some not. This section reviews the problematic areas of the Public Tool and explains the modifications that MRW made to address identified issues. Most are simply differences in professional opinion, while a few are remaining errors that MRW found but have not been corrected in the Final Public Tool.

A. Adoption Module

How much DEG, and of what type, is obviously an important factor evaluating alternative net metering policies. In fact, the DEG adoption rates are, in and of themselves, a key metric for evaluating net energy metering policies: Section 2827.1(b)(1) of the California Public Utilities Code require that CPUC policies allow for "sustainable growth" in customer-sited renewable DEG. Thus, whether or not a policy can be demonstrated to meet this criterion using the Public Tool depends exclusively on the Tool's adoption algorithm.

According to E3, the Public Tool adoption methodology is based largely on NREL's Solar

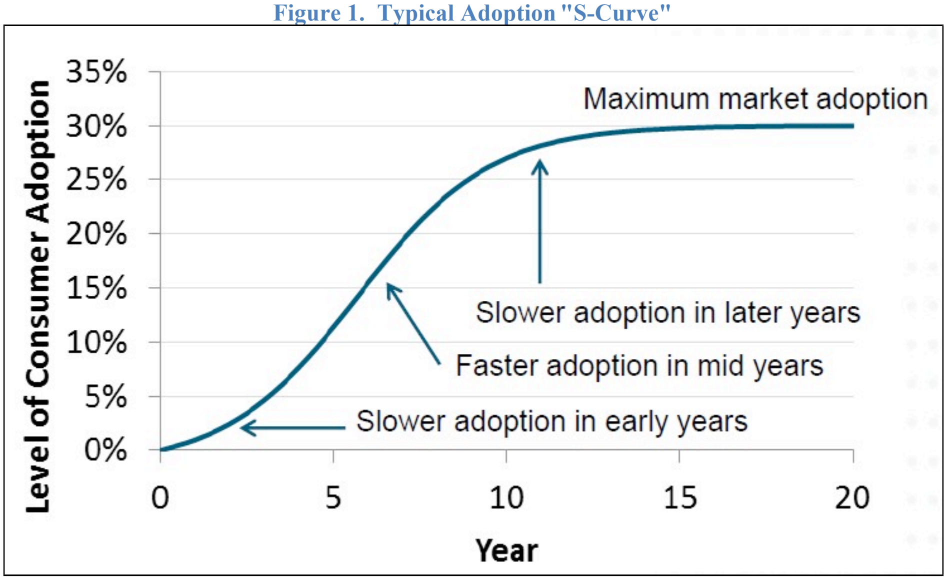
Deployment System Model (SolarDS), which simulates the potential adoption of solar PV. The Tool's adoption algorithm first calculates an implied simple payback for each DEG technology in each year and bin. The DEG technology is sized to one of three set sizes: meeting 33% of the bin's representative usage, 67% of the usage, or 100% of the usage. The model then calculates the maximum market share of the technology:

$$\text{Maximum market share} = e^{(\text{-payback sensitivity parameter} \ * \ \text{payback period})}$$

The model then scales this by the technical potential for each combination of technology and customer type. Because multiple technologies could have positive market adoption potential for any customer class, the model distributes the technologies in that customer class *pro- rata* based on their market potential.

With the scaled market potential for each DEG technology in each customer class, the Tool's algorithm then applies an "S-curve" to determine the rate at which customers adopt the technology. A sample S-curve is shown in Figure 1, below.

Figure 1. Typical Adoption "S-Curve"



1. General Concerns

While the basic logic of this protocol makes theoretical sense—estimate the market and technical potentials, and assume a phase-in rate—there are a number of important variables that are both uncertain and buried, such as technical potential, "the payback sensitivity parameter," the sizing of the DEG system, and the shape of the "S-curve." While E3 used reputable sources for these, generally from the National Renewable Energy Laboratory (NREL), there are still uncertainties in the underlying data.

Of particular concern is the compounding effect, where uncertain assumptions and parameters are layered on top of each other. When multiplying uncertain variables, the uncertainty of the product increases. Specifically, if you multiply two independent parameters, A and B, the variance (the square of the square root) is greater than the product of the variances (var) of the two parameters:

$$\text{var}(A \times B) = \text{var}(A)\text{var}(B) + \text{var}(A)E(B)^2 + \text{var}(B)E(A)^2$$

Where:

var (A) = variance of parameter A (or B)

E (A) = expected value of parameter A (or B)

Consider two parameters with normal distributions with expected values of 10 and variances of 2 (or square roots of 1.4). The expected value of the result would be 100, however the variance would not simply be 4 (2 x 2), but, given the formula above, it would be 404. This means that the standard deviation would be 21. Multiplying more than two uncertain parameters would result in even greater "spreading" of the distribution curve, meaning even greater uncertainty in the result.

What that means for the adoption module is that when a series of uncertain values (e.g., cost of the DG, performance of the DG, retail rates, payback sensitivity parameter, shape of the adoption S-curve) are combined, the adoption amounts become particularly uncertain. Many fewer potentially likely outcomes are close to the one calculated using the "average" values of the inputs. While conducting this analysis on a stochastic basis is not practical—the model already takes over 4 hours per run—one must keep in mind that the resulting adoptions are just one value and can vary markedly from the model output due to the high level of uncertainty built off of compounding assumptions.

2. DEG Sizes Adopted

Using the Public Tool's adoption algorithm, the mix of sizes, at least for solar DG, differs greatly from the historic mix. In general, the results are weighted highly towards the largest systems specified in the algorithm: in a typical model run, around 67% of customer adoption is "Large systems" that serve 100% of customers' loads. While this result follows the analytical approach taken—the system with the best payback dominates the adoptions—it does not match the actual historic distribution of installations. There are various reasons why a consumer might not install a system that meets 100% of his/her load, even if it is economically "the best." According to the Joint Solar Parties' March 16 comments in this proceeding:

1. Customers tend to be conservative. If the benefits are similar for different-sized systems, then most will choose the smaller system.
2. Many customers are limited by available roof space. Some people who are counted as potential customers in the technical potential of solar do not have enough roof space to size their systems to offset their entire load.
3. Solar customers on TOU rates should not size their system to offset 100% of onsite load.
4. Minimum bills can reduce or eliminate the benefits of sizing a system beyond a certain percentage of annual consumption.

To address this issue, MRW used SEIA's hard-wired changes to the adoption module to allocate the system size for solar PV based on the observed distribution in 2012. This change is designed to produce a more realistic distribution of solar system sizes, recognizing that economics alone does not determine system sizing. This change maintains the historical system size that customers have adopted in each bin of similarly-situated customers (i.e. if a bin was "small" in 2012, it will be "small" in 2017-2025), but it continues to allow the economics to determine how much of each bin's technical potential is adopted. Thus, if the economics favor large systems, the bins with large systems will fill up faster, resulting in a growing percentage adoption of large systems, but not to the degree that the Public Tool's algorithm would choose.

3. Market Disruption

While one cannot expect to be able to model market disruptions, given any technologically-focused product such as PV, such disruptions can, and do, occur. Furthermore, a policy that radically changes the business structure of any DEG technology will necessarily change the market for technology. I In the case of PV, a major change from the current paradigm, even if it might not changes the "economics" of the DEG PV, would likely disrupt the market due to the need to revamp sales practices, adjust marketing messaging, reeducate consumers considering PV on the new economics of the technology, etc.

Even if a full stochastic adoption analysis could be conducted, there are factors that cannot be modeled. For example, a breakthrough in storage technology could dramatically change the economics of PV + Storage, let alone the penetration of electric vehicles into the California market.

4. Storage Adoption

The Public Tool has inputs to allow for installing storage in addition to DEG. It allows for six "dispatch shapes" for combinations of PV and storage to: (1) minimize maximum demand; (2) allow energy arbitrage assuming an afternoon peak; (3) provide energy arbitrage that assumes an early evening peak; (4-6) dispatches that maximize grid benefit under the three RPS scenarios (33%, 40%, 50%).

Even with the narrow requirements included in the model, the assumed adoption rates are strikingly small. Setting the cost of storage equal to the storage incentive level should result in high adoption of storage. But it does not. When the Public Tool is run such that the customer's net cost of storage was negligible, (i.e., setting the storage price equal to the SGIP incentive) the adoption rates are very small. This includes scenarios with this low-cost storage in addition to retail rates with significant TOU rate differentials and large demand charges, which should support both TOU rate arbitrage and demand charge minimization. Nonetheless, the Public Tool continued to produce very small adoption levels. When queried about this odd result, the response from E3 was that that low storage adoption "is most likely due to poor customer economics."[5] Given that the scenarios run where storage was free and opportunity for daily price arbitrage was assumed still resulted in minimal storage, this response does not make sense.

