**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)

COMMENTS OF THE ALLIANCE FOR SOLAR CHOICE, SOLAR ENERGY INDUSTRIES ASSOCIATION, CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR ON PARTY PROPOSALS

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

Statutes

Cases

Decisions of the California Public Utilities Commission

TABLE OF AUTHORITIES
(continued)

Page

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COMMENTS OF THE ALLIANCE FOR SOLAR CHOICE, SOLAR ENERGY INDUSTRIES ASSOCIATION, CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION AND VOTE SOLAR ON PARTY PROPOSALS

Pursuant to the *Assigned Commissioner's Ruling Granting in Part Motion of The Alliance for Solar Choice and Revising Procedural Schedule* issued June 23, 2015, The Alliance for Solar Choice (TASC), Solar Energy Industries Association (SEIA),[1] California Solar Energy Industries Association (CALSEIA) and Vote Solar (hereinafter Joint Solar Parties or JSPS), submit the following comments on party proposals on the net energy metering (NEM) successor tariff submitted August 3, 2015. The Joint Solar Parties have chosen to focus primarily on the proposals of the investor-owned utilities (IOUs), The Utility Reform Network (TURN), the Office of Ratepayer Advocates (ORA) and the Natural Resources Defense Council (NRDC), as well as the illustrative NEM proposals in the June 3, 2015 "Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract" (Staff Tariff Report) and the proposals for disadvantaged communities in "Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327" (Disadvantaged Communities Staff Paper). Due to limited time and resources, the Joint Solar Parties have not responded directly to other party proposals. Accordingly, silence by the Joint Solar Parties with respect to specific components of parties' proposals should not be interpreted as acceptance of those components of those proposals. Moreover, in an effort to be concise as possible, the Joint Solar Parties have

1 The comments contained in this filing represent the position of the Solar Energy Industries Association as an organization, but not necessarily the views of any particular member with respect to any issue.

addressed the above proposals by issue rather than duplicating comments that are relevant to multiple parties' proposals.

EXECUTIVE SUMMARY

In the following comments, the Joint Solar Parties show that the IOUs and other parties use flawed inputs and assumptions to arrive at their net metering successor tariff proposals. Their proposals would dramatically shrink the rooftop solar industry in California, costing the state tens of thousands of jobs and billions of dollars of economic stimulus while frustrating California's efforts to fight climate change and build a robust clean technology sector.

These comments show that the IOUs' and other parties' flawed proposals stem from an incorrect interpretation of state law and policy. For instance, while state law requires the successor tariff to ensure the solar industry continues to grow sustainably, the IOUs put forth proposals that are specifically designed to impede solar growth rates. Their failure to interpret the statute correctly is compounded by an array of flawed input assumptions that severely discount the values that distributed solar provides to utility customers and society, while vastly overestimating how much solar would be installed under their proposals. Among the incorrect assumptions employed by the IOUs and others in their analyses are the following:

- Overly-optimistic future solar cost declines;
- Inflated projections of utility rate increases;
- Solar system sizes that do not match real-world experience;
- Inflated utility cost assumptions;
- Failure to include avoided transmission and distribution benefits;
- No locational benefits;
- Incorrect application of non-residential rates;
- Assumptions that the societal benefits of clean distributed energy are zero; and
- No consideration that RPS targets would need to increase to meet long-term state climate goals in the absence of rooftop solar.

The IOUs and other parties also incorrectly interpret the requirement that the costs and benefits of the successor NEM tariff are to be roughly equal for "all ratepayers and the electric system." Instead of looking at NEM from the perspective of "all ratepayers," the IOUs and other parties choose to look only from the perspective of ratepayers who do not install solar. By employing a cost-effectiveness test that is rarely used to evaluate other demand-side energy programs and that is nearly impossible to pass, the IOUs all but assure that the NEM successor tariff will dramatically undercompensate rooftop solar customers. This mistake is compounded by the fact that the IOUs assign no value to the benefits rooftop solar provides to the distribution grid – despite the fact that the Commission is considering ways to maximize those benefits in two separate proceedings, and the utilities themselves recognized in those proceedings that net-metered systems can provide significant benefits to the distribution system.

As a result of their incorrect assumptions and flawed interpretation of California law and policy, the IOUs and other parties put forth proposals that would severely damage the continued uptake of customer-sited renewable distributed generation (DG) in California. After correcting for these flawed assumptions, the Joint Solar Parties show that each of the proposals by the three IOUs would curtail solar market growth to significantly below current levels, costing the state thousands of jobs. The JSPSs further point out that the IOUs' proposals would damage the California solar industry even more than the model predicts by proposing complex and confusing rates, introducing significant uncertainty that would impair customers' ability to predict savings and make the long-term decision to go solar. To support this conclusion, the Joint Solar Parties provide data from other utilities that have already implemented changes like the ones the California utilities are proposing. Solar application data from Salt River Project shows that introducing residential demand charges, increased fixed charges, and reduced bill credits – changes similar to the ones the California IOUs are proposing – caused applications for new solar interconnection to decline by 94 percent, effectively killing what was once a robust market in the state with the nation's best solar resource.

The Joint Solar Parties show that the economic impacts of the IOUs' proposals would be significant. To estimate the local economic effect of net-metered solar, the Joint Solar Parties employed Economic Development Research Group (EDR Group) to study the economic spillover and job creation benefits of the distributed solar industry. EDR Group concludes that the TASC scenario (where NEM is continued with minor changes) provides the largest annual job impact with approximately 14,300 California jobs created annually, and 457,300 jobs created over the 2017-2049 period studied. The TASC scenario also provides the most positive gross state product (GSP) impact, approximately $1.5 billion annually, and over $49.5 billion (in

2014$) over the 2017 – 2049 period. By contrast, proposals of the IOUs and other parties would significantly reduce those benefits. Even more important, today it is California companies that are the leaders in exporting the success of this clean energy technology to other states and countries. This Commission should not take actions that would imperil the growth of this critical industry in its home state and largest market.

I. INTRODUCTION

California's Million Solar Roofs initiative was a long-term plan to develop a self-sustaining rooftop solar energy industry. The cornerstone of the Million Solar Roofs initiative was the California Solar Initiative (CSI), the centerpiece of which was $2.4 billion in rebates to solar customers. The vision embodied in that plan was for solar energy to become "a viable mainstream option for both homes and businesses."[2] As that goal now comes within reach, the Commission should celebrate its successes and reaffirm its commitment to maintaining that achievement. The long-term investment in advancing clean energy goals by California's utility customers, the state, the Commission, customers who have invested in DG resources, and other stakeholders was not intended to create temporary progress. Instead, these initiatives are now central elements in the state's ambitious long-term plans to reduce its greenhouse gas (GHG) emissions. If the success of the CSI is to serve as a continuing foundation for achieving the state's clean energy goals, the Commission must ensure that viable market mechanisms for rooftop solar remain in place beyond the CSI target so that solar will continue to be a viable mainstream option. To assist the Commission in developing a successor tariff that builds upon this success and achieves state policy goals, the Joint Solar Parties use well documented assumptions to demonstrate that the current successful framework of net energy metering does not need any fundamental change.

Unfortunately, proposals from the other parties analyzed by the JSPSs for the purposes of these comments do the opposite. They react to the success of the CSI by proposing dramatic changes to the current policy framework supporting customer-sited renewable DG that would significantly curtail the viability of distributed solar energy. These parties use incorrect inputs to the Public Tool to create the appearance that change is needed immediately. Collectively, these

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2 *See,* Senate Bill 1 (2006).

proposals are based on misplaced policy concerns, flawed methodologies, and incorrect legal foundations. Specifically, these proposals saddle solar customers with discriminatory new fees, force residential solar customers to use specific and complex rates without giving them the options available to other customers in their rate class, underpay them for the clean energy they export, and force them to pay rates based on their consumption before they reduced their utility purchases by installing solar. One proposal would take away customers' basic legal right to consume the energy they produce onsite using their own private property. As explained in these comments, each of these actions are unnecessary to meet the requirements of Public Utilities Code Section 2827.1(b) and will undermine the continued growth of customer-sited DG in direct contravention of the requirements of Public Utilities Code Section 2827.1.

To demonstrate this point, the Joint Solar Parties use well-documented assumptions to show that the proposals of the IOUs and other parties would entirely fail to satisfy the statutory mandate "that customer-sited renewable distributed generation continues to grow sustainably" under the successor tariff, and would shift costs from non-solar customers to solar customers by offering proposals that have Ratepayer Impact Measure (RIM) results greater than 1.0. As demonstrated in the successor tariff proposals of the JSPSs, there is no need to change the NEM tariff in the near term, and benefit-cost test results show that a continuation of NEM would satisfy AB 327, the statutory basis for the NEM successor tariff. The net benefits of continuing NEM are particularly impressive when considering the societal benefits of clean, distributed generation – benefits which the JSPS have quantified and which affirm the long-term wisdom of the state's substantial investment over the last decade in transforming this industry. Moreover, macroeconomic analysis conducted by EDR Group concludes that <u>the successor tariff proposals of the solar parties would create significant job opportunities and economic growth relative to the proposals of other parties</u>. These significant economic development impacts benefit all Californians and must be taken into account by decision makers.

II. OPPOSING PARTIES FUNDAMENTALLY MISCONSTRUE CALIFORNIA AND FEDERAL POLICY REGARDING CUSTOMER-SITED DG

As the Joint Solar Parties' proposals collectively explained, since the enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA), California has consistently reformed law and policy to remove barriers to customer-sited renewable DG. The state has done so in order to secure numerous benefits for the utility grid and energy consumers, including load reduction at end use sites, diversity in fuel and generation resources, and customer choice.[3] These market transformation efforts have been an unparalleled success with well over 200,000 customer-sited NEM DG installations in the three large IOUs' service territories and the California solar industry now employing more workers – 54,000 plus – than the state's five largest electric utilities combined. Despite the Commission's and Legislature's consistently expressed policy preference for increased demand-side options for consumers, the proposals submitted by the IOUs, TURN and ORA show a fundamental misunderstanding of the value that customer-sited DG brings to the electric grid and to society. These views are at odds with long-standing Commission efforts to enable customers to control their energy use through demand-side programs.

For example, ORA argues that customer-sited DG should be compared to utility-scale solar, stating, "[t]here is a wide disparity between the cost to ratepayers of residential NEM solar in juxtaposition to comparable-sized competitively-procured solar."[4] ORA's juxtaposition of utility-scale and customer-sited renewable DG is simply not useful in assessing how to build the sustainable customer-sited renewable DG industry required by Section 2827.1. Utility-scale renewables and DG use similar technologies (solar and wind), have similar output profiles, and obviously produce many of the same environmental benefits, including reductions in GHG emissions. However, utility-scale renewables and customer-sited renewable DG are two fundamentally separate and distinct products delivered at different places on the grid, with significantly different benefits and costs for ratepayers and the utility system. Utility-scale renewables sell wholesale power to the utilities; DG directly serves the retail loads of end-use customers. The cost of utility-scale solar discussed by ORA does not include the cost of the

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3 *See, e.g.,* Cal. Pub. Util. Code § 2827(a) ("The Legislature finds and declares that a program to provide net energy metering combined with net surplus compensation, co-energy metering, and wind energy co-metering for eligible customer-generators is one way to encourage substantial private investment in renewable energy resources, stimulate in-state economic growth, reduce demand for electricity during peak consumption periods, help stabilize California's energy supply infrastructure, enhance the continued diversification of California's energy resource mix, reduce interconnection and administrative costs for electricity suppliers, and encourage conservation and efficiency."); See also D.06-01-024 at p. 4 (The objectives of these existing programs, and the one we adopt today, are to add clean energy to peak demand resources, to reduce risk by diversifying the state's energy portfolio, and to reduce the demand for transmission and distribution system additions.").

4 ORA Proposal, p. 4.

transmission system upgrades necessary to bring utility-scale renewable energy to end-use customers, nor does it consider that, by serving on-site loads directly, DG can allow the utility to reduce its load-related transmission and distribution (T&D) costs. ORA's comparison also does not include other benefits of DG that utility-scale projects cannot provide, including reduced line losses, fewer land use impacts, enhanced reliability and resiliency, greater local economic activity, or lower congestion costs. Thus, in the end, ORA's comparison is simply without merit.