In addition, in this low-cost storage / high TOU differential / high demand charge scenario there is virtually no difference in the avoided cost benefits for solar compared to solar plus storage. Given storage increases solar's effective load carrying capacity (ELCC) and that one can explicitly dispatch storage for maximizing grid benefit, one would expect storage to markedly increase avoided cost benefits. Considering that many parties have grave concerns about the rate impact of DEG and other behind-the-meter actions, the fact that storage does not appear to provide any discernible benefit to the grid is troubling.

Overall, MRW believes that the storage module should not be relied upon. Even though the model is extraordinarily detailed, attempting to model storage on top of all the other elements in the model appears to have proven impractical. If the Commission or others wish to analyze the economics of storage, a separate model that is better focused on that question should be developed and used.

5. Expected Rate Escalation

Part of the Public Tool's algorithm for estimating DEG adoption is the perceived economics of each DEG from the customers' perspective. Included in that algorithm is the annual rate at which the retail rates are expected to increase. This means, appropriately, that technology adoption is not based on perfect foresight of rates, but rather it is based on the cost of the DEG system at the time, combined with the expected rate savings.

[55] Documentation on adjustments to the Draft Version of the Public Tool to produce the Final Version of the Public Tool (Proceeding R.14-07-002). Response to Question 45.

The Public Tool's default value for this expected rate escalation is 5% per year. This is high compared to both the rate increases the Public Tool calculates, as well as what historic rate trends.[6] Based on this data, MRW reduced the expected rate to 3%. [Public Tool:Key Driver Inputs:C29]

The impact on the performance metrics of this variable is discussed in Section **Error! Reference source not found.**, below.

B. Rates

The Public Tool includes specific rates for residential customers; the small, medium and large commercial customers; the industrial class, and agriculture. For the non-residential classes, the default values in the Tool did not reflect current rates and rate structures. To correct for this, MRW updated the following non-residential rates to reflect current tariffs. [Public Tool:Advanced Rate Inputs]

Table 1. Rates Used in Public Tool Modeling

	PG&E	SCE	SDG&E
Small Commercial			
Default		TOU-GS-1	TOU-A
With DEG		TOU-GS-1	TOU-A
Medium Commercial			
Default	A-10 Secondary	TOU-GS-3 Secondary (Opt. B)	AL-TOU Primary
With DEG	A-10 Secondary	TOU-GS-3 Secondary (Opt. R)	DG-R
Large Commercial			
Default	E-19 Primary	TOU-8 Secondary (Opt. B)	AL-TOU Primary
With DEG	E-19 Primary (Option R)	TOU-8 Secondary (Opt. R)	DG-R
Industrial			
Default	E-20 Primary	TOU-8 Primary (Opt. B)	AL-TOU Primary
With DEG	E-20 Primary (Option R)	TOU-8 Primary (Opt. R)	DG-R
Agricultural			
Default	AG-4B-E Primary	TOU-PA-2 (Opt. B)	
With DEG	AG-4B-E Primary	TOU-PA-2 (Opt. B)	

[6] US DOE Energy Information Administration data shows that the average rate increase in California from 2004-2014 was 2.9% per year.

A. Revenue Requirements

1. Distribution Capital Expenses

As noted earlier, the Public Tool has a module that calculates the annual revenue requirement of each of the three IOUs through 2050. This module disaggregates the major utility cost streams and forecasts them independently before combining them and calculating the resulting retail rates. One key parameter is the annual capital expenses each IOU spends on its distribution system. In fact, unlike any other specific utility cost stream, the "Key Driver Inputs" section of the Public Tool includes inputs to allow the user to scale the distribution capital expenses.

MRW set these values at 80% for PG&E and SCE and 70% for SDG&E. The 20% reductions for PG&E and SCE reflect the large emphases in utilities' GRCs on getting their respective systems up to higher levels of safety as well as replacing aging assets. [Public Tool:Key Driver Inputs:C22-C24] For example, in its 2012 Phase I General Rate Case (GRC) Application (A. 12-11-009) PG&E stated that, "Broadly speaking, the utility industry has underinvested in our energy systems over the past 20 years, relative to demand and economic growth," and "PG&E is determined to close the energy infrastructure investment gap in northern and central California."[7] In its SCE 2013 GRC, SCE stated, "Our request in this 2015 General Rate Case (GRC) contemplates significant investment in the electric infrastructure to replace our aging equipment and to support State energy and environmental policy objectives. The Commission has recognized the need for infrastructure investment in its decision on our 2012 GRC."[8] In the long run, MRW sees these as much needed but shorter-term deviations in the utilities' investment stream, rather than a value from which to simply extrapolate. One would reasonably assume that once the neglected aging infrastructure has been replaced, that catch-up investments would no longer be needed. As such, MRW set the PG&E and SCE distribution rate base cost adjustment factors at 80%. The reduction for SDG&E reflects the fact that the model's values are from an unapproved application (A.14-11-003). Only rarely, if ever, is a utility's full request granted.[9]

Furthermore, the model assumes that 11% of the distribution capital investment is due to system expansion, and thus potentially deferrable by reducing load. [Revenue Requirement:RR Inputs:G346-G348] It is important to be clear that the 11% assumption is functionally equivalent to determining that 89% of utility's distribution-related capital expenditures and 100% of the utility's distribution operating expenses cannot be avoided, no matter the reduction in load. While MRW believes this 11/100 ratio of expansion to total costs may be "correct," it does not

[7] A.13-11-009 Exhibit PG&E-1, at 1-3.
[8] A.13-11-003. SCE-1, at 1.
[9] E.g., In SDG&E's most recent Phase 1 GRC (A.12-04-016), SDG&E requested a $6.9 million decrease but the litigated outcome was a decrease of $28 million.

follow that non-expansion distribution capital investment is unaffected by reduced loading on existing circuits. DG can both defer distribution capital investment by reducing power being met by the circuit as well as potentially reduce the size of equipment being replaced.[10] Because of these factors, MRW increased the 11% of distribution capital investment that is reducible by DG to 22% (double), expanding the potentially avoidable distribution cost from $390 million to $781 million per year in the Revenue Requirement model. This is out of a total distribution related capital expenditures in the Revenue Requirement model of $3,545 million per year (2012$). In addition, it is worth noting the Commission's Distribution Resource Planning proceeding contemplates leveraging DEGs to provide an alternative to more traditional utility investments in the distribution system.[11]

2. Generation Capital Expenses

Analogous to the scalers available to modify the annual distribution capital expenses are scalers to modify the generation capital expenses. MRW assumed generation rate base cost adjustment factors of 75% for SDG&E, which reflects the fact that the SDG&E inputs were based on an application (A.14-11-003) and not an approved GRC. [Revenue Requirement:RR Inputs:G200] In addition, the Revenue Requirement Model cites to a table in SDG&E's GRC filing that includes a number of factors which have to be adjusted or removed to achieve the generation capital expense value. Instead, MRW used $8 million, from GRC Exhibit SDG&E-11, which explicitly identifies SDG&E's generation capital expenditures. [Revenue Requirement:RR Calculations:B807]

3. Diablo Canyon O&M

In review of the Revenue Requirement Model, MRW found that the costs associated with the retirement of Diablo Canyon upon the expiration of its license were not properly treated. When this was pointed out to E3, the error in the Diablo Canyon capital expenditure stream was corrected, but the O&M error was not. In particular, when Diablo Canyon is removed from service in 2024 (assuming retirement at the end of its license), the amount associated with the plant's O&M ($300 million) is not removed from the generation O&M. This clearly overstates the generation O&M in 2024 and beyond. To correct this, MRW removed the Diablo Canyon

[10] M.A. Cohen et al., Energy Institute at Haas, "Economic Effects of Distributed PV Generation on California's Distribution System" (2015) p 2. http://ei.haas.berkeley.edu/research/papers/WP260.pdf (finding that for circuits where peak load or load growth is high, "the value on some circuits could be a significant fraction of the installed cost of PV").

[11] See Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, pg. 8.

O&M amount from PG&E's post-2024 revenue requirement. [Revenue Requirement:RR Inputs:G380-G384, G396-G400]

4. Fossil Steam Capacity Factor

MRW reduced the steam capacity factor from 10% to 5%. [Revenue Requirement:RR Inputs:G200] According to the EPA's Emissions & Generation Resource Integrated Database (eGRID), for the most recent year available, 2010, the steam generators in the CAISO control area operated at an average capacity factor of 4.6%. Given the continued retirement of steam generators in the state (particularly with the OTC units being removed from service), steam boilers will become increasingly less used. Thus, even the 5% used by MRW is its modeling may overstate the steam generator output.