Other parties attempt to frame the discussion as a battle between "haves" and "have nots," arguing that fairness to non-participating ratepayers demands a radical departure from the current system of net energy metering and well-established Commission rate design methods. In doing so, these parties fail to recognize the state's substantial progress in making distributed solar a mainstream option: as solar prices fall, financing becomes more widely available, and the Legislature and Commission continue to reform laws and to adopt new policies and programs – such as Green Tariff Shared Renewables, NEM aggregation, virtual net metering, and the disadvantaged communities portion of AB 327 – to *increase* access to renewable energy resources for all customers regardless of economic circumstances. The Commission has also reduced significantly the impacts of net metering on non-participants by reforming residential rates to flatten inclining block rate tiers, require higher minimum bills, and set a path toward default time of use (TOU) rates for residential customers.[5]

These parties support their views by raising concerns about a purported cost shift from NEM customers to non-participating customers. However, these cost shift arguments are founded on inaccurate modeling. Moreover, distributed generation is a demand-side resource like energy efficiency, and should be evaluated in the same way – focusing on the overall benefits and costs of the program, rather than on differences between participants and non-participants. The proposals of other parties to radically alter or end NEM are based on incorrect views about how the RIM test has been utilized by the Commission in comparable reviews of other demand-side management (DSM) programs. Despite deep involvement from TURN, ORA and the IOUs in the proceeding leading to Decision (D.) 09-08-026, which addressed DG cost-effectiveness methodologies, they continue to seek to relitigate an issue that has been settled for over 6 years – the RIM test is not the primary source of review when considering demand side management

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5 *See* Decision 15-07-001.

programs. Conclusion of Law in D.06-08-026 was crystal clear: "The Commission should not require the use of the RIM Test to evaluate DG programs because it is not relied on to evaluate energy efficiency programs."[6]

In prior reviews of energy efficiency programs, the Commission has routinely approved energy efficiency programs with RIM test scores below 1.0 when the overall portfolio of programs has a Total Resource Cost (TRC) test score above 1.0. Thus, these parties would have the Commission go against well-established Commission practice concerning cost-effectiveness standards for demand side resources, and would establish a double standard concerning review of NEM that is not consistent with past Commission statements that all DSM programs should be reviewed in a similar manner. The parties' views on the RIM test are also not consistent with the actual language of Public Utilities Code Section 2827.1(b), as has been noted numerous times by the Joint Solar Parties individually and collectively.

In reality, empowering customers to make choices about how they consume energy is essential to ensuring California's greenhouse gas goals are met at the lowest possible cost. As the Commission's Policy and Planning Division stated in its white paper *Customers as Grid Participants: A Fundamentally New Role for Customers*, "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."[7] As the Joint Solar Parties collectively explained in their proposals,[8] the importance of NEM to solidify market transformation in the face of losing a key federal tax credit cannot be overstated: NEM is simple and easily understood by customers,

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6 *See* D.09-08-026, Conclusion of Law No. 3, p. 58.

7 See *Customers as Grid Participants: A Fundamentally New Role for Customers* (May 2013), at p. 3, California Public Utilities Commission Planning and Policy Division, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/A0A816A2-9F1C-4F34-90DB-C23551F09738/0/PPDCustomerRoleMay15th.pdf.

8 TASC Proposal, p. 13 (citing Navigant Consulting, California Solar Initiative Market Transformation Study (Task 2) (2014) at p. 13, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/C0AC3B34-2321-49FC-8351-63B290E943E/0

9 CSIMTStudyTask2ReportFinalFinalCLN20140425.pdf (calling NEM "instrumental in helping to drive the market for distributed solar PV in California"); SEIA / Vote Solar Proposal, pp. 3-7; CALSEIA Proposal, pp. 5-7.

provides certainty to participants, and has been a consistent part of California solar DG policy for over 20 years.[9]

The fact that certain parties are misconstruing California and federal policy regarding customer-sited DG is also evident in their proposed definitions of “sustainable growth.” These parties misinterpret the language of the statute that is clearly concerned with continuing the growth of customer-sited renewable generation.[10] For example, SDG&E erroneously defines “sustainable growth” as “a process that allows all customers to participate in the NEM program without negatively impacting non-participating customers, either by shifting costs to non-participating customers or putting at risk the safety and reliability of the grid.”[11] Conspicuously absent from this definition is any concern with whether the successor tariff actually will result in continued growth in customer-sited renewable DG as required by Public Utilities Code Section 2827.1(b)(1). Whiles SCE acknowledges that there should be some growth, it implies that any number of installations would constitute growth by stating, “growth need not be ‘robust.’”[12] This interpretation clearly contradicts any reasonable understanding of what the Legislature meant by “sustainable growth” as it does not consider historic installation rates, which the Legislature is clearly aware of through the use of the word “continues” in the sentence and which the customer-sited renewable DG industry is clearly built to support at this point in time. Efforts to interpret the language otherwise are merely flawed attempts to ignore AB 327’s clear intent that customer-sited generation continue to grow in a sustainable manner. Moreover, in putting forth definitions like these, parties continue to frame the on-going market transformation enabled by customer-sited DG as a problem rather than a solution.

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9 TASC Proposal, pp. 13-14.

10 *See* Cal. Pub. Util. Code § 2827.1(b)(1).

11 SDG&E Proposal, Attachment A, p. A-4.

12 SCE Proposal, p. 11.

III. BOOKEND CASES FROM ENERGY DIVISION STAFF TARIFF REPORT ARE NOT LEGITIMATE SCENARIOS FOR EVALUATING PROPOSALS AND, ONCE DEFICIENCIES IN THE ANALYSIS PERFORMED BY STAFF ARE CORRECTED, SIGNIFICANT DECREASES IN SOLAR ADOPTION ARE FOUND

The Staff Tariff Report presents three policy scenarios and analyzes the impacts on DER adoption and RIM cost test results. The IOUs, TURN and ORA each cite selectively from the Staff Tariff Report in support of their proposals, but their reliance on the Staff Tariff Report is fundamentally misplaced. First, the Staff Tariff Report specifically notes that the scenarios utilized are intended solely "to demonstrate how to use the Public Tool to evaluate one or more successor tariffs/contracts."[13] The Staff Tariff Report was also careful to note that, "By including *illustrative* NEM successor tariff/contract scenarios in this paper, Staff is not intending to recommend or favor a particular scenario."[14] Furthermore, the assumptions used in Staff's analysis are faulty and lead to results indicating inflated adoption rates and high costs to non-participants. Thus, there is no basis for relying on the discussion in the Staff Tariff Report in support of parties' views in this docket.

In their proposals, the Joint Solar Parties provided Public Tool input assumptions that are more accurate and realistic than those in the Staff's bookend cases. Accordingly, the Joint Solar Parties believe the analysis shown in the Staff Tariff Report is fundamentally flawed and cannot be used to assess whether similar proposals would result in continued, sustained growth in customer-sited renewable DG as required under Section 2827.1(b). In this portion of our comments, the Joint Solar Parties provide further support for our key assumptions, apply them one by one to the High bookend scenario of the illustrative proposals in the Staff Tariff Report, and discuss the results. In looking at the numbers in the following tables, it is important to understand that the results are stacked – the end point of introducing one new assumption is the starting point of the next – so the important result for each section is the difference between the "Without Input Change" and the "With Input Change" portions of the table. The results shown in the following tables are for post-2017 installations; they do not include grandfathered systems.

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13 Staff Tariff Report, p. 1-4.

14 *Id.* (emphasis added).

A. Inputs Primarily Impacting Adoption

1. Solar Cost

The Commission must take care not to assume future price reductions that are unattainable. This would happen if the Commission were to find reasonable the numbers in the Public Tool's low solar cost case. The Energy Division's High Renewable DG Value Case uses that case, which results in very high adoption numbers that are not realistic.

a. LBNL Study

In August 2015, Lawrence Berkeley National Lab (LBNL) released its 8th annual "Tracking the Sun" report.[15] This is the most authoritative academic study on solar prices published in the United States and, therefore, is a definitive resource for determining solar costs to customers.[16] The study found that the average all-in cost of solar to California customers in 2014 was $5.29 per AC-watt ($4.60 per DC-watt) for systems smaller than 10 kW.[17] This is 2% higher than the 2014 solar cost in the Public Tool base cost case and 19% higher than the low cost case. Thus, looking backward to last year, the Public Tool is already misrepresenting customer costs significantly in the low cost case.

The 2015 price in the Public Tool low cost case is $3.55/W-AC. This is 49% lower than the actual 2014 price as found by LBNL. A year-over-year price reduction of that magnitude is unfathomable. Based on preliminary data for the first half of this year, LBNL finds that 2015 prices are 8% lower than 2014 prices. If that trend holds for the rest of the year, the 2015 California price will be $4.87/W-AC. To meet the 2016 price in the Public Tool low cost case of $2.87/W-AC, there would have to be a 70% year over year price reduction. Those percentage reductions are so extreme that the Commission must dismiss the results of any Public Tool runs using the low solar cost case.

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15 *See* Barbose, Galen L. and Naïm R. Darghouth, "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Lawrence Berkeley National Lab, August 2015, available at: http://emp.lbl.gov/publications/tracking-sun-viii-install.

16 The "solar cost case" in the Public Tool refers to the cost to customers, including the portion of overhead that solar providers apportion to each installation. The market price tracked by LBNL is the same as this cost to customers.

17 *Id.,* p. 51, using an AC/DC conversion rate of 0.87.

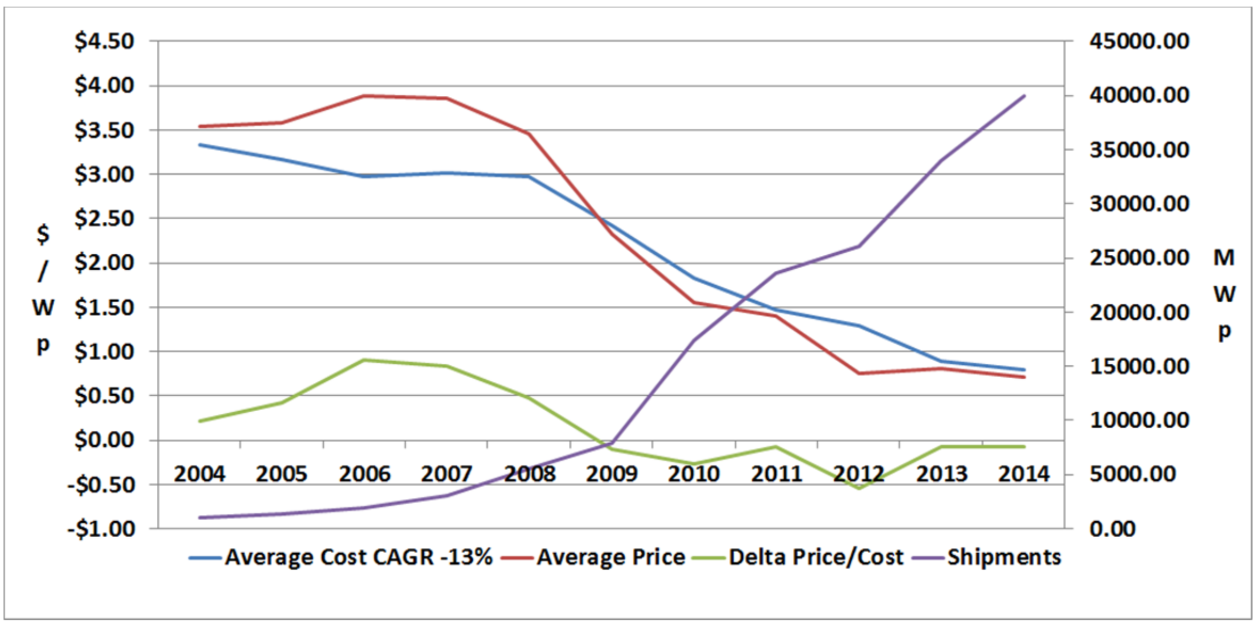
Table 1. Comparison of LBNL Findings With Public Tool Numbers ($/W-AC)

	LBNL	Public Tool Base Case	Public Tool Low Case
2014	5.29	5.17	4.46
2015	4.87 (est.)	4.69	3.55
2016	N/A	4.29	2.87

b. Aggressive Module Pricing

The reduction in module prices in recent years is the result of economies of scale combined with aggressive pricing strategies by module manufacturers seeking market share. Although intense competition is good for the market and will hopefully continue to keep prices low, the aggressive pricing strategies of recent years are not sustainable and should not be expected to continue driving module prices lower. Figure 1 demonstrates that modules have been selling for lower than the cost of manufacturing.

Figure 1. Module Sale Price Compared to Cost of Manufacturing[18]



In the absence of reduced future equipment costs, solar companies must look for cost reductions in labor. The only ways to spend less on labor are to pay people less or to spend fewer hours to accomplish the same results. The first of those is not an option because the quality of

[18] Paula Mints, SPV Market Research, "Global Analysis of Markets for Photovoltaic Products," 2014.

work should not be allowed to diminish and because the growing economy will push average wages higher. The cost of labor per hour should be assumed to go up. Thus, the only way to save on labor costs is to work more efficiently. Some continued improvement on labor efficiency should absolutely be expected, but it would be risky to count on that efficiency growing rapidly and continuously, especially in the face of expected reductions in market activity in 2017 due to the federal investment tax credit (ITC) step-down.

c. Impact on Results

As a general matter, when solar is cheaper, more people will adopt it; when solar is more expensive, fewer people will adopt it. The low solar cost case overstates adoption in the Full NEM case of the Energy Division policy scenarios, by 31% in 2017 and by 20% over the nine years of installations modeled in the Public Tool. In the Value Based Export case and the Modified NEM Credit case, the low solar cost case inflates adoption by 58-59% in 2017 and by 37%-41% over nine years, as shown in Table 2.

Table 2. Impact of Solar Cost Case

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change – Low Solar Cost Case				
Full NEM	1,400	16,047	1.07	0.47
Value Based Export	1,043	11,341	1.15	0.66
Modified NEM Credit	1,075	12,663	1.15	0.63
With Input Change – Base Solar Cost Case				
Full NEM	965	12,795	0.78	0.49
Value Based Export	438	7,161	0.81	0.65
Modified NEM Credit	438	7,491	0.81	0.65

2. Rate Escalation

The Public Tool includes an "Assumed Utility Rate Escalation" input that indicates how much customers expect rates will go up in the future. A higher percentage escalation results in higher projected bill savings, and therefore more people adopting DER. The Energy Division Public Tool runs assume that potential solar customers will expect rates to increase 5% per year in their evaluation of solar economics, even though the Public Tool predicts that rates will rise at less than 3% per year. Average annual rate increases over the past 20 years have been 1.0%-

2.8%, depending on utility and customer class.[19] The Public Tool itself calculates future rate escalation at 2.4%-2.6% in the CALSEIA base case and at 2.5%-2.7% in the Vote Solar-SEIA (VS-SEIA) base case.[20] Any adoption results using 5% as the assumed rate escalation that are incorporated into the decision on the successor tariff would constitute a material, factual error. Using a 5% assumed rate escalation, rather than the 3% assumed rate escalation used by the Joint Solar Parties, inflates forecasted installations by 26%-30% in 2017. Over nine years, it inflates adoption by 16% in the Full NEM case, 10% in the Modified NEM Credit case, and 3% in the Value Based Export case.

Table 3. Impact of Assumed Rate Escalation

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change – 5% per year				
Full NEM	965	12,795	0.78	0.49
Value Based Export	438	7,161	0.81	0.65
Modified NEM Credit	438	7,491	0.81	0.65
With Input Change – 3% per year				
Full NEM	715	10,744	0.79	0.54
Value Based Export	305	6,926	0.87	0.64
Modified NEM Credit	314	6,723	0.85	0.62

3. Adoption Sizes

The adoption model portion of the Public Tool selects a particular DG system size (Small, Medium, or Large) for all installations in a "bin" of similar customers purely on the basis of the best economics, even if another system size has economics that are almost as favorable. The adoption model gives significant weight to the net present value (NPV) of the net benefits of a system, in total dollars, as well as to the benefit/cost ratio for the DG customer. The significant weight given to the absolute magnitude of the NPV of net benefits biases the adoption model in many cases to favor Large systems that will have a significantly higher NPV in dollars just because they are large, even if they have a similar, or lower benefit/cost ratio than Small or Medium systems. For example, the table below shows three residential bins from PG&E's

19 SEIA / Vote Solar Proposal, p. A-1.

20 CALSEIA Proposal, p. 18; SEIA / Vote Solar Proposal, p A-1.

Climate Zones P and S, and the system sizes that result from the unmodified adoption model in the Public Tool. In each of these cases, the model picks a larger system than the historical data on system size for that bin, even though the benefit/cost ratios for smaller sizes are similar to (see Bin 120), or greater than (see Bins 105 and 127), the benefit/cost ratio for the selected size.[21]

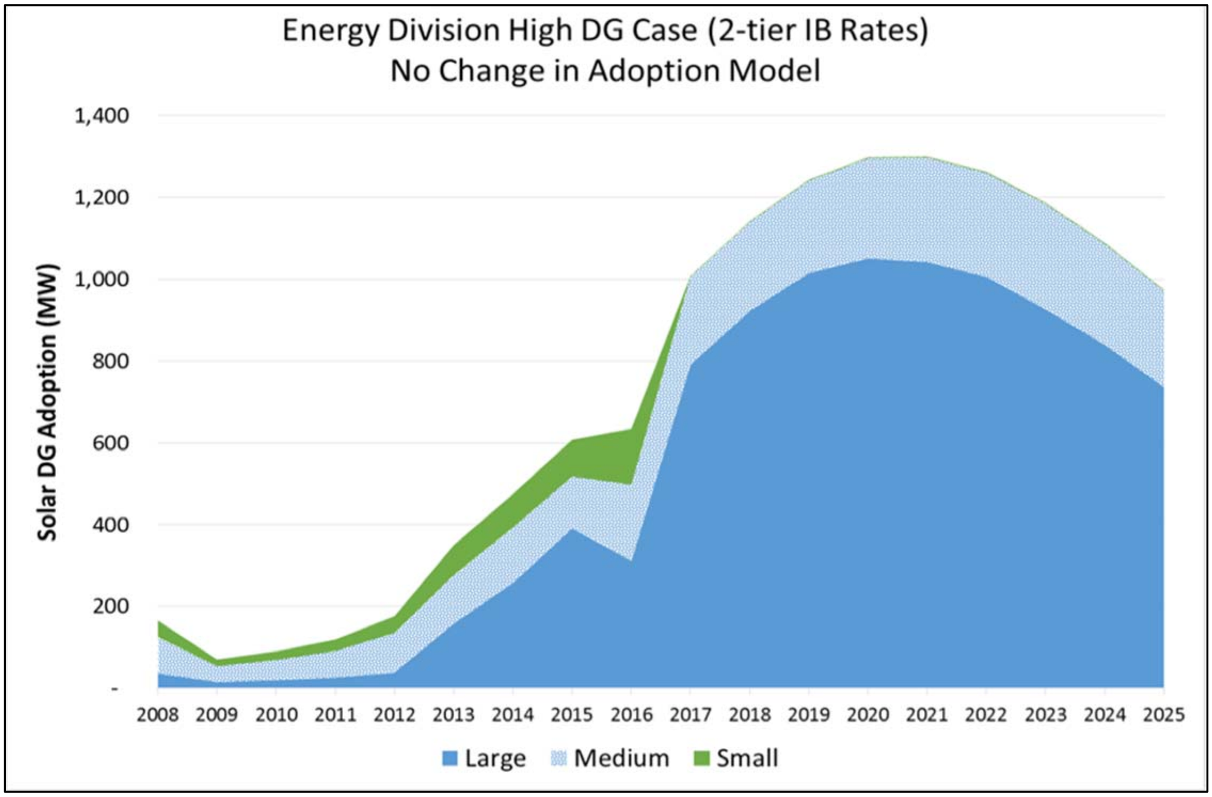
Table 4. Example of Public Tool System Sizing

Adoption Model Results for 2017 -- Unmodified Public Tool -- PG&E Zones P & S (Bins 101-133)													
Bin #	*Historical Size*			*Adoption Module*							*Solar Adoption Results*		
									* excludes storage in this example				
				Size (kW)	NPV Benefit	NPV Cost	B/C Ratio	NPV Net	NPV & B/C Norm Weighted Factor*		Size	Annual Additions (kW)	Annual Additions # systems
	Small	Small	Solar	1.68	$ 7,605	$ 6,102	1.27	$ 1,683	0.90				
105		Med	Solar	3.41	$ 14,933	$ 12,390	1.21	$ 2,543	0.96	<==>	**Med**	3,530	1,036
		Large	Solar	5.09	$ 19,527	$ 18,492	1.06	$ 1,035	0.70				
	Small	Small	Solar	3.31	$ 14,734	$ 12,054	1.22	$ 2,680	0.81				
120		Med	Solar	6.73	$ 28,556	$ 24,472	1.17	$ 4,084	0.84				
		Large	Solar	10.04	$ 38,899	$ 31,753	1.23	$ 7,146	1.00	<==>	**Large**	7,155	712
		Small	Solar	2.51	$ 11,565	$ 9,141	1.27	$ 2,424	0.83				
127	**Med**	Med	Solar	5.10	$ 22,878	$ 18,559	1.23	$ 4,319	0.92				
		Large	Solar	7.62	$ 33,142	$ 27,700	1.20	$ 5,443	0.96	<==>	**Large**	4,258	559

The result is that, in much of the modeling that has been done, a large majority of the DG kWs installed after 2017 are from Large systems that offset 100% of the customer's load. For example, the following figure shows the adopted DG sizes for the Energy Division's High DG bookend with 2-tier increasing block rates.

[21] Obviously, not all bins show the same results as these three; however, this example illustrates the general trend. There are 27 residential bins in these PG&E climates zones. Fifteen (15) of the bins (including the three in the table) showed an increase in system size, 6 bins had no change in system size, and 6 bins showed a decrease in size. Historically, the distribution of system sizes in this climate zone was 44% small, 37% medium, and 19% large. The adoption model in the Public Tool says that this will change to 19% small, 44% medium, and 37% large.

Figure 2. System Size Prediction in the Public Tool



The results shown in this figure for 2017-2025 are very different than the historical distribution of system sizes based on data up to 2012. The Joint Solar Parties submit that this expectation of an overwhelming predominance of Large systems is unrealistic, especially because, for many "bins" of customers, there are only minor differences in the benefit/cost ratios for the customer based on system size, as in the examples above. In the real world, if systems of several sizes offer comparable benefit/cost ratios – in other words, if Small, Medium, and Large systems all offer roughly 20% more benefits than costs – solar customers will consider factors other than economics in deciding how big a system to buy. These other factors include such constraints as available roof space, building orientation, shading, aesthetics, or their limited available ability to finance home improvements. All of these non-economic factors tend to push customers toward smaller system sizes.

The Joint Solar Parties recognize that changes in rate structure will impact the distribution of DG system sizes and that the flattening of tiered residential rates will encourage customers to move away from small systems that only offset the highest tiers of usage, but the adoption model should recognize that other, non-economic factors also will work in the other direction, tempering the degree to which large systems will be selected. As a result, the adoption model should start from an allocation of system sizes based on past experience, which reflects not only economics but also the other constraints on system sizing. To incorporate this, the JSPSs have modified the adoption model to limit the system size adopted for a particular bin of similarly-situated customers to the historical system size for that bin using E3's data through 2012 on the actual system size for each bin. In other words, if a bin was "small" in 2012, it will be "small" in 2017-2025. However, the JSPSs continue to allow the adoption model 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 from 2017-2025, just not to the same extent as the unmodified Public Tool. This change in the Public Tool strikes a better balance between economics alone and the many other factors that will tend to limit system sizing, and produces results that are more reflective of the diversity of system sizes experienced in the field. With this change, the total adoption in MW decreases, as shown in the table below, because more customers will choose small and medium systems, as shown in the table below. The JSPSs also note that this change actually reduces the RIM results in the Full NEM case because smaller systems offset more usage in the more expensive upper tier of rates.

Finally, as requested in the Assigned Commissioner's Ruling dated June 23, 2015 (June 23 ACR), the JSPSs note that this change to the system sizing is a "hard-wired" modification made to the Public Tool. As requested, the following table shows the impact of this modification, showing how the results change between using the unmodified and modified versions of the Public Tool.