5. Revenue Allocation

The Revenue Requirement Model allows users to choose from one of three methods to allocate the costs among the customer classes:

1) Equal Percent Marginal Cost (EPMC)
2) Maintaining the current deviations from marginal cost
3) Maintaining settlement rate relationships

Option 1, EPMC allocation, is theoretically preferred by the CPUC, but is rarely, if ever, directly implemented. The second method maintains the "current deviations" from EPMC allocation. The third method is to use the current relationships—i.e., to keep the same allocation percentages as are in place.

MRW uses option 3, Settlement Rate Relationships, rather than option 2, Maintaining the Current Deviations. [Revenue Requirement:RR Inputs:D422] MRW has participated in every Phase 2 GRC since 2005. In all cases, the cost allocations were set in settlement based on black-box changes to the allocators that resulted in modest, often capped, changes to the percentage of revenue requirement borne by each class. While marginal costs were developed in the GRCs for non-allocation purposes, such as developing Economic Development Rates, they have not been directly used for cost allocation. As such, MRW finds it more reasonable to assume that the same basic allocation relationships (percentages) among the rate classes continue, rather than to directly tie the cost allocation to the marginal cost, be it directly by using the EPMC or equal deviation from EPMC.

6. DEG Interconnection Costs

The costs to interconnect DEG systems into the local grid assigned to each of the three utilities in the Public Tool differ markedly—sometimes by more than a factor of five. MRW does not find this level of variation to be reasonable. While local labor and material costs can reasonably vary across the state, the variation seen is questionable. MRW therefore assumed SCE's interconnection costs for PG&E and SDG&E. [Revenue Requirement:RR Calculations:Row 266]

7. Solar Integration Costs

MRW relied upon E3's June 12, 2015 "Marginal Integration Cost Calculations" for solar of $2.38 per MWh for the 33% RPS. Based on updated calculations using method adopted in D. 14-11-042, integration cost adders for 40% and 50% RPS cases use the same ratios to the 33% RPS case shown for the default Public Tool values. This results in adders of $2.79 per MWh and $3.38 per MWh for the 40% RPS and 50% RPS cases, respectively. [Revenue Requirement:RR Inputs:G414-G416]

B. Avoided Costs

Avoided costs are critical in evaluating any policy that affects behind-the-meter usage. In addition to avoided generation and generating capacity costs, the model provides for including avoided transmission, subtransmission and distribution costs. Default avoided subtransmission and distribution costs are included in Public Tool assumptions, but users are allowed to scale them.

1. Distribution and Sub-transmission Avoided Costs

The distribution and sub-transmission avoided costs in the Public Tool are unverifiable. This opacity is due to more than the complexity leading to pseudo "black box" results discussed earlier. Rather, the lack of transparency in distribution and sub-transmission avoided costs is inherent in the methodology. Energy Division's June 2015 proposal to revise the IOU's Demand Response Cost Effectiveness Protocols identifies the key weakness in the current approach for determining the potential of distribution-related avoided cost.

> *The model for distribution-level avoided costs is more complex. The IOUs must provide confidential lists of distribution system project upgrades, which are planned for the next five to ten years. Using this information, forecasts of load growth, and known capacity constraints in the project areas, E3 calculates the costs savings that could occur if the projects are deferred. This "Present Worth" method is more accurate than the previous method. However, it does have the disadvantage that it uses confidential data to determine results. While the Commission normally discourages the*

> *use of confidential data in cost-effectiveness analysis, an exception is made in this case because of the difficultly in determining reasonable and consistent values for avoided T&D costs, until and unless another method emerges which uses only publicly-available data… The accuracy of this model depends on the provision of detailed, accurate and timely information from the IOUs. The IOUs are expected to comply with the need for this information so that accurate avoided T&D capacity costs can be determined.*
>
> *2014 Revised Demand Response Cost Effectiveness Protocols*
> *Energy Division Staff Proposal (revised June 2015)*

While the Commission provides practical justification for the methodology (i.e., there are no better alternatives that use publicly-available data), adopting the default values in the Public Tool is problematic for the reasons described in more detail below.

First, the method by which the default distribution values are determined is structurally flawed. While there is no doubt a good-faith effort by utility and E3 employees to determine the appropriate list of distribution projects and their costs that can be deferred by DEG, they are still proprietary and unverifiable by outside parties. To the extent E3 does not possess the expertise in distribution planning and operations to provide an authoritative 'check' on the utility recommendations, the methodology may yield much lower default values than if the process was exposed to a more robust, public process based on publicly-available data.

Second, the default values are inconsistent with how utilities determine the cost of marginal distribution capacity in General Rate Cases. According to SDG&E's 2016 Phase II General Rate Case testimony, "marginal distribution customer costs represent the cost of providing an individual customer access to electrical service." While the utilities have slightly different calculations to allocate costs, all utilities rely on a marginal cost calculation, expressed in $/kw-year, to determine the "cost" of providing distribution service. The Public Tool uses these inputs in the Revenue Requirement Model to allocate costs.

In contrast, when determining the value of distribution capacity provided by DEG in the Avoided Cost module, for SCE and SDG&E the Public Tool is uses much lower marginal benefit values. This inconsistency is not warranted. Whereas parties can disagree about the ability of DEGs to provide capacity, it is not reasonable to assume the value of providing incremental distribution capacity to the utility is less valuable than the cost of the utility providing incremental distribution capacity to its customers. The contrasting values are displayed below.

Distribution Capacity

Distribution Capacity
Distribution Power Quality
Distribution Resiliency
Distribution Reliability

Table 2. C IOU's Cost/Value of Distribution Capacity

IOU	Claimed "Cost" of Customer Distribution Capacity	Claimed "Value" of DER Distribution Capacity (Avoided Costs)
Scope	Subtransmission and Distribution Capacity	Subtransmission and Distribution Capacity
Source	Revenue Requirement Module	Public Tool Module
SCE	$118/kw-year	$53/kw-year
PG&E	$79/kw-year	$79/kw-year
SDG&E	$102/kw-year	$52/kw-year

Third, the default values are inconsistent with recent CPUC policies and the utility's recent progress in establishing additional distribution avoided cost categories. On July 1, 2015, CPUC-jurisdictional utilities filed Distribution Resource Plans (DRPs) in compliance with Assembly Bill 327. Common utility goals in developing the DRPs were to, among other things, animate opportunities for DEGs to realize benefits through provision of grid services. There is no question the DRPs represent a significant step forward for the power industry, and are a preview of the future of distribution planning and operations in the state of California. Failing to consider these plans, particularly given the long time horizon analyzed in the Public Tool (to 2050), will skew results and result in potentially in misleading modeling results.

Importantly, each utility's DRP included new methodologies to value the location-specific benefits of distributed energy resources, codifying four distributed avoided cost categories, which the utilities will use in the future to value DEGs.

Table 3. Distribution Avoided Cost Categories – Public Tool vs. July 1, 2015 DRPs

To be clear, the current methodology for determining distribution marginal cost is based on the cost to serve incremental units of peak demand, which can include the general costs attributed to maintaining sufficient capacity, power quality, reliability and resiliency associated with incremental demand. However, the Public Tool only considers this full suite of cost categories to the extent they are part of expansion-related investments. The Public Tool's default value for expansion-related categories is 11% of annual capital expenditures, leaving the vast majority of distribution capital and operating expenditures excluded, even if there is potential to avoid non-capacity related investments in power quality, reliability and resiliency.

While the utilities have significant work to be done in the coming years to animate markets for grid services and refine location-specific valuation of DEG benefits, it is imperative that the Public Tool consider the full value of DEGs on the grid envisioned in the Distribution Resource Plans.