Table 5. Impact of Adoption Size Fix

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change – No Fix				
Full NEM	715	10,744	0.79	0.54
Value Based Export	305	6,926	0.87	0.64
Modified NEM Credit	314	6,723	0.85	0.62
With Input Change – With Fix				
Full NEM	601	8,389	0.80	0.51
Value Based Export	423	7,115	0.83	0.64
Modified NEM Credit	433	7,284	0.83	0.63

B. Inputs Primarily Impacting Avoided Costs

1. Utility Cost Errors

The Joint Solar Parties' proposals included two modifications to the Revenue Requirements model that are outside of the fields that were created to allow inputs that differ from the default values. Neither of the changes have major impacts on the overall results. The Joint Solar Parties made these changes despite the fact that they are not major drivers because they appeared to be clear mistakes. First, Diablo Canyon O&M was left in PG&E's generation O&M beyond the date when the plant is scheduled to be closed. Second, the value used for SDG&E generation capital expenses was far different from the value reported in the utility's most recent GRC. Again, as requested in the June 23 ACR, these changes are "hard-wired" modifications made to the Public Tool. As requested, the following table shows the impact of these modifications, showing how the results change between using the unmodified and modified versions of the Public Tool.

The results are minor. By reducing the overall revenue requirement, average rates will decrease, thereby reducing the bill savings and driving adoptions slightly lower, while slightly increasing the RIM result.

Table 6. Impact of Utility Cost Errors

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	601	8,389	0.80	0.51
Value Based Export	423	7,115	0.83	0.64
Modified NEM Credit	433	7,284	0.83	0.63
With Input Change				
Full NEM	599	8,344	0.80	0.52
Value Based Export	421	7,080	0.83	0.64
Modified NEM Credit	430	7,248	0.83	0.64

2. Other Input Changes in the Revenue Requirements Model

The Joint Solar Parties made changes to default values in the Revenue Requirements model in fields that were created to allow alternative inputs, as described in their respective successor tariff proposals. These changes directionally have similar effects as the Diablo O&M change: lower revenue requirement leads to lower average rates, lower bill savings, lower adoption, and higher TRC and RIM.

Table 7. Impact of Revenue Requirement Input Changes

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	599	8,344	0.80	0.52
Value Based Export	421	7,080	0.83	0.64
Modified NEM Credit	430	7,248	0.83	0.64
With Input Change				
Full NEM	576	8,128	0.84	0.54
Value Based Export	417	7,061	0.86	0.65
Modified NEM Credit	410	7,045	0.86	0.65

3. Marginal CAISO High-Voltage Transmission Costs

The Energy Division bookend scenarios assume that DG, by reducing peak period demands, will avoid some amount of future costs for lower-voltage subtransmission and distribution capacity costs on the IOUs' systems. If this is true, then there is no reason why DG will not also avoid transmission capacity costs further upstream, on the CAISO's high-voltage transmission system. Yet the Public Tool modeling of the Energy Division, and of all of the parties opposing NEM, assume that DG will have no impact on CAISO-level transmission costs, and therefore assume zero marginal CAISO transmission costs. They do this despite the fact that the CAISO load-related transmission revenue requirement that is included in the Public Tool is clearly directly related to peak demand on the CAISO grid, as shown in Figure 9 of the VS-SEIA proposal, with a standard regression analysis calculating a marginal CAISO transmission cost of $87 per kW-year.[22]

Furthermore, the CAISO itself has made progress in acknowledging the potential of DG resources to mitigate transmission system overloads in its reliability planning studies. The

[2222] It is important to note that this CAISO transmission revenue requirement excludes transmission costs that are policy-driven, such as the transmission costs associated with accessing utility-scale renewable resources.

CAISO's most recent *2015-2016 Reliability Assessment* has identified dozens of transmission-level overloads throughout the system that could be mitigated with distributed resources, including energy storage, demand response, and DG.[23] In situations where multiple possible mitigation solutions are feasible, the preferred resources could serve as an alternative to expensive transformer replacement (as in the case of Vincent #1). In other cases (such as Lagubell in SCE Metro), preferred resources are the only identified mitigation solution in the CAISO studies. The potential for using non-wires alternatives, and specifically distributed preferred resources, as reliability solutions is clearly being recognized by the CAISO.

Perhaps other parties have excluded marginal CAISO transmission costs because CAISO-level costs are FERC jurisdictional and thus marginal CAISO transmission costs are not regularly calculated in CPUC ratemaking cases. However, this does not mean that these marginal costs are zero, and the Joint Solar Parties have calculated a reasonable value based on the costs that are included in the revenue requirements and rates that the Public Tool calculates. To ignore avoided CAISO transmission costs as a benefit of NEM, while including marginal CAISO transmission costs in rates as a cost of NEM, is inconsistent with findings in D.09-08-026 that T&D deferrals can and should be evaluated and is also factually inaccurate.[24] The following table shows the impacts of including marginal CAISO transmission costs as a benefit of net-metered DG. We note that properly including the avoided high-voltage transmission cost as part of the Value-Based Export Case makes that compensation rate higher than the $0.11 per kWh in the Modified NEM Credit case. This higher compensation rate for exports is what drives adoptions in the Value Based Export case higher than the Modified NEM Credit case.

23 Available at http://www.caiso.com/Documents/2015-2016PreliminaryReliabilityAssessmentStudyResults.zip

24 *See* Decision 09-08-026, p. 32 (rejecting utility arguments that T&D deferrals should not be included in cost-benefit methodologies for customer-sited DG) and Conclusion of Law No. 11 (It is reasonable to estimate the collective T&D deferral benefit of both grid-side and customer-side DG facilities based on DG penetration levels, without applying the restrictive physical assurance requirement, but using a methodology equivalent or analogous to the method employed by Itron in its SGIP Year 6 Impact Report.)

Table 8. Impact of Marginal CAISO Transmission Costs

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	576	8,128	0.84	0.54
Value Based Export	417	7,061	0.86	0.65
Modified NEM Credit	410	7,045	0.86	0.65
With Input Change				
Full NEM	574	8,107	1.09	0.74
Value Based Export	545	8,069	1.09	0.79
Modified NEM Credit	409	7,031	1.12	0.88

4. Consistent Use of Marginal Subtransmission and Distribution Costs

Electric rates in California are based on marginal costs, that is, on how the utility's costs vary with changes in demand for energy or capacity on its system. Such changes can result from a variety of sources – energy efficiency measures, installation of DG, or simply from variations in customers' usage – and a one kilowatt-hour (kWh) or kilowatt (kW) change in energy or capacity use from any of these sources should produce the same change in the utility's costs, as measured by its marginal costs. However, the marginal costs used in the Public Tool to calculate the benefits of DG when DG reduces the demand for energy or capacity are not always the same as the marginal costs used to develop the rates in the Public Tool. Under Full NEM, rates determine the lost utility revenues and bill credits that are the principal costs of NEM. The Public Tool uses consistent marginal costs for both benefits and costs for PG&E, but not for SCE or SDG&E. The Joint Solar Parties have corrected this inconsistency for SCE and SDG&E, and have used the same marginal costs both (1) to develop SCE's and SDG&E's rates in the Revenue Requirement section of the Public Tool and (2) to calculate avoided subtransmisison and distribution costs for these utilities in the Public Tool.[25] No such changes to the Public Tool were

[25] The change for SDG&E includes adding SDG&E's marginal substation costs as its marginal subtransmission costs. Marginal substation costs are a standard part of SDG&E's rates, but were omitted from the benefit (avoided cost) side of the Public Tool. SDG&E does not have what SCE and PG&E consider to be "subtransmission" circuits, but SDG&E does have substations that connect CAISO transmission facilities to its distribution system. These substations are a

necessary for PG&E. The following table shows the impact of this change on the Energy Division's results.

As requested in the June 23 ACR, the JSPS note that these changes to the SCE and SDG&E marginal subtransmission and distribution costs are "hard-wired" modifications made to the Public Tool. The Public Tool does allow a user to scale the IOUs' marginal subtransmission and distribution costs up or down,[26] but the same scaling factor applies to all three utilities. Thus, this input could not be used to make this correction only to the SCE and SDG&E marginal subtransmission and distribution costs, and this change had to be hard-wired in the Avoided Cost Calcs tab of the Public Tool. As requested, the following table presents the impact of this modification, showing how the results change between using the unmodified and modified versions of the Public Tool.

Table 9. Impact of Consistent Marginal Subtransmission & Distribution System Costs

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	574	8,107	1.09	0.74
Value Based Export	545	8,069	1.09	0.79
Modified NEM Credit	409	7,031	1.12	0.88
With Input Change				
Full NEM	574	8,096	1.15	0.78
Value Based Export	562	8,204	1.15	0.82
Modified NEM Credit	408	7,025	1.18	0.94

5. Locational Benefits

The Public Tool calculates the avoided energy costs from DG using a simplified model of the market-clearing price for energy at the trade hubs of the CAISO system. In the actual CAISO market, congestion costs and line losses cause energy prices to vary across the CAISO grid, with these locational differences captured in the CAISO's locational marginal prices (LMPs) at 3,000 nodes across the CAISO grid. LMP prices are higher in load centers, due to the congestion and

component of its T&D system that needs to be included on both the benefit and cost sides of the Public Tool's analysis.

26 Cells C18 and C19 in the "Key Driver Inputs" tab of the Public Tool.

losses incurred in moving power into these areas. Obviously, DG systems are associated with loads and are located disproportionately in the load centers where energy value is higher. As a result, the LMP price that DG avoids will be higher than the CAISO average market-clearing price at the trade hubs, which is what the Public Tool models. Accordingly, the Public Tool allows the user to adjust the avoided energy cost benefit of DG by a locational multiplier. The JSPSs used two different approaches to determining an appropriate locational multiplier. VS-SEIA looked at the difference over the last two years between the congestion costs in (1) CAISO trade hub prices (NP-15 and SP-15) and (2) the default load aggregation point (DLAP) prices for the three IOUs. This calculation resulted in a locational premium of 2% due to avoided congestion costs.[27] This value is conservative because it assumed a baseload production profile from DG. TASC and CALSEIA referenced a whitepaper from Kevala Analytics that used Geographic Information System (GIS) modeling from Kevala Analytics to associate each DG system on the CAISO grid to the nearest LMP pricing node. Kevala then matched the hourly profiles of DG generation to the hourly LMP prices at each node and calculated the resulting value of the energy from DG system. When compared to the average default energy values in the Public Tool, the results show that taking into account this location-specific value supports a locational multiplier of 4.8% on top of the average energy value.

Table 10. Impact of the Kevala Locational Benefits Adder

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	574	8,096	1.15	0.78
Value Based Export	562	8,204	1.15	0.82
Modified NEM Credit	408	7,025	1.18	0.94
With Input Change				
Full NEM	574	8,092	1.21	0.83
Value Based Export	572	8,456	1.21	0.85
Modified NEM Credit	408	7,023	1.23	0.98

27 *See* SEIA/ Vote Solar Proposal, p. 26.

6. Corrected Commercial Rates

The Public Tool is pre-loaded with non-residential rates that do not match the current or proposed rate schedules of the IOUs. For some utilities and customer classes they are very similar; for some of them they are far apart. E3 stated at the December 2, 2014 workshop that it was their intention to have some of the pre-loaded rates be greatly different from actual rate schedules to encourage users to make decisions on which non-residential rates to use. The JSPS believe that the pre-loaded rates were not intended to be the rates that are used by parties in their Public Tool runs.

Despite this, the Energy Division did not alter non-residential rates in either of their bookend cases. In their proposals, the Joint Solar Parties used current default rates from the schedules under which customers typically take service. In addition, the JSPSs used Option R rates, where available, for the DER rate rather than the standard default commercial schedule.[28] This latter change increased adoption. It is an overly generous assumption that all solar customers will use Option R, but the model only allows one schedule to be used by all DER customers in a customer class. Because applying both the current default rates for non-DER customers and Option R rates for DER customers results in slightly reduced adoption in two of the three policy scenarios, it is clear that using current default rates for non-DER customers decreases adoption while using Option R rates for DER customers increases adoption.

Table 11. Impact of Updated Commercial Rates

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	574	8,092	1.21	0.83
Value Based Export	572	8,456	1.21	0.85
Modified NEM Credit	408	7,023	1.23	0.98
With Input Change				
Full NEM	572	7,987	1.20	0.83
Value Based Export	571	8,147	1.20	0.83
Modified NEM Credit	462	7,440	1.19	0.94

28 SEIA / Vote Solar Proposal, p. 37 (Table 7).

7. DG/RPS Parity

The VS-SEIA Base Case contained modifications of Public Tool formulas to give distributed generation the same value in the NEM cost-benefit calculation equivalent to the value that RPS-eligible renewables obtain from the state's RPS program. CALSEIA included these modifications in sensitivity runs. The impact is similar to counting DER as a Bucket 1 resource, which TASC assumed in several of its sensitivity cases.