For these reasons, MRW adopted the SDG&E's and SCE's marginal distribution avoided that appear on the Revenue Requirement Model. [Public Tool:Avoided Cost Calcs:B325:E350]

2. Energy

The Public Tools allows for a multiplier to be applied to the model's default energy avoided cost. A recent study by Kevala Analytics, an energy data analytics firm, examined the locational value of solar PV in California using geospatial mapping of PV locations and modeling the interactions on the grid.[12] Based on the Kevala analysis, MRW used a 4.8% energy avoided cost multiplier to account for the additional locational benefits of solar PV.[13]

3. Transmission

No avoided transmission costs are included and are thus implicitly valued at zero. Historically, transmission costs have been excluded due to practical jurisdictional lines that exist between transmission and sub-transmission cost recovery. For example, SCE's 2015 General Rate Case Phase II application summarized this limitation in its marginal cost scope section:

> *"SCE's higher voltage transmission facilities are subject to FERC jurisdiction and are under the operational control of the California Independent System Operator (ISO). FERC-jurisdictional (ISO-controlled) assets and activities have not been included in the marginal cost study. Marginal costs associated with the FERC-jurisdictional facilities and activities are excluded from marginal cost revenues and the revenue allocation process because FERC—not the California Public Utilities Commission (CPUC)—is responsible for determining revenue requirements and rates associated with these facilities and activities."*
>
> *SCE GRC Phase 2 – SCE-02 Marginal Cost and Sales Forecast Page 10*

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[12] Kevala Whitepaper: "Geography Dependent Valuation Quantifying the bias in statewide averages in PV valuation methodologies in California. August, 2105. http://kevalaanalytics.com/

[13] The Public Tool considers other DEG technologies, solar PV dominates in both capacity and number of installations.

Whereas the jurisdictional issue is practical for ratemaking purposes, continuing to use this limited scope for the purposes of determining a NEM Successor Tariff is inappropriate. The consideration of technical and the corresponding economic benefits of DEG should not be limited to CPUC-jurisdictional facilities, since the costs of transmission are borne by utility ratepayers, and the benefits of reduced transmission costs would similarly accrue to utility ratepayers.

In order to arrive at a non-zero avoided transmission cost amount, a regression analysis was performed linking the bulk transmission revenue requirement as a function of CAISO peak demand (prior to any adjustments for demand response). The slope of this regression, $87/kW-year was used as an alternative input to zero for the avoided transmission costs. [Public Tool:Key Driver Inputs:C16]

1. Other Unaccounted For Avoided Cost Elements

In addition to the avoided costs described and quantified above, other avoided costs and financial benefits of DEG exist but are not accounted for in the Public Tool. These include:

- **Fuel Price Hedge.** By reducing reliance on commodity fuels such as natural gas, DEG (along with other renewable resources), can reduce a utility's exposure to market swings and price spikes.[14]
- **Market Price Response.** DEG resources can not only reduce the amount of power that is purchased by the utility, but also assert downward pressure on electric and gas market prices. This occurs because higher-cost generating units are backed off the price-setting margin and replaced by lower cost units setting the market price. This effect was acknowledged in a recent Ohio Public Utilities Commission report, "Renewable Resources and Wholesale Price Suppression."[15] This report estimated the impact to be on the order of -0.5%.

C. Treatment of Renewables

The Public Tool treats renewable energy credits (RECs) generated by the DEG systems in one of two ways, depending upon how the DEG owner is being compensated for the DEG's generation.

[14] Jenkin, "Thomas et al, The Use of Solar and Wind as a Physical Hedge against Price Variability within a Generation Portfolio," National Renewable Laboratory Technical Report NREL/TP-6A20-59065. August 2013. http://www.nrel.gov/docs/fy13osti/59065.pdf

[15] Ohio Public Utilities Commission, "Renewable Resources and Wholesale Price Suppression." August 2013. http://cleanenergytransmission.org/uploads/Renewable%20Resources%20and%20Wholesale%20Price%20Suppression%20%282%29.pdf

When a value- or cost-based compensation option is selected (i.e. feed-in-tariff), the RECs generated by the DEG system can used by the utility to meet so-called "bucket 1" RPS requirements. If a NEM option is selected, then Bucket 1 treatment is not allowed.

For all NEM cases with full retail rate credits, the only impact of DEG on the utilities' RPS obligations is the amount of reduced load that they cause. That is, if the utility is under a 33% RPS obligation, then the DEG output reduces the utility's RPS requirement by 33% times the DEG output.

According to the Energy Division Q&A document, by policy choice, the CPUC will not consider allowing the host utility to use for RPS compliance any "Bucket 1" RECs generated by behind-the-meter DEG:

> The compatibility constraint is a political constraint, not a logic constraint. While the model will allow users to select "All NEM Successor DEG Gen Counts for Bucket 1" with all NEM successor structure options, the CPUC will not consider any proposals that award Bucket 1 RPS credit for generation credited at the full retail rate[16].

While this is the current policy, DEG RECS remaining with the system owner, MRW understands that this is a CPUC policy constraint and not one of statute. If the Bucket 1value of the RECs are transferred to the host IOU, then additional central-station renewable procurement could be deferred or eliminated.

The default treatment of NEM RECs may change due to legislative action. California Senate Bill 350, which would increase the California RPS requirement up from 33% to 50% by 2030, could also change the treatment of RECs from DEG systems. If passed, the bill would update the Public Utility Code to include Section 39913 (f)(3), which states that "[t]he commission may authorize a procurement entity [a utility, ESP, or CCA] to procure _ percent of retail sales of on-site generation within the area served by the procurement entity to serve local electricity needs." This could easily be implemented as allowing a certain percent of NEM generation to be treated as Bucket 1 RECS for RPS compliance purposes.

[16] Documentation on adjustments to the Draft Version of the Public Tool to produce the Final Version of the Public Tool (Proceeding R.14-07-002). Response to Question 66.

D. Treatment of Departing Load

The Public Tool and Revenue Requirement models include customers of direct access (DA) service and those served by community choice aggregators (CCAs), together referred to as Departing Load. This treatment is cursory; it takes the current "DA" retail market penetrations and holds them constant throughout the modeled time period. While this may be a reasonable assumption for DA, whose amount is statutorily capped, it is not for CCA. For example, the Revenue Requirement model does not include any CCA load for SCE, even though the City of Lancaster has filed a CCA plan and intends to begin its program by the end of 2015. Numerous other cities and counties throughout the state are also investigating CCA formation.

Second, the model also attempts to consider the "Power Charge Indifference Amount" (PCIA). In broad strokes, the PCIA is set so that departing load customers do not cause the rates of customers who remain in utility bundled service to increase. That is, it is set to keep them "indifferent" to the departing load customers' choice of alternative service. This amount is calculated each year per the process laid out in Decisions 06-07-030 and D11-12-018.

The PCIA calculation is far from trivial. It involves identifying the PPA and generation resources acquired by the host IOU prior to when the CCA or DA customer departs utility bundled service. The cost of these resources is compared to an administratively-calculated benchmark, and costs above the benchmark must be paid, in part, by the CCA or DA customer. The Revenue Requirement Model oversimplifies PCIA calculations and tends to overstate the values.

However, MRW does not see that calculation of DA and CCA customer participation or explicitly calculating the PCIA as needed for this exercise. First, DA and CCA customers pay the IOUs for the full transmission, distribution, and nonbypassable rate elements, the same as bundled customers. Thus, under a NEM regime, any DG installations by DA or CCA customers would have the same effect on these three rate elements as they would for DG installed by bundled customers. As for generation rates, the PCIA is explicitly formulated so that rates for bundled customers would not change.

Since in the long run, the cost of CCA and DA service will be generally comparable to IOU service, another approximation would be to consciously disregard CCA and DA in the Revenue Requirement Model and Public Tool calculations, rather than to attempt to forecast participation in these programs over 50 years and calculate the PCIA. When MRW implemented this change in the Public Tool, the effect was minimal—way beneath the level of general uncertainty in the model. As such, MRW chose to avoid controversy and not implement the CCA, DA, and PCIA corrections.

E. Evaluation Metrics

The June 4 Ruling explicitly notes that any party's third case must demonstrate that it meets the statutory criteria in P.U. Code Section 2827.1. In the March 16, 2015 Comments of the Joint Solar Parties (which included TASC), specific results metrics were identified for evaluating NEM Successor Tariff proposals. The performance of the TASC Proposal using these metrics is presented below.

1. Section 2827.1(b)(1): Continued Sustainable Growth

With respect to the requirement for continued sustainable growth (Section 2827.1(b)(1)), the Joint Solar Parties advocated that the Successor Tariff preserve and foster market conditions that ensure that customers continue to adopt customer-sited renewable DG at a rate of adoption and under customer terms that are sufficient to support multiyear industry investment and expansion. As noted in the March 16 Joint Solar Party Comments, this does not mean the continuation of the 30+% year-over-year growth seen in the 2011-2014 time frame in perpetuity, but rather that the absolute numbers of installations and capacity added should at least equal recent levels.

While MRW acknowledges that there is no consensus on these issues, we find that the metric proposed by the Joint Solar Parties[17] to be reasonable and use it when considering the continued sustainable growth criterion.