This adjustment in the JSPS's Public Tool modeling values DG "at parity" with new renewable generation from utility-scale projects developed under the RPS program, in terms of the energy, capacity, and certain environmental benefits that both types of renewable resources provide. The DG and RPS programs have long proceeded in parallel, and both result in the construction of new renewable generation. The studies of how California can reach its long-term GHG emission reduction goals make clear that the state needs both programs to reach the high penetration of renewables required to meet those goals. The fact is that, if there were no DG program, the state would need to replace the lost DG output on a one-for-one basis with more utility-scale renewable power through the RPS program, in order to maintain the same overall penetration of renewable generation on the California grid and to maintain progress toward the state's GHG goals. If there were no renewable DG, it is simply no longer reasonable to assume that the Commission would replace this renewable resource with new gas-fired power plants or the greater use of fossil fuels in existing plants. For example, the state's loading order clearly prioritizes "meeting new generation needs first with renewable and distributed generation resources" before fossil-fuel generation.[29] In contrast, the Public Tool continues the outdated assumption that DG mostly displaces short-term gas-fired generation, and only avoids reducing RPS generation by lowering utility sales, with the result that, in 2020, DG would avoid 67% gas-fired power and 33% renewables. The JSPSs submit that, if the DG program were to end today, the state would be extremely unlikely to replace two-thirds of the lost generation by building and using more gas-fired generation. We do not believe that this Commission or other state policy leaders would (or should) countenance such a step backwards, backsliding away from the progress that has been made toward California's long-term clean energy goals.

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[29] California Energy Commission, "Implementing California's Loading Order for Electricity Resources," Staff Report, CEC-400-2005-043 (July 2005), p. E-1.

Assuming "parity" treatment of DG and RPS is fully consistent with the changes to the RPS statute adopted in AB 327, in which the Legislature determined that the RPS goal should be a floor, not a cap, on the amount of new renewable generation. AB 327's adoption of the RPS target as a floor on the penetration of renewable generation thus codified the "no backsliding" principle that underlies the DG/RPS parity assumption which the JSPS have used in their modeling.

Although the JSPSs believe that the Public Tool's failure to value DG and RPS resources comparably does not reflect current state policy, we respect the Commission's request that parties show the impacts of the modifications that they make to the Public Tool, by running the Public Tool without the modifications. In addition, the changes to the Public Tool necessary to provide DG/RPS Parity are "hard-wired" modifications. As requested in the June 23 ACR, VS-SEIA provided a sensitivity case that does not assume DG/RPS parity (the No DG/RPS Parity case). In this sensitivity, we include the recognized and quantifiable societal benefits of reduced emissions of carbon and criteria pollutants from the gas-fired generation that DG avoids in this scenario. These are the same quantified benefits that the Environmental Protection Agency has used to justify the federal government's Clean Power Plan, and we ask the Commission to confirm its support for these benefits as well. We also model the lower market prices that result from reduced demand for market-priced, gas-fired generation. The results of this sensitivity are very similar to the results with DG/RPS parity. This demonstrates that it is reasonable to assume DG/RPS parity, as the quantifiable environmental benefits to California from increasing the penetration of renewable generation are worthwhile for the state as a whole, including for non-participating ratepayers.

The following Table 12 provides another example of the impact of the DG/RPS Parity modification, showing how the results in Table 11 change solely from adding the DG/RPS parity change.

Table 12. Impact of DG/RPS Parity

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
Without Input Change				
Full NEM	572	7,987	1.20	0.83
Value Based Export	571	8,147	1.20	0.83
Modified NEM Credit	462	7,440	1.19	0.94
With Input Change				
Full NEM	596	8,262	1.50	1.03
Value Based Export	706	9,195	1.49	0.95
Modified NEM Credit	432	7,196	1.53	1.21

The results in Tables 11 and 12 can be considered the end results of Public Tool analysis of the Joint Solar Parties. The results in Table 11 are very similar to the base case in CALSEIA's and TASC's successor tariff proposals.[30] The results in Table 12 are very similar to the base case in VS-SEIA's proposal and the GHG Credit Case in CALSEIA's proposal.[31]

IV. SUSTAINABLE GROWTH WILL NOT BE MAINTAINED UNDER OTHER PARTIES' PROPOSALS

A. Projected Adoption Rates Are the Key Metric for Assessing Whether Proposals Will Result in Continued Sustainable Growth in Customer-Sited Renewable DG

Parties that suggest adoption rates should not be included as an appropriate metric for sustainable growth[32] ignore the full text of the relevant statute. The Commission is under an obligation to adopt a NEM successor tariff that "ensures that customer-sited renewable distributed generation *continues* to grow sustainably." As the Commission Staff has recognized, when addressing this portion of the statute, the Commission must take into account *both* elements -- i.e., " continues to grow" and "sustainably."[33] The plain meaning of the term

30 CALSEIA Proposal, p. 8; TASC Proposal, p. 43, Table 3, and p. 44, Table 5.

31 SEIA / Vote Solar Proposal, p. 31 (Table 4); CALSEIA Proposal, p. 11.

32 *See, e.g.*, PG&E Proposal, pp. 36-37; SCE Proposal, p.11.

33 Staff Tariff Paper, p. 1-8

"continues" is "to maintain *without interruption* a condition, course, or action."[34] When the words of a statute are unambiguous, then the courts "presume the lawmakers meant what they said. The courts may not, under guise of statutory construction, rewrite the law or give the words an effect different from the plain and direct import of the terms used."[35] The Commission has followed this axiom of statutory construction while interpreting the provisions of the Public Utilities Code.[36] The use of the word "continues" demonstrates that the Legislature considers current installation rates of customer-sited DG to be sustainable.

The Joint Solar Parties maintain that "sustainably" is best interpreted from the perspective of solar market and industry stability. Adoption cannot grow if there is continual disruption. The IOUs have a view that "sustainably" means without subsidies. Beyond this dispute, however, the clear meaning of "continues" cannot be ignored. Accordingly, adoption rates are the best metric for determining whether the NEM successor tariff meets the statutory requirement of continued sustainable growth.

Attempts to discredit the use of adoption rates as a suitable metric for continued sustainable growth rely on the incorrect assumption that it is the sole criterion for determining the successor NEM tariff adopted by the Commission. PG&E asserts that the use of an adoption rate metric is inappropriate because "one might see more growth with a proposal that is inferior because the high growth is spurred by an unacceptably high impact on other customers."[37] Similarly, SCE argues that a NEM successor tariff that maintains the current rate of adoption is not sustainable because such would continue an inappropriate cost shift.[38] PG&E's argument overlooks the fact that the statutory requirement of continued sustainable growth is just one of several legislative requirements that the Commission must meet in adopting a successor NEM tariff, including that the successor tariff's total benefits to all customers and the electrical system must approximately equal its costs. Using adoption rates in this balanced fashion is consistent with the Staff's interpretation of "continues to grow sustainably" -- *i.e.*, "preserving and fostering

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34 http://www.merriam-webster.com/dictionary/continue

35 *City of Pasadena v. AT&T Communications of California, Inc.* (2002) 103 Cal.App.4th 981, 984; Code Civ. Proc. section 1858.

36 *See, e.g.,* Decision 10-06-019, pp. 2-3.

37 PG&E Proposal, p. 37.

38 SCE Proposal, p. 12.

sufficient market conditions to facilitate robust adoption of customer-sited renewable generation while minimizing potential costs to non-participants over time."[39]

SCE's argument regarding the impacts to non-participants from the use of adoption rates as a metric for sustainable growth misconstrues the Joint Solar Parties' position stated in our March 16, 2015 responses to policy questions. The Joint Solar Parties have made very clear that we are *not* recommending that the NEM successor tariff be designed to support continuing recent growth *rates* in perpetuity.[40] Rather, the adoption metrics that should be used to ensure the NEM successor tariff meets the statutory requirement are: A) that the successor tariff should not exacerbate the impact on adoption of the scheduled changes to the ITC in 2017; and B) that the most recent year's increase in installed megawatts over the previous year should continue in the years subsequent to the NEM successor being adopted. In other words, if the solar capacity installed in 2016 exceeds that installed in 2015 by 200 MW, the 200 MW year-over-year increase should be considered "sustainable growth" for future years. The Joint Solar Parties' proposals have illustrated that this adoption rate can be used as a metric for continued sustainable growth while also fulfilling the other statutory requirements.

B. Modeling Results Illustrate that Proposals Will Not Result in Sustainable Growth

1. Fixing Incorrect Inputs in Public Tool Runs of Other Parties

Applying the Public Tool inputs explained in Section III above to other parties' proposals demonstrates that adopting those proposals would have an excessively negative impact on the solar market, far more adverse than what is shown in those parties' Public Tool results. Generally, these results show that, under the other parties' proposals to substantially change NEM in California, solar adoption in California over the nine years from 2017-2025 would, at best, only equal the approximate 5 GW that soon will be installed under the current NEM program. This would not represent an industry that "continues to grow," the goal that the Legislature set in AB 327.

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39 Staff Tariff Paper, p. 1-4.

40 Joint Solar Parties Comment on Policy Issues Associated with the Development of Net Energy Metering Standard Contract or Tariff, R. 14-07-002 (March 16, 2015), p. 8.

Two assumptions are shared by all three IOUs and stand out as having large impacts on their adoption results: the low solar cost case and the 5% assumed rate escalation. A flaw in the system sizing feature of the adoption module of the Public Tool also has a major impact. These inaccurate assumptions significantly inflate the adoption numbers associated with the IOU proposals. Fixing these two assumptions and one flaw (the "Top Three Input Changes"), in addition to the other changes in the base cases of the Joint Solar Parties, yields the results shown in Table 13. This shows that for PG&E, SCE, SDG&E and ORA respectively, modeled 2017 adoption and cumulative adoption between 2017 and 2025 decline significantly when the JSPS input changes are made to the Public Tool.

Table 13. Public Tool Results with Corrected Inputs

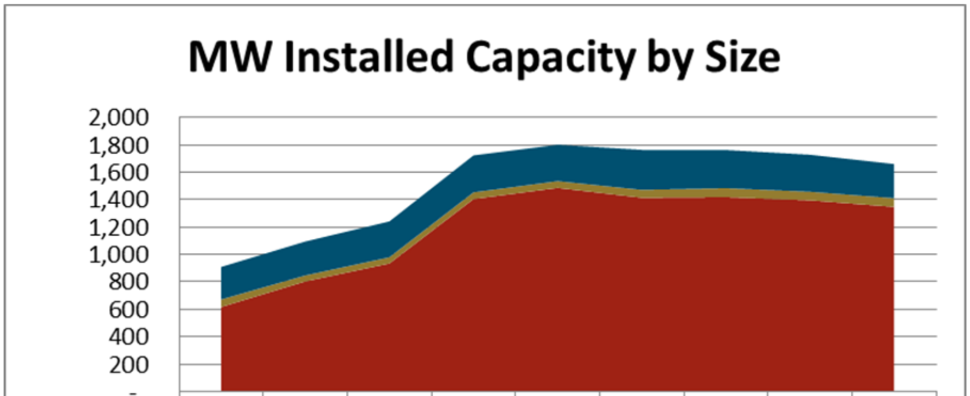
		PG&E	SCE	SDG&E Default	SDG&E SunCredit	ORA ICF$10
Proposing Party Inputs	2017 Adoption	909	582	481	359	1,247
	2017-2025 Adoption	13,679	9,545	5,756	10,946	15,255
Top Three Input Changes	2017 Adoption	320	118	127	3	278
	2017-2025 Adoption	8,738	6,811	3,954	1,503	5,817
All JSPS Input Changes	2017 Adoption	292	88	96	4	207
	2017-2025 Adoption	5,900	3,789	3,570	1,503	5,226

2. Extreme Results of System Sizing Flaw in the Public Tool

One of the biggest factors driving these unrealistic adoption numbers is an inherent bias within the tool itself that results in an unrealistic distribution of system sizes. Some parties' proposals, before correcting for this bias, are unrealistic in that they result almost exclusively in the adoption of large systems, such as the Energy Division High DG bookend discussed in Section III. As described above, the Joint Solar Parties believe that the mechanics of the adoption model do not do an adequate job of selecting a realistic distribution of system sizes. Two charts are shown here to illustrate this point, and other related charts are in Appendix A.

Looking first at PG&E preferred case, we see that, between 2017 and 2025, 79% of installed MWs come from systems where 100% of the customer's load is being offset. This is in contrast to less than 50% coming from large systems between 2008 and 2014.

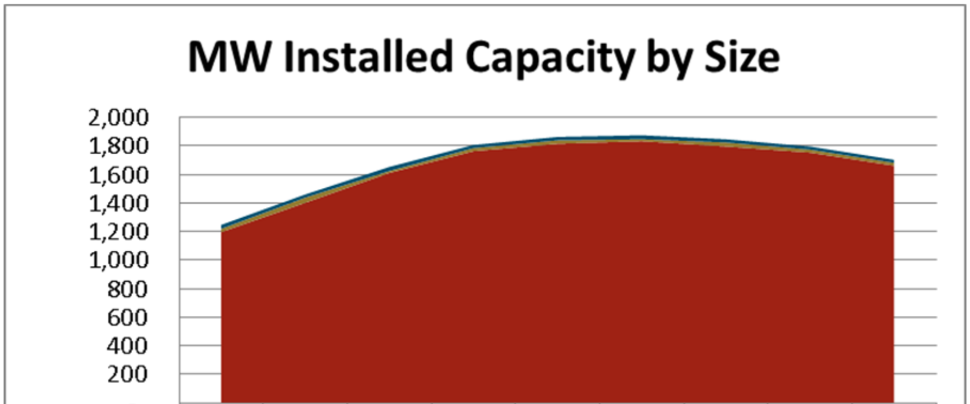
Figure 3. System Size Results of PG&E Additional 2-Tier Case



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	237	247	262	270	264	292	278	270	249
Medium	55	44	45	49	50	58	66	62	64
Large	616	803	934	1,404	1,485	1,414	1,418	1,395	1,347

Similarly, ORA's High DG Value 2-Tier case with a $10/kW Installed Capacity Fee (to which ORA recommends transitioning) is even more skewed, resulting in over 97% of the total MWs from large systems. Although it may be true that under ORA's proposal customers would need to offset as much generation as possible to overcome the negative effects of the installed capacity fee (ICF), it is simply not realistic to expect customers will be able to do that. Due to physical roof limitations and a conservative mentality among customers, it is unreasonable to assume that all customers would be willing and able to install systems that offset 100% of usage. The fact that the Public Tool allows for such a dramatically high percentage of large systems boosts the adoption number in the Public Tool for ORA's proposal, but the more likely result would be that many customers would not be willing or able to install systems large enough to overcome the ICF, and instead would not adopt at all.

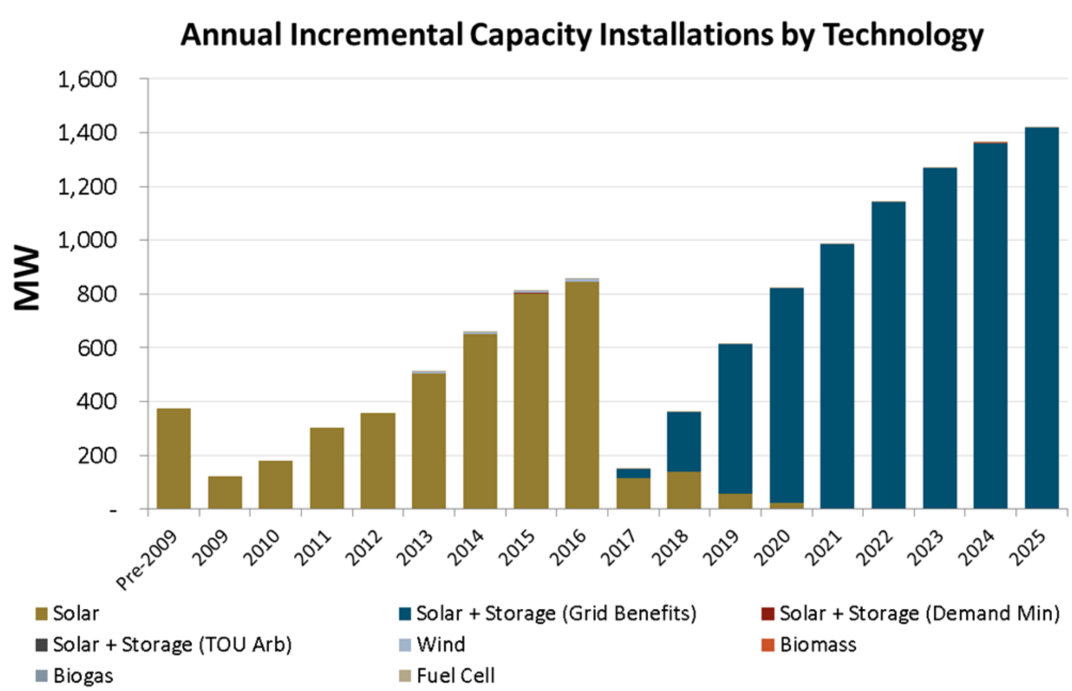
Figure 4. System Size Results of ORA $10 ICF Case



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	28	22	29	22	24	28	23	22	22
Medium	23	36	13	22	24	14	28	20	20
Large	1,197	1,402	1,612	1,764	1,816	1,834	1,797	1,754	1,662

TURN's proposal, with the DG Adder set where the results for PCT and RIM are within the range that TURN recommends, also results in almost exclusively large systems. In addition, this proposal results in PV+storage systems accounting for nearly all DER adoption after 2018.

Figure 5. DER Adoption Under TURN Proposal



The Joint Solar Parties have not yet pinpointed which of TURNs input assumptions lead to this result. Whatever the reason, the result is unrealistic and further demonstrates the limitations of the adoption logic in the Public Tool. Small input changes can lead to extreme swings in the results that would not be observed in reality. These limitations serve to exaggerate overall adoption levels and downplay the detrimental impacts that many of these proposed tariff designs would have on the market.

The JSPSs have addressed the extreme distributions of system sizes in the Public Tool with the system sizing fix described earlier. Further details on the distribution of adoptions under the unmodified party proposals, compared to party proposals with the JSPS base inputs, are provided in Appendix A.

3. Solar Would Not Be Possible for School Customers

Appendix C shows a pro forma solar proposal for a school district in the Central Valley. The analysis uses actual demand data for eight school sites that are strong candidates for solar and sizes solar installations to maximize customer savings. It considers three financing scenarios – a power purchase agreement (PPA), a certificate of participation (COP – i.e. a municipal bond), and low interest financing through Clean Renewable Energy Bonds (CREBs). In each of the scenarios, there are net benefits under the current net metering tariff in all years and net losses in the early years under PG&E's successor tariff proposal.

Under PG&E's proposal, the school system is in the red until Year 19 for the PPA, Year 21 for the COP, and Year 15 for the CREBs financing. This is a school system that would benefit greatly from stabilizing its energy costs, has a demand profile that is well suited for solar, and has enough structurally sound infrastructure to be able to install solar at a low price. This is the type of customer that should have the opportunity to install solar. Yet it would not be advisable for the school system to accept the questionable financial proposition of solar under PG&E's successor tariff proposal.

Table 14. Net Operating Benefits of Solar for Central Valley School System

	Financing	Year One Savings	Years 1-5 Savings
Current Tariff	PPA	$170,161	$893,148
	COP	$43,485	$370,082
	CEC	$118,358	$863,110
PG&E Successor Tariff	PPA	$(41,735)	$(215,423)
	COP	$(139,341)	$(618,663)
	CEC	$(81,761)	$(238,510)

4. Residential System Analysis Demonstrates that Implied Payback Is Far Different from Simple Payback

The Public Tool assumes that all DER installations are financed by PPAs, then creates an "implied payback period" that is meant to approximate the capital recovery period for a DER installation purchased with cash. However, this implied payback period is not equivalent to what is commonly understood as the payback period and produces results that are significantly shorter than a traditional payback analysis, potentially leading to incorrect conclusions. Although the JSPS have not corrected for this flaw in our adoption modeling, it reinforces our conclusions that the other parties' significantly overestimate future adoption and that the changes we have made to the Public Tool's adoption model are, if anything, conservative.

In the Public Tool's implied payback methodology, increased customer savings resulting from rate increases in the later years of a solar system's lifetime are accounted for in the early years because the total lifetime benefits are levelized. By moving the benefits forward, it loses touch with the meaning of a payback period and calculates payback periods that are too short. This impact is further magnified in the IOU, ORA, and ED bookend cases because the savings are assumed to grow by an unreasonably high 5% escalation rate.

Correcting for this extends the payback period by a year or more if the assumed rate escalation is 3% and by 2.4 - 3.4 years if the assumed rate escalation is 5%. These numbers are derived by developing a calculation that changes the "B/C Payback Conversion" factor, found in Cell H56 on the "Adoption Module" tab of the Public Tool, to be a growing annuity factor rather than a levelized annuity factor.[41] This converts the year one savings into a close approximation of the actual savings received in the first year. Starting with this more realistic first year savings, a simple payback calculation was developed to measure how many years of the increasing savings stream is needed to recover the NPV of the customer's solar system commitment.

Table 15. Extension of Implied Payback Period to Account for Increased Savings Over Time (Years)

Implied Payback in Model	Simple Payback		Additional Years	
	3% Assumed Rate Escalation	5% Assumed Rate Escalation	3% Assumed Rate Escalation	5% Assumed Rate Escalation
6	7.1	8.4	1.1	2.4
7	8.2	9.7	1.2	2.7
8	9.3	10.9	1.3	2.9
9	10.3	12.1	1.3	3.1
10	11.3	13.2	1.3	3.2
11	12.3	14.4	1.3	3.4
12	13.2	15.4	1.2	3.4

A second concern is that the Public Tool assumes all systems are third party financed, which can have reduced customer costs compared to cash purchase systems, particularly after a change in the ITC in 2017. While the ITC steps down from 30% to 10% for third party financed systems, the residential tax credit is scheduled for elimination. Also, third party financed systems can benefit from accelerated depreciation and pass those benefits through to customers along with the ITC. As a consequence, the NPV of customer costs is understated by not accounting for these factors because purchased systems constitute a substantial portion of the market.

A third concern is that the overall payback results, even when corrected for levelization and tax treatment, are still lower than many realistic potential projects. The binning of customers in the Public Tool has an inevitable averaging effect that does not accurately reflect the economics of a wide range of projects, and may also have other biases like overly optimistic

41 The B/C Payback factor is a levelized annuity factor that converts the NPV of benefits into a levelized stream of annual benefits. The implied payback then divides the NPV of system costs by that non-increasing stream of benefits to approximately arrive at a payback. The formula for a growing annuity is $((r-g)/(1-((1+g)/(1+r))^n)$, where r is the discount rate (9% for participant), g is the assumed utility rate escalation from the Key Driver Inputs C29, and n is the number of years of benefits, 25.

capacity factors. This can be clearly seen in the analysis of a cash purchase of a residential solar system detailed in Appendix B. This analysis used an hourly load profile for a typical customer in Fresno using data from the U.S. Department of Energy, sized a solar system to offset 66% of load, and obtained the solar system hourly production profile for a zip code in Fresno from the widely used PV Watts tool developed and maintained by the National Renewable Energy Laboratory (NREL). Having the hourly usage and hourly production, it is simple arithmetic to separate the production consumed instantaneously on-site and the production exported to the grid. The on-site consumption is matched to the rate schedule, and the exports are compensated at the rate in the successor tariff proposal. Comparing this to the cost of electricity that would be needed to satisfy the full electricity usage profile without solar produces a first year bill savings. The annual bill savings is increased at the assumed rate escalation level, subtracting the small amount of reduced production due to panel degradation. The results are capital recovery periods ranging from 13.0 years to 20.7 years, as shown in the second column of Table 16. The third column shows the implied payback period with benefits that increase over time. The fourth column shows the less accurate, shorter implied payback periods from methodology built into the Public Tool.[42] The simple payback numbers are larger than the Public Tool's implied payback numbers due to three factors – eliminating the effect of moving benefits forward, as shown in Table 15, purchased residential systems not using a 10% ITC or accelerated depreciation, and the use of averaged data for the bins and for system output assumptions that do not adequately capture the range of realistic customer cases.

Table 16. Payback Periods from IOU Proposals

		Implied Payback Period from Public Tool	
	Simple Payback Period from U.S. DOE Load Profile	With Increasing Savings Stream (Modified)	With Levelized Savings (Unmodified)
PG&E	13.0	11.0	9.7
SCE	13.3	11.6	10.3
SDG&E	20.7	10.5	9.0
ORA	13.4	11.5	10.2

In order to take the differences between IOU rates out of the picture, this analysis uses

[42] These are values for 2017 installations of residential solar.