2. Section 2827.1(b)(3): Tariff be Based on the Costs And Benefits of the Renewable Generation Facility

In the Joint Solar Parties' March 16 Comments in this docket, the Solar Parties argued that the appropriate metric in which to consider this section of the statute is the California Standard Practice Manual (SPM) "Participant Cost Test." This test measures the costs and benefits of a DEG technology to the customers who adopt it. The Energy Division Staff in its June 3 report also adopted the Participant Cost Test as the measure by which proposed tariffs are evaluated for this criterion. Given that the broader benefit and cost implications of the successor tariff is considered in the Section 2827.1(b)(4) criterion, MRW finds that the Participant Cost Test to be a reasonable metric for the tariff being based on DEG costs and benefits.

[17] R.14-07-002, Comments Of The Alliance For Solar Choice, The Solar Energy Industries Association, The California Solar Energy Industries Association, And Vote Solar On Policy Issues Associated With Development Of Net Energy Metering Successor Standard Contract Or Tariff, March 16, 2015. Pp. 14-26

3. Section 2827.1(b)(4): Total Costs Approximately Equal Total Benefits to All Customers on the Grid

As noted earlier, the Public Tool presents the results in a number of ways, including two evaluation metrics that measure costs and cost effectiveness: the SPM tests and a "cost-to-serve" (COS) percentage. The definitions of the inputs and outputs to the SPM tests are well established and understood. However, as noted above, there is significant uncertainty in many of the model inputs, which results in the outputs being even more uncertain. Thus, as one examines the cost effectiveness of DEG using this tool, the results are better interpreted as indicative and not as precisely accurate.

The cost-to-serve index presents the modeled bills that NEM customers pay as a percentage of the modeled utility's costs to serve the customer (the "full cost of service"). This measure was introduced in 2012 as part of the CPUC's evaluation of ratepayer impacts of NEM, arising from the Assembly Bill 2514 requirement that the Commission identify "who benefits, and who bears the economic burden, if any, of the net energy metering program." The cost of service metric used in the Public Tool expands upon that developed in the 2012 ratepayer impact analysis, and deserves greater scrutiny.

The full cost of service consists of three elements: the General Rate Case fixed costs allocated to customers through the GRC; regulatory items like public purpose program costs; and the incremental costs of the utility not already accounted for in the GRC or Regulatory costs. Therefore, the full cost-to-serve is the marginal cost to serve the NEM customer plus assigned allocations of fixed and regulatory costs.

Although the model includes the cost-to-serve metric, MRW finds its use limited because of the uncertain and unvetted values going into the calculation. As the CPUC noted in its 2013 NEM Report,[18] there are many "caveats" to the test. Concerns raised by the Energy Division Staff include the lack of a standard defined approach to calculating the Cost of Service (i.e., each utility took a difference approach) and the difficulty in "exactly replicat[ing] the cost of service analysis for a sub-set of customers participating NEM, since the utilities evaluate cost of service at the customer class level."[19] The NEM Report also listed numerous other concerns raised by parties in that proceeding.[20]

The Energy Division's concerns are further reflected in its June 3 Report:

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[18] CPUC Energy Division, *California Net Energy Metering Ratepayer Impacts Evaluation*, October 2013.
[19] *Ibid,* Page 17.
[20] *Ibid*, pp. 88-89.

> However, as indicated in the 2013 NEM study, because a COS analysis doesn't capture how much participating customers should be paying relative to nonparticipating customers, and also because the results of a COS analysis are inextricably linked with broader rate design issues designed to support numerous Commission policies, caution should be applied when interpreting the results of this analysis.[21]

MRW shares these concerns and believes that how non-participating customers are affected by DEG should be considered. However, the best way to do so is to examine the direct effect on retail rates and to a lesser degree the Rate Impact Measure (RIM) Test. As can be seen in some of the Public Tool Runs, DEG can have what appears to be a low percentage recovery of the full cost to serve while having practically no impact on rates.

A. Opaque "Key" Assumptions

One of the challenges of a detailed model such as the Public Tool is that variables that can have profound effects on the results are not presented as a "key input," nor are they intuitive or easily accessed. Two examples are provided below. Given the hundreds of potential parameters that can be adjusted, others not identified here might also have significant impacts on the results; it is doubtful that these are the only two.

1. Utility Cost Allocation

On the "RR inputs" sheet of the Revenue Requirements Model, 95% of the way down the sheet in cell D422, is an option to select one of three revenue requirement allocation methodologies (i.e., how each IOU's revenue requirement is spread among the different customer classes). The first option is to use "EPMC" or equal percent marginal costs. This allocation method is theoretically preferred by the Commission, but in practice is never directly implemented. The second method maintains the "current deviations" from EPMC allocation. The third method is to use the current relationships—i.e., keep the same allocation percentages as are in place.

Unless one is intimately involved in the second phase of California regulated utility General Rate Cases, what these choices mean, let alone the differences among them, are truly opaque. Quite reasonably, the less knowledgeable user would likely just use the "default" value. However, which of these three one selects has a profound impact on the results. MRW ran three identical cases, generally using the recommended inputs described above, but changed only the revenue requirement allocation flag. The differences are shown in **Error! Reference source not found.**,

[21] CPUC Energy Division, *Energy Division Staff Paper on the AB 327 Successor Tariff or Contract,* June 3, 2015. Pp. 1-12 to 1-13.

elow. As the table shows, the default option, maintaining current deviations from EPMC, results in to greatest number of adoptions by a half-million or more (15%), while the RIM Test metric differed by 0.32 points from option 2 to option 3. From a TRC perspective, the policy could be either cost-effective, or not, depending upon the allocation method.

Table 4. Impact of Differing Cost Allocation Methods on Cost-Effectiveness Metrics

Cell D 422:	1	2 (default)	3
Allocation Choice	EPMC	Maintain current deviations	Maintain current rate relationships
RIM test	0.78	0.50	0.82
TRC Test	1.05	0.98	1.06
DEG Adoptions	3.0 million	3.5 million	2.9 million

The magnitude of the changes to these results are greater than different selections in the Public Tool's "Key Drivers" input discussed in Section IV.C to IV.D, above. The fact that this lever is not even in the Public Tool but the Revenue Requirement Model, and even then is over four hundred rows down in the RR Inputs tab, means that it is highly unlikely that it would be tested by anyone but the most diligent user.

2. Perceived Rate Escalation

As noted above, the Public Tool has an input for the rate escalation that customers assume when evaluating the future potential savings of a DEG system. This assumption is found on the Public Tool's Key Driver Inputs tab, in the "DEG Costs" box. The default value is 5% per year, while TASC found that 3% is more realistic. Like with the revenue requirement allocation choice, those without specific insight into the solar PV business would have no way of evaluating what an appropriate value for this input would be, and would thus likely simply keep the default. But as with the allocation, the bottom line results are surprisingly sensitive to this input. Cumulative impact of 1,000 MW. PCT added since 2017

IV. ANALYSIS OF NEM WITH THE PUBLIC TOOL

This section presents MRW's analysis of NEM policies using the Public Tool.

A. Key Assumptions

1. Model Inputs

Table 5 shows the key inputs that reflect TASC's proposal in R.14-07-002 (TASC Proposal). Except where noted, MRW used the Public Tool's default settings. TASC's Proposal actually is for DEG customers to pay the Public Purpose Program (PPP) rate for their gross usage. Because the non-bypassable functions in the Public Tool do not allow for treating PPP independently of other non-bypassables, the TASC Proposal results will fall between the "TASC Case" and the "NBC Case."

Table 5. Key Driver Inputs Used in the TASC Proposal

Policy Inputs	
2030 RPS Policy Target	33%
DEG Renewable Energy Credit (REC) Scenario	DEG Does Not Count for Bucket 1
Avoided Cost Inputs	
Natural Gas Price	Default
RPS PPA Costs	Default
Carbon Market Costs	High
Marginal Avoided Transmission Costs	$87.00
Marginal Avoided Energy Cost Locational Multiplier	4.8%
Marginal Avoided Subtransmission Cost Multiplier	100%[22]
Marginal Avoided Distribution Cost Multiplier	100%
DEG Costs	
Solar Cost Case	Base
Post 2017 DEG Program Costs Paid By	All Customers
Assumed Utility Rate Escalation (nominal)	3%
Compensation Tax Treatment	Tax Exempt
Societal Inputs	**2015 Value (2015 $)**
Societal Cost of Carbon	$36/tonne
Societal Cost of PM-10	$184/lb.
Societal Cost of NO_x	$24/lb.
Water Costs	$0.0012/kWh
Reliability and Land Use	$0.0240/kWh
Discount Rate Inputs	
Participant Nominal Discount Rate	9%
Utility Nominal Discount Rate	7%
Societal Nominal Discount Rate	5%
Inflation	2%
Rate Design	
Residential Rate Design	2 Tier Inclining Block
Residential Minimum Bill	$10/Mo.
NEM Structure	Full retail rate credit
Revenue Requirement Allocation	Maintain Current Percents

[22] Per Section III.B.1, MRW made adjustments to the distribution and subtransmission avoided costs elsewhere in the Public Tool.

2. Externalities

In economic analysis, an externality is a cost (or benefit) that affects a party who did not choose to incur that cost or benefit, i.e., a cost that is not included in the price of a good (environmental harm) that is not priced into the good. Estimates of these costs are included in the Societal Cost Test, and provided for in the Public tool. The values used are shown in the table above and discussed below.

Air Emissions. In electric utility benefit-cost analysis, the predominant externalities are environmental: costs imposed by power plant emissions on the local (or in the case of carbon dioxide, global) population. Explicit entries for the cost of air emissions of carbon, oxides of nitrogen (NOx), and particulate matter smaller than 10 microns (PM-10) are provided for in the Public Tool, along with slots for other values.

MRW conducted a literature review of expert opinions on values for these emissions, and found that the values differed significantly from source to source, often by an order of magnitude. For Carbon, MRW took an approximate median value shown in the literature, while for NOx and PM-10, we relied upon the EPA "Clean Power Plan."

Water Use Impacts. Particularly in the midst of the drought in California, water use is in the spotlight. To estimate the externality cost of water use in marginal power plants, MRW surveyed studies on the average water consumption of power plants as well as the cost of marginal water sources. For the marginal water consumption, we used the water consumption of a combined cycle with dry cooling (~2 gallons/MWh) and the cost of desalination ($2,800 per acre-foot of water), resulting the relatively low water externality of $0.00017/kWh. Obviously, if the marginal unit used a cooling tower, this value would be two orders of magnitude greater.

Reliability. Renewable DEG systems are widely distributed and unlikely to fail at the same time. Even when they do, the impact of any individual outage at a DEG location will be far less consequential than an outage at a grid-scale power plant. Furthermore, DEG systems are located at the point of end use, and thus also reduce the risk of outages due to transmission or distribution system failures. MRW relied upon research by the Sierra Club and SEIA to value the added reliability attributable to dispersed DEG systems.[23] Based on Sierra Club/SEIA analysis, the value of avoided interruptions for California IOUs can be monetized at $0.02 per kilowatt-hour.

It must further be noted that even though this benefit is accounted for in the "externalities"

[23] See attachment to SEIA's Proposal

inputs, it is not actually an externality. Reliability benefits should be reflected in the transmission and distribution avoided cost, but are not. However, rather than modify the Public Tool calculations, MRW chose to explicitly use one of the externality "slots" to account for this variable.

Land Use. DEG resources, rooftop PV in particular, do not require additional land resources to be installed. This is in contrast to utility scale generation—both conventional and renewable—which require significant acreage to operate. This land could be used for some other purpose from recreation, agriculture or grazing in rural areas, to higher-value users in urban areas (e.g., conventional power plants at Redondo Beach and Huntington Beach). Again, based on the Sierra Club/SEIA analysis of the opportunity costs of alternative use, the land use externality can be monetized at $0.002 per kilowatt-hour.

Other Externalities. While not monetized in this analysis, other externalities associated with central station power production exist. Some examples of this include:

- **Job creation and economic development.** Numerous studies have suggested that solar and other DEG create jobs and contribute to local and regional economic development. For example, a study for the Massachusetts Department of Energy Resources estimated that 69 job-years were generated by each megawatt of solar DEG.[24] Another study estimated the economic development value of soar DEG in the mid-Atlantic region to be around 4¢/kWh.[25] While both of these studies consider east coast locations, some degree of economic development should be expected from California DEG.

B. NEM Cases Modeled

MRW modeled seven cases using the Public Tool and revisions described above. These cases are summarized in Table 6. The first three cases represent TASC's August 3, 2015 Proposal, modeled with the three residential rate designs specified in the July 20 ALJ ruling. The next case is the TASC Proposal with DEG customers paying the non-bypassable charges (NBCs) based on their gross consumption. Specifically, the "Other" nonbypassable flag was set so that the DEG user paid the "other" nonbypassable rate elements (e.g., Public Purpose Program, CTC, DWR Bond Charge, Nuclear Decommissioning Charge) for their gross use. While the Public Tool includes flags to make T&D and generation rate elements nonbypassable, they were not selected.

[24] La Capra Associates, et al, "Task 3b Report: Analysis of Economic Costs and Benefits of Solar Program." Prepared for the Massachusetts Department of Energy Resources. September 2013.

[25] Norris, Benjamin and Thomas E. Hoff (Clean Power Research), "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," prepared for Mid-Atlantic Solar Energy Industries Association and Pennsylvania Solar Energy Industries Association. November 2012.

The next case explores the impacts of setting the minimum residential monthly bill (MB) at $15, and the sixth is the TASC Case with a $10 residential fixed charge (FC). The last case represents a high renewables case: the RPS requirement is at 50%, no renewable curtailment, and the renewable energy credits (RECs) generated by the DEG systems count towards meeting host IOU's Bucket 1 RPS requirements.

As noted, the actual TASC Proposal presented in its August 3, 2015 filing in R.14-07-002 is for DEG customers to pay Public Purpose Program charges based on their gross consumption. Therefore, the results for the actual TASC Proposal will fall between the "TASC Case" and the "NBC Case."

Not all of these cases will be discussed in every context. In general, the sensitivity cases will be compared, as appropriate, against the TASC Case.

Table 6. Public Tool Scenarios

Case	DEG pays NBCs	RPS Requirement	DEG REC Treatment	Residential Minimum Bill	Residential Fixed Charge	Residential Rate
TASC Case		33%	Default	$10		2-tier
TASC Case		33%	Default	$10		Narrow TOU
TASC Case		33%	Default	$10		Wide TOU
NBC Case	✓	33%	Default	$10		2-tier
MB Sens.		33%	Default	$15		2-tier
FC Sens.		33%	Default		$10	2-tier
High RPS		50%	Bucket 1	$10		2-tier

The High renewables sensitivity case contains two assumptions that require additional explanation: That RECs generated by DEG can be counted as "Bucket 1" for IOU's RPS compliance purposes; and the assumption there is no curtailment of utility-scale renewables.

A large reason for including the High Renewables Case is Senate Bill (SB) 350. This bill, authored by Senate President Pro Tem Kevin De Leon, essentially codifies the Governor's clean energy goals announced in his 2015 State of the State address. A major element of the Bill is to raise the RPS requirement from 33% to 50% by January 1, 2030. SB 350 currently resides in the Assembly Appropriations Committee and is expected to pass by August 28.

With respect to assuming no curtailments under a 50% RPS, a number of potential mechanisms exist through which renewable curtailments can be avoided. Based on previous E3 studies, the draft Public Tool contained hard-coded renewable curtailments, and thus did not account for these mechanisms. At the request of parties in their written comments on the draft Public Tool, E3 added the option to disable these curtailments. MRW used this option when modeling the TASC High Renewable case.

The primary reason for providing the no-curtailment option is the existence of the CAISO's Energy Imbalance Market (EIM), which makes available the potential to integrate higher levels of renewable energy across the West without causing the reliability or over-generation problems. A recent FERC Staff Paper emphasized that, "An EIM can aid in the reliable integration of renewable resources, especially by allowing a more diverse set of resources to be redispatched from a wider area in response to imbalances."[26] Similarly, the Western Electricity Coordination Council (WECC) Efficient Dispatch Toolkit states, "an EIM could automatically locate and dispatch a wider array of available resources to regain system balance with changing variable energy resource output, and may prevent some curtailments of variable energy resources."[27]

The common EIM between CAISO and PacifiCorp is occurring, with NV Energy planning to participate in the CAISO's EIM later in 2015, and Arizona Public Service and Puget Sound Energy plan to enter in 2016. This vast area across the West represents significant diversity in both load and resources. The improved visibility and forecasting of renewable generation output that this market creates, as well as the optimization of resource dispatch, and lower sensitivity to resource outages due to enhanced coordination, will go a long way towards minimizing curtailments of renewable generation.