PG&E rates,[43] which are higher than SCE's rates and lower then SDG&E's rates. If each IOU's own rates were used, SCE payback period would be longer and SDG&E's payback period would be shorter. Also, as demonstrated in Table A-7, SDG&E's successor tariff proposal would cause nearly all customers adopting solar to install small systems. A system that offsets a smaller portion of the customer's usage would have a shorter payback period under the SDG&E proposal than the system modeled in this typical customer example, which offsets 66% of usage. Hence, the simple payback periods in Table 16 are not the lowest possible simple payback periods under the IOU proposals, but they are an accurate characterization of the simple payback periods for one type of typical customer.

In its proposal, PG&E asserts that payback period is not a valuable metric for assessing sustainable growth because the use of PPAs and leases is widespread. Nothing could be further from the truth. Payback period remains a valuable metric that is well established within the research community as a measure of likely customer adoption. Moreover, PG&E's argument, even if true, fails to consider that at present customer finance options are swinging away from PPAs/leases and towards loans. PG&E appears to acknowledge this fact, stating that, "it is unlikely that all DG solar systems will be sold as leases between now and 2025, especially as technology costs continue to decline," but fails to grasp its significance.[44] The Joint Solar Parties agree with PG&E concerning the movement in customer financing of renewable DG as the matter has been widely discussed in various media sources.[45] The record developed in Rulemaking 12-06-013 also indicates that at present there is definitive swing away from the third-party ownership model back to the customer-owned model.[46] Thus the Joint Solar Parties see little merit to PG&E's claims that payback period is not a valuable metric to assess sustainability of the California solar industry. In addition, the analysis in the following section

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[43] The specific rates used are PG&E's rates after the restructuring ordered by D.15-07-001 is complete, as reported in "Supplemental Information of Pacific Gas and Electric Company Pursuant to July 23, 2015, Administrative Law Judge's Email Ruling," July 9, 2015: 18.432 c/kWh for usage up to baseline and 23.244 c/kWh for usage above baseline.

[44] PG&E Proposal, p. 46.

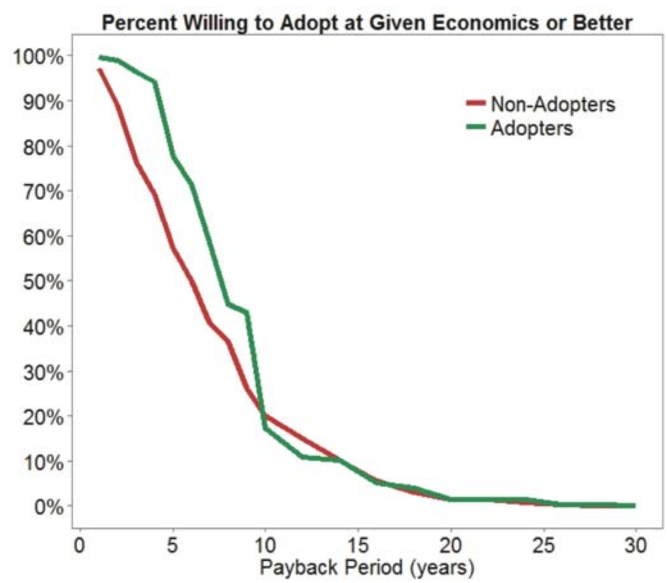
[45] *See, e.g.*, Why Solar Financing is Moving from Leases to Loans, by Herman K. Trabish, August 17, 2015, available at: http://www.utilitydive.com/news/why-solar-financing-is-moving-from-leases-to-loans/403678/.

[46] *See* Rulemaking 12-06-013, Transcript Vol. 24 (CALSEIA-Gerza), pp. 3941-3943.

demonstrates that the impacts of rate structure and generation compensation structure are directionally consistent for cash purchases and PPAs. What is bad for capital recovery is bad for PPA viability.

This analysis is also valuable as a "reality check" on the adoption module of the Public Tool as a whole. It uses a transparent and easily understandable methodology to produce a simple payback number that people understand. NREL has found that nine years is a critical threshold for payback period, with adoption dropping sharply beyond that point, as shown in Figure 6. This payback curve is used in the Public Tool and referenced at Cell D92 of the "Advanced DER Inputs" tab. Because the IOU successor tariff proposals result in payback periods far beyond nine years according to a transparent analysis, they clearly would have major negative impacts on the solar market and violate Section 2827.1(b)(1).

Figure 6. NREL Payback Curve[47]



5. PPAs Are Not Viable for Many Customers Under Other Parties' Proposals

The impacts described above for the sample Fresno customer derived outside the Public Tool are consistent with the bill savings impacts within the Public Tool. For example, for a residential customer in SCE's Climate Zone 9 (outskirts of Los Angeles), the average monthly

[47] Ben Sigrin, Easan Drury, National Renewable Energy Laboratory, Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics," (2014), p. 42.

savings in the first year of a 2017 installation project are shown below. The absolute monthly savings were based on an assumed first year PPA price derived from the Public Tool's pro-forma calculator under the base cost scenario and with the ITC dropping down to 10%. The "year 1" PPA price is approximately 25% below its levelized value to account for a common structure in which the PPA price annually increases by 2.9%. As shown below, the total customer savings become negative under the SCE and SDG&E proposals and are almost eliminated under the PG&E rate design. As expected with the reduced export compensation involved in these proposals, larger systems are disproportionately harmed.

Table 17. Monthly Savings from PPA Under Successor Tariff Proposals[48]

System Size	JSPS	SCE	PG&E	SDG&E
Large	28	(24)	4	(24)
Medium	28	(7)	9	(16)

The numbers above depend on future pricing assumptions. To eliminate that uncertainty, it is perhaps more informative to observe the difference in monthly savings from the various proposals, as shown in table 18.

Table 18. Difference in Monthly Savings Between JSPS Proposal and IOU Proposals

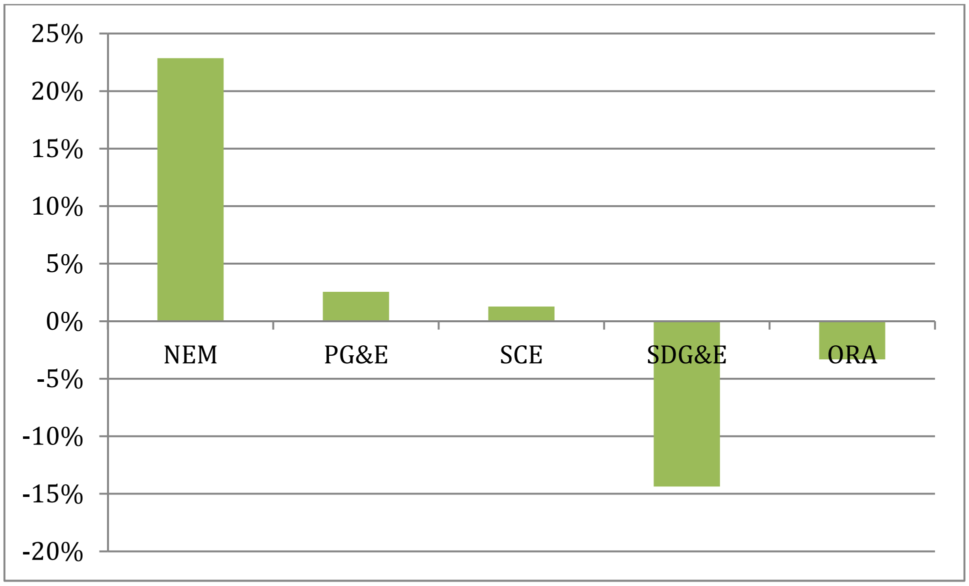
System Size	SCE	PG&E	SDG&E
Large	(52)	(24)	(52)
Medium	(35)	(19)	(44)

Similarly, a PPA would not be viable for the U.S. DOE load profile from the typical Fresno residential customer described in the previous section. The 4.6 kW-DC system required to offset 66% of the customer's usage would produce 6,680 kWh per year. At a first-year PPA price of $0.15/kWh, the customer would make payments of $1,002 in the first year. Comparing that to the reduction in utility payments shown in Appendix B demonstrates that the PPA would save the customer only 1% under the SCE proposal and 3% under the PG&E proposal. This is far smaller that the bill savings needed to motivate customers. The SDG&E and ORA proposals

48 This analysis uses Bin 391, a residential bin with 753,000 customers in Climate Zone 9 (Outer Los Angeles) with annual consumption of 8,900 kWh.

would cause the customer to lose money. Under all of these proposals, a PPA is not a viable option for this customer.

Figure 7. Bill Savings from PPA for U.S. DOE Typical Customer Load Profile



6. Year by Year Payback Results Demonstrate Upheaval in 2017

Although the implied payback calculation in the Public Tool produces results that are far shorter than true payback periods, the change in implied payback over time indicates that the financial prospects of solar for customers start worse and get better over time. Most parties reported the capital recovery period for customers as the "Average Implied Payback of DER Systems" averaged over a nine-year period of installations, which is the metric reported on the "Results" tab of the Public Tool. This masks the fact that it is not consistent over time.

A major shortcoming of the Public Tool is that solar cost does not respond to adoption. If adoption is reduced in a year, efficiencies will be lost and it will be more difficult for the solar industry to continue reducing costs. If the market suffers a major setback in the early years of the successor tariff, it will impair the ability to achieve projected adoption in later years.

For example, the Public Tool reports the Average Implied Payback for 2017-2025 installations for SCE's successor tariff proposal using JSPS inputs as 9.5 years. However, looking at the data year by year shows that it does not reach 9.5 years until 2022.

Table 19. Public Tool Implied Payback by Year for Residential Customer Under SCE Proposal

Installation Year	Average Implied Payback (Years)
2017	10.5
2018	10.6
2019	10.3
2020	10.0
2021	9.7
2022	9.4
2023	9.0
2024	8.7
2025	8.4

7. SCE Skews the Meaning of Previous CALSEIA Testimony

SCE misinterprets CALSEIA testimony from R.12-06-013 in an attempt to justify an excessively long payback period. SCE states that CALSEIA, "testified that 7.5-13.3 years is an appropriate implied payback range."[49] SCE then justifies its proposal because "it does meet the payback period range CALSEIA advanced."[50] This refers to a table in CALSEIA's testimony in R.12-06-013 listing the capital recovery periods for CALSEIA's proposed compromise rate structure. The capital recovery periods were 7.5-9.1 years for customers with demand greater than 500 kWh per month.[51] Although member companies expressed that a nine-year capital recovery period was too long to structure business around, it was a compromise position between the previous rate structure and the utilities' proposal.

CALSEIA measured that customers who use less than 500 kWh per month would have capital recovery periods of 11.5-13.3 years under the CALSEIA compromise rate structure. CALSEIA's conclusion from those numbers was that the solar market for low-usage customers would continue to be difficult, stating, "the capital recovery period is still too long for the

49 SCE Proposal, p. 21.

50 *Id.*, p. 22.

51 "Prepared Testimony of Adam Gerza on Behalf of the California Solar Energy Industries Association," R.12-06-013 (September 15, 2014), p. 16.

average customer," and therefore, "improved solar economics for low-usage customers that comes from flattening rate tiers does not greatly expand the potential solar market."[52]

SCE's interpretation of CALSEIA's testimony is in direct opposition to the true meaning of that testimony, and SCE's proposal for an excessively long payback period should therefore be rejected.

C. Lessons from Other Markets

Joint Solar Parties note that the industry now has some initial experience with NEM successor tariffs, with a few jurisdictions moving away from NEM and replacing it with different compensation regimes. These examples clearly demonstrate the significant disruption such changes can engender and the degree to which such changes, if embraced by the Commission, may fail to fulfill the statutory requirement to assure the continued, sustainable growth of rooftop solar. Below we provide examples that are close to home, both literally as well as in terms of the content of the reforms that were ultimately adopted. In both instances, the changes resulted in almost immediate and profound contraction of industry activity. These adverse outcomes will likely be exacerbated with the decline/elimination of the federal ITC at the end of 2016. While one could, and we anticipate the IOUs will, argue that things are different in California, the high degree of similarity between what has been implemented in the jurisdictions described below and what is being proposed in California by the IOUs and others, makes these examples instructive and indicative of what could easily happen in the IOU service territories should the Commission embrace radical departures from the current NEM regime.