In addition to the EIM, CAISO is currently leading a stakeholder initiative that is intended to establish a new capacity product for downward ramping flexibility, with the goal of Board approval in 2016 and implementation in 2017. The new flexible capacity product will be designed to fulfill the CAISO's "growing need for downward flexible capacity to address over-generation", and thus will significantly reduce existing forecasts of renewable energy generation curtailment, which were conducted without considering implementation of standardized

[26] Federal Energy Regulatory Commission Staff Paper: Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market (February 26, 2013). Available at: https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf
[27] Western Electricity Coordinating Council, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," at 12-13 (October 11, 2011)

downward flexibility products. [28] It should also be noted that California's energy storage mandate and higher electric vehicle penetration with smart charging will similarly contribute to managing the curtailment challenge.

C. Solar Market Growth Metric Results

Continued and sustainable growth in renewables is a key metric. Table 7, below shows annual average growth in DEG capacity in megawatts and percent, along with the 2025 total renewable DEG capacity added. The first four rows show the results for the TASC Case, the NBC Case, the $15 MB Case, and the High Renewables Case. The TASC Case and the NBC Case are nearly identical, differing only by 2 MW per year of DEG growth. From this, one can infer that the full TASC Proposal (with non-bypassable PPP) can be approximated by either the TASC Case or the NBC Case.

The $15 minimum bill case is lower, with a growth rate about one percentage point lower than the first two cases, which results about 150 fewer megawatts of DEG in 2025. As one would expect, the High Renewables Case has the largest growth in DEG, with a growth rate 0.4 percentage points greater than the TASC Case resulting in nearly 500 more megawatts of DEG in 2025.

For comparison purposes, the Public Tool's DEG growth for 2012-2016 is included. Since the statutory requirement is for continued sustained growth, the DEG growth in the four modeled cases can be compared to this historic baseline. At 46% per year growth, on a percentage basis the 2012-2016 growth rate is over four times that of any of the modeled cases. However, expecting market growth to continue at a compound rate of 46% is clearly not reasonable. Thus, to assess the "continued sustained growth" criterion, one can compare the absolute growth in megawatts in the historic period to that in the forecast periods. When viewed from this perspective, all the modeled cases are on the same order of magnitude as the megawatt growth in the historic period. As such, these NEM policies can reasonably be assumed to pass the continued sustainable growth criterion.

[28] https://www.caiso.com/Documents/Agenda_Presentation_FlexibleResourceAdequacyCriteria_MustOfferObligations_WorkingGroup.pdf

Table 7. DEG Growth Statistics (2016-2025)

Case	Ave. DEG Capacity Growth, %/year	Ave. DEG Capacity Growth, MW/year	Total DEG Capacity in 2025[29], MW
TASC Case	11.1%	871	12,022
NBC Case	11.1%	873	12,035
$15 MB	10.9%	854	11,865
High Renewables	11.5%	925	12,503
2012-2016 (per Public Tool)	*46%*	*764*	*n/a*

D. Benefit-Cost Metric Results

As discussed above, the benefit-cost metrics that reflect the legislatively-mandated criteria are the Participant Cost Test (PCT), the Total Resource Cost Test (TRC), and the Societal Cost Test (SCT). Table 8 shows the PCT benefit-cost ratios for the TASC Proposal using the three required residential rate designs. The table clearly shows that all three cases are positive overall as well as for both the residential and non-residential classes. It also shows that the PCT benefit cost ratios diverge little. Given the uncertainties in the inputs to the Public Tool, for practical purposes one should call them all equivalent.

Although not shown here, the results of the other benefit-cost metrics are also approximately the same for the three differing residential rate designs.

Table 8. Participant Cost Test Benefit-Cost Ratios (TASC Case)

Case	All Classes	Residential	Non-residential
2-Tiered	1.42	1.38	1.56
TOU narrow	1.48	1.45	1.56
TOU wide	1.42	1.37	1.56

Table 9 and Table 10 show the benefit-cost ratios according to the TRC and SCT tests for the TASC Case, the NBC Case, the sensitivity with a $15 minimum bill, and the High Renewables case. For both tests, the benefit-cost ratios for the cases where only the residential rate design is changed are, for practical purposes, identical. Given that neither of these two tests specifically account for rate savings or rate impacts, this result should not be surprising.

The TRC benefit-cost ratio for the High Renewables case is significantly greater than the cases based on the TASC Proposal. This savings is caused at least in part by the Bucket 1 treatment of the DEG RECs: with DEG being able to fully offset utility-scale renewables, each kWh of DEG

[29] Including capacity from grandfathered DEG.

generation is can now avoid significantly more costs than they could without Bucket 1 treatment. The assumption of no renewable curtailment also contributes, as "free" (i.e., no variable cost) energy does not have to be forgone for grid management purposes.

Table 9. Total Resource Cost Test Benefit-Cost Ratio

Case	All Classes	Residential	Non-residential
TASC Case	1.20	1.18	1.25
NBC Case	1.20	1.19	1.23
$15 MB	1.20	1.19	1.25
High Renewables	1.47	1.45	1.45

Table 10. Societal Cost Test Benefit-Cost Ratio

Case	All Classes	Residential	Non-residential
TASC Case	1.51	1.49	1.57
NBC Case	1.51	1.49	1.56
$15 MB	1.51	1.50	1.58
High Renewables	1.50	1.48	1.48

The difference in the SCT benefit-cost ratio between the TASC Proposal and the High Renewables case is minimal. This is due to the drastic reduction in fossil generation in the High Renewable case, reducing the various pollutants and impacts associated with fossil fuels, and to a lesser degree, the differing discount rate.

While MRW believes that the Rate Impact Measure (RIM) test should be at most an advisory criterion for evaluating energy policy options, the RIM benefit-cost results are included here for perspective. Table 11 shows the results for these same four cases under the RIM test. For each case, two RIM benefit-cost ratios are shown: one when the impact of the reduced behind-the-meter load is included in the calculation and one where only the value of the exported DEG energy is included. In all four cases, the RIM benefit-cost ratios are on the order of 0.8 to 1.0. The cases with the lowest RIM results are the two with Residential Rate sensitivities, with benefit-cost ratios at or slightly below 0.8. The High Renewables case causes the least rate impact, with benefit-cost ratios of 0.9-1.0.

Table 11. Rate Impact Measure Test Benefit-Cost Ratio
Overall/Export Only

Case	All Classes	Residential	Non-residential
TASC Case	0.85/0.80	0.86/0.80	0.83/0.80
NBC Case	0.87/0.80	0.88/0.79	0.85/0.84
$15 MB	0.86/0.80	0.87/0.79	0.83/0.84
High Renewables	1.00/0.94	1.00/0.92	1.00/0.92

E. Rate Impacts

As noted earlier, examining the absolute changes in retail rates can be instructive when considering potential impacts on ratepayers. Figure 2shows the impact on residential rates of the TASC full retail credit case (TASC Case) as a proxy for the TASC Proposal. According to the Public Tool, in 2030, the TASC Proposal would increase residential rates for PG&E and SCE by $0.006/kWh (~3%) and SDG&E by $0.010/kWh (~4%). These percent differences are maintained through 2050. The results for non-residential rates are similar: all three IOUs rates are about 3%-5% greater with the TASC Proposal than the Public Tool's assumed baseline. However these impacts are overstated, given that a number of real avoided costs (discussed above) are not quantified in this analysis.

Figure 2. Residential Rate Impacts for the TASC Proposal

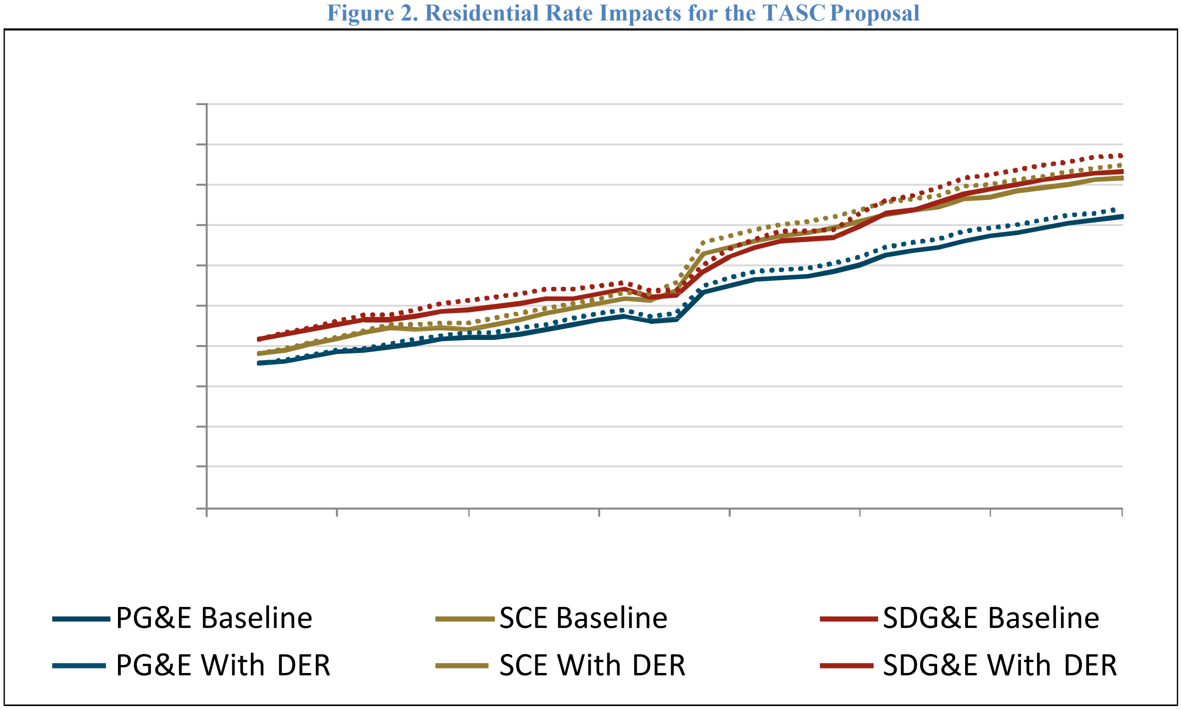
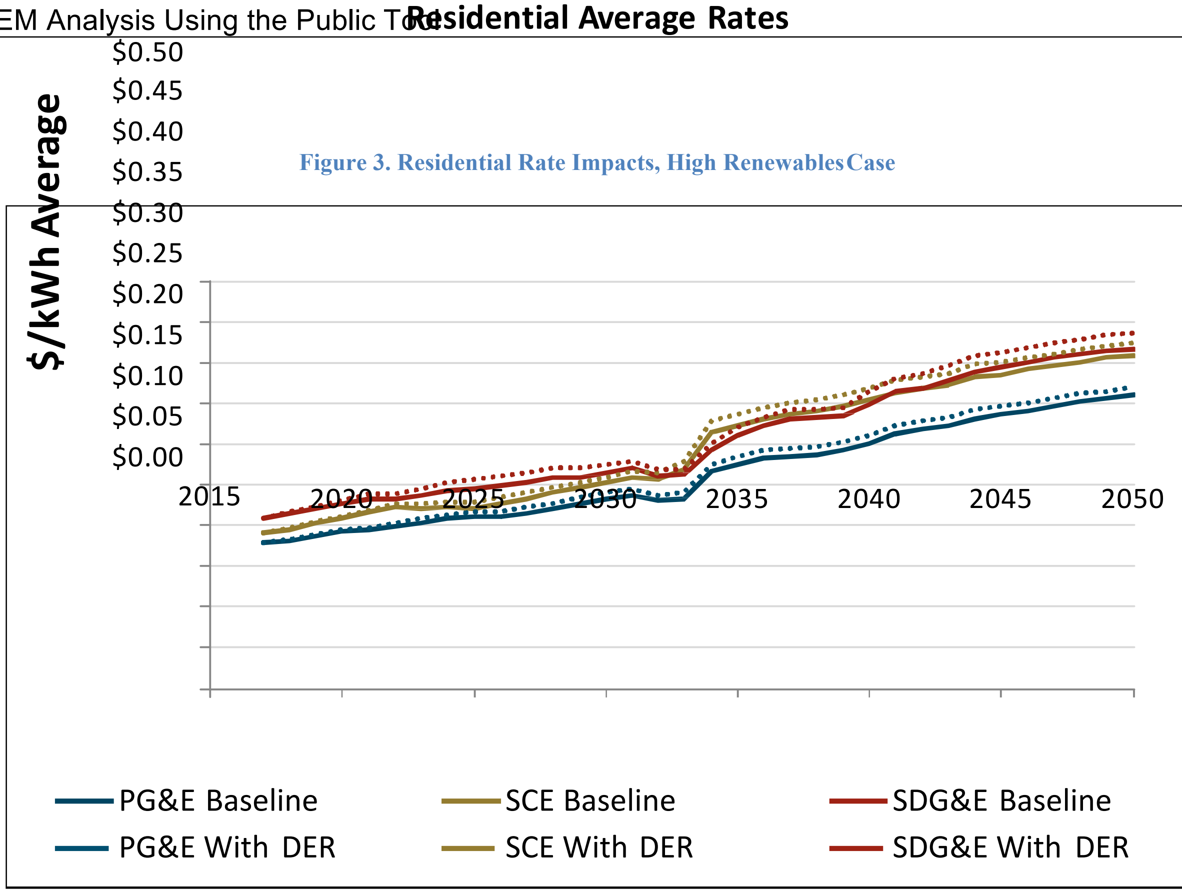


Figure 3 shows the Public Tools' residential rate projections for the High Renewables Case. In 2030, the Public Tool projects that High Renewables case would increase residential rates for all three IOUs by $0.001/kWh (~3.5%-4%). These differences would slowly increase to where in 2050 the difference between the model's no DEG case and the High Renewables Case would be 4.5% to 5.7%. Similar differences and trends are seen for the non-residential classes. Again, these impacts are overstated, due to the absence of certain avoided costs.

Figure 3. Residential Rate Impacts, High Renewables Case



Another way to look at the financial impacts of DEG is to consider the change in the utility's revenue requirement caused by DEG. This is shown in Table 12, below. As the table shows, the impacts are all under 1%.

Table 12. Change in Revenue Requirement Attributable to NEM Export Credits

Case	All Classes
TASC Case	0.72%
NBC Case	0.69%
$15 MB	0.70%
High Renewables	0.28%

V. CONCLUSION

The Public Tool breaks new ground for analyzing distributed generation. It provides immense flexibility by allowing users to input different DEG characteristics, retail rates, rate structures, avoided costs, certain revenue requirement parameters, and discount rates to name but a few. However with that complexity and comprehensiveness comes uncertainty and false precision. Because it so large and complex, the less skilled user can easily place more confidence in the results than is warranted. Much of the default data are based on the model designer’s judgment for values that other knowledgeable parties including MRW, find questionable. For parties and individuals experienced in DEG technologies, California energy policy, and CPUC ratemaking, there areas of the model that simply cannot be vetted or verified. Of equal concern is the fact that some key variables are not obvious. For example, the selection of which rate allocation method is used, a selection that is made hundreds of rows down in a sheet in the Revenue Requirement Model, can have a profound effect on the results, making a successor tariff cost-effective, or not, depending upon the user’s selection.

This is not to detract from the value that the Public Tool can provide in analyzing DEG policy; it is a very impressive tool. Rather, it is to place its use and usefulness in perspective. Policy-makers and analysts may be tempted to rely upon models such as the Public Tool because they generate very specific and precise answers: “This is what the model says.” However all models are only as accurate as their data. Model outcomes based on uncertain inputs are uncertain, even if the results are show to four decimal places.

With all appropriate caveats in place, based on analysis using the Public Tool, MRW finds continued NEM in California can meet the three key criteria set out in AB 327: (a) allow customer DEG to continue to grow sustainably; (b) that the tariff be based on the costs and benefits of the DEG; and (c) that the benefits of the successor tariff to all customers approximately equal the costs. With respect to the first criterion, NEM growth, on a megawatt per year basis, DEG growth is modeled to be on the same order as that which the industry has experienced in the past four years. Second, an NEM tariff can reflect the costs and benefits of the DEG, as customers can experience positive benefit-cost ratios. Third, the benefits of an NEM tariff to all customers can equal, or exceed, the costs. This is shown by the positive benefit-cost ratios in the Total Resource Cost test and the Societal Cost Test. Even if one applies that more stringent Rate Impact Measure test, the benefit cost ratios are between 0.8 and 1.0. Given the minimal weight the Commission places on the RIM test in evaluating energy policies such as energy efficiency and demand response, coupled with the facts that the ratios are within 20% of parity and broader societal impacts are not accounted for, the legislative directive that benefits approximately equal costs for all customers can be met.

These results, along with any other outputs from the Public Tool, must be viewed in light of its inherent limitations and uncertainties. The fact that the metrics for NEM are positive using the Public Tool cannot be taking in isolation: other benefits (and costs) such as increased local and statewide economic activity, environmental benefits and customer choice must also be taken into consideration when forming the successor tariff to the current NEM in California.