1. Salt River Project (SRP)

Earlier this year, SRP established a new Standard Electric Price Plan under which all new customers deploying customer-sited solar systems are required to take service. Although officially adopted by the SRP board in February of this year, the new tariff applies retroactively to all solar customers that applied to deploy rooftop solar after December 8, 2014. Under this tariff, solar customers are subject to a range of fees that, but for the decision to deploy solar, would not otherwise apply, including significantly higher monthly distribution charges, as well as demand charges (where demand is measured based on the most intensive 30-minute peak

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52 *Id.,* p. 13.

period in the month). Additionally, as compared to the default residential tariff that the new rate plan replaces, solar customers receive significantly reduced bill credits for any energy sent back to the grid. Below is a table that provides an overview and comparison of the key elements of the E-23 default residential tariff compared to the new E-27 NEM tariff.

Table 20. SRP Default Residential Tariff

E-23 (Default Residential Tariff)			
Monthly Fixed Charge	$ 20.00		
Energy Charges			
	0-700 kWh	701-2000 kWh	Above 2000 kWh
Summer (May, June, Sep, Oct)	$ 0.110	$ 0.112	$ 0.123
Summer Peak (Jul-Aug)	$ 0.117	$ 0.118	$ 0.133
Winter (Nov-Apr)	$ 0.083	$ 0.083	$ 0.083

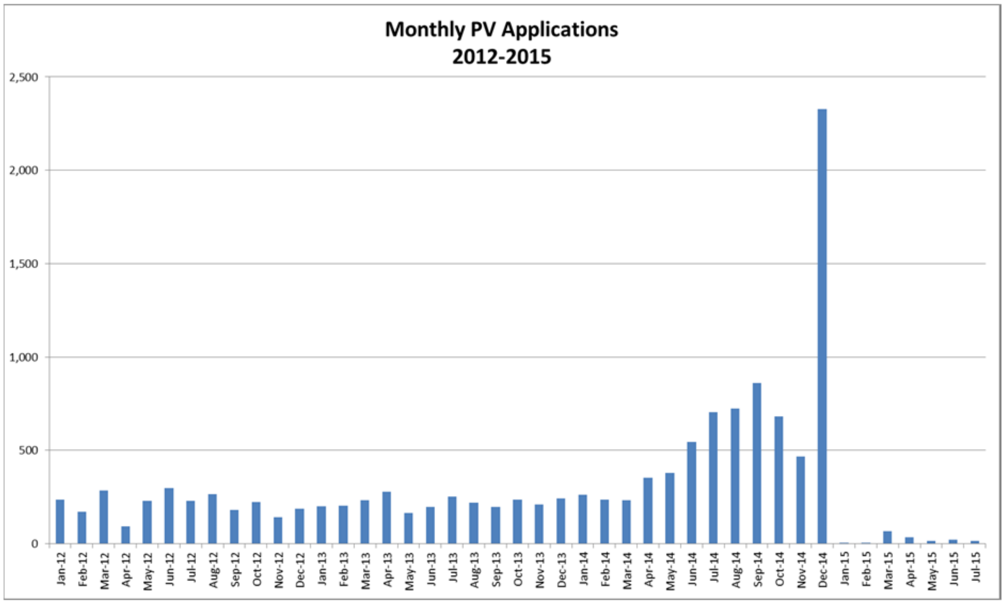
Table 21. New SRP Solar Tariff

E-27 (Solar-Specific Tariff)		
	< 200 amp	> 200 amp
Monthly Fixed Charge	$12.44	$ 32.44
Energy Charges		
	OnPeak	OffPeak
Summer (May, June, Sep, Oct)	0.049	0.037
Summer Peak (Jul-Aug)	0.063	0.042
Winter (Nov-Apr)	0.043	0.039
Demand Charges	0-3 kW	$ 2.87
	3-10kW	$ 4.57
	10+ kW	$ 7.91

The impact of the new rate structure on the solar market in SRP's service territory has been nothing short of disastrous in terms of solar adoption. Below is a table that provides an overview of monthly solar applications from 2012 through 2015.[53]

[53] Data from ArizonaGoesSolar.org. The information reflected in the table includes PV applications, both residential and commercial, however, because commercial applications only represent approximately 1% of the applications over the period shown in the table below, confining this analysis to residential PV would make minimal difference in the overall results and trends observed.

Figure 8. Solar Installations in SRP Territory



As can be seen, monthly applications declined abruptly post December 2014, indicative of the profoundly adverse impacts of the new rate plan on solar economics and customer uptake. A closer look at the data shows that over 99% of applications submitted in December 2014 were submitted on or before December 8, likely driven by the fact that applications submitted after this date would be subject to the new tariff. Of these, 57% were actually submitted on December 8 itself. Comparing the first seven months of 2015 to the same seven months in 2014 shows declines ranging from approximately 100% to, at best, a 70% decline in applications received each month. Collectively the number of applications received in the first seven months of 2015 represents a 94% decline relative to the same period in 2014.

2. Turlock Irrigation District (TID)

The recent experience in TID's service territory provides another example within California itself, providing a sense for the impacts on the solar industry when significant changes to the NEM framework are made. Unlike the IOUs, which are subject to Commission oversight and a robust stakeholder process, the Publicly Owned Utilities (POUs) in California are largely given free rein to pursue whatever NEM reforms they wish once they hit their respective 5%

NEM caps.[54] TID reached its NEM cap as of November 17, 2014.[55] Customers that have filed their rooftop solar interconnection application request since this date have been required to take service under a newly established Self-Generation Service rate. This new rate includes a number of significant modifications to NEM, including the state's first mandatory residential demand charge and a shift away from annual netting, which effectively allowed customers to roll-over excess credits from one month and apply them to usage in other months, to a monthly netting approach whereby any excess credits in a given month are sold to the utility at a rate well below retail. Additionally, solar customers are now also required to take service under a time-of-use rate, with a peak period that extends until 9 p.m., well after a solar system would have stopped generating energy and exposing these customers to high rates for a significant part of the day. Importantly, these requirements uniquely apply to solar customers in TID's service territory; there are no comparable rates mandated for non-solar customers.

As with the changes implemented by the Salt River Project, TID's changes have had an adverse impact on rooftop solar development in TID's service territory. Currently there is insufficient data on applications to exactly replicate the analysis presented above regarding SRP; however, looking at interconnections that have occurred to date under the new DG tariff suggests that the changes implemented by TID are having a very substantial and negative impact on the rate of solar deployment and adoption in its service territory. Below is a table that shows the number of systems interconnected.[56]

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54 Notably, the CA POUs also have a great deal of discretion in terms of how they calculate the 5% cap. In sharp contrast, pursuant to AB 327, the IOUs are subject to a specific methodological approach in how they calculate the 5% NEM cap.

55 *See* http://tid.com/solar-net-metering

56 Data provided by TID, reflecting interconnections through August 5, 2015.

Table 22. TID Solar Adoption

MW Interconnected TID

	Orig NEM	DG rate		Overall change from 2014 - installs under Original NEM
2013	200			
2014	527			
2015 through end July	190	87		
2015 End-Year estimate		*149*		*-72%*

Source: TID, data through August 5, 2015
End Year estimate taken by prorating monthly installation

Annualizing the interconnections that have occurred under the new DG rate in the first seven months of this year results in an estimated total for 2015 installs under the new tariff of approximately 149 systems. Comparing that to the installs that occurred in 2014 under the prior NEM rate (527 interconnections) suggests a decline of more than 70%. Notably, at least two of the nation's largest rooftop solar installers, SolarCity and Sunrun, have stopped offering solar to new customers in TID's service territory altogether, owing to the impacts of the new tariff on system economics as well as the inability to reasonably estimate customer first-year savings under the new rate structure with its demand charge.

3. Colorado

In contrast to SRP and TID, the Colorado Public Utilities Commission recently completed a comprehensive 18-month review of net metering in Colorado, and concluded that it should make no changes to net metering in Colorado at this time.[57] The Colorado Commission's review included four workshops before the full commission plus extensive written comments, covering the benefits and costs of NEM, the distribution system impacts of DG, and the experience in other states. In announcing this decision, the Chair of the Colorado Commission commented that Colorado's net metering program is currently working, that the Commission likes the "status quo," and that there is no immediate problem that needs to be resolved.

D. Changing NEM Would Impair Customer Decision Making

One of the most problematic aspects of the IOUs' proposals is that by adding three or more factors into the calculation of solar benefits (e.g., new demand charges, installed capacity

57 *See* http://www.dailycamera.com/boulder-business/ci_28706898/puc-ruling-no-changes-net-metering-colorado.

charges, monthly true-ups, interconnection upgrades, standby charges, Option 1/Option 2, etc.), the customer solar purchase decision is now “fraught” with much higher uncertainty than under the current NEM tariff. Richard Thaler and Cass Sunstein, researchers from Stanford and Harvard who authored *Nudge*, a 2008 Best Business Book of the Year finalist, define “fraught choices” as choices involving the following: costs now/benefits later; difficult versus easy; a choice rarely made versus a choice frequently made; and offering feedback slowly versus immediate feedback. It involves situations where our likes and dislikes are not well known. In a July 2014 study published in the International Journal of Business and Social Science, University of Notre Dame Professor George Howard notes:

> “Choosing to purchase a solar installation (instead of buying grid-produced electricity) lands on the more difficult end of all five of the “fraught choices”… deciding to purchase a solar installation [is] an extraordinarily difficult decision to make—even in instances where it is in the business’s (or homeowner’s) economic best interest to do so.”[58]

This research finding comes from the field of behavioral economics, which studies the effects of psychological, social, cognitive, and emotional factors on the economic decisions of individuals and institutions. Another important factor reinforcing the notion of the increasing difficulty of solar purchase decisions is “ambiguity tolerance-intolerance,” a construct that describes the relationship that individuals have with complex and ambiguous stimuli or events. Research findings show that most individuals across cultures view decisions with higher ambiguity as a threat. Adding intolerance for ambiguity to the characteristics of fraught choices multiplies the psychological barriers to considering the purchase of solar. Independent of the significantly reduced economic benefits to purchasers associated with the IOUs’ proposals, the complexity and ambiguity of these proposals would certainly discourage a very large number of prospective customers from considering a solar purchase decision.

Part of the increased complexity for customers would stem from new elements of variability that parties’ successor tariff proposals would introduce, making it more difficult to accurately estimate benefits of investments in solar energy. Solar companies working in good faith to provide accurate projections can use different assumptions, each of which are points

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[58] International Journal of Business and Social Science, Vol. 5, No. 8(1); July 11, 2014, *The Usefulness of Psychological Research in Creating a Better World*, George S. Howard, Department of Psychology, University of Notre Dame.

within a range of reasonable values. The greater the number of variables and range of assumptions, the wider the range of possible economic outcomes, which creates increased uncertainty and risk for the customer in assessing the financial benefits of their potential investment. or residential customers, this comes at a time when customers also need to develop an understanding of a greatly changed rate structure due to the changes ordered in D.15-07-001.

One example of a significant new variable is that the IOUs each use Retail Rate Credit + Value Based Exports as the compensation structure in their successor tariff proposals. This treats the electricity produced and consumed behind the meter differently from electricity exported to the grid, which forces a customer to make an estimate of what portion of produced electricity will be simultaneously consumed in each hour of the year in order to accurately model the financial benefits of their potential investment. Customers cannot look at their bills and have any intuitive sense of this effect. With NEM, it is simple for a customer to understand that they now pay for 800 kWh of electricity and after installing solar they will be paying for only 300 kWh, for example. If the solar purchase decision involves understanding imports versus exports versus consumption behind the meter, many customers would not trust their own ability to make sound judgments.

Future changes to load patterns are another area of uncertainty. Customers investing in solar or signing power purchase agreements are making commitments to offset their electricity usage far into the future. Many changes tend to happen in that time, which may include children growing up and moving away, families buying or retiring appliances or electronic devices, business activity increasing or decreasing, and much more. It is extremely difficult to predict future load, and most customers have some reluctance to commit to solar for that reason. If the solar value calculation gets more complicated by introducing different rates for exported energy, demand charges, and other features that are novel to residential ratepayers, this challenge will be greatly exacerbated.

Additionally, some elements of successor tariff proposals would change over time. TURN proposes to fix the compensation level for only ten years. SCE's proposal would apply changes to its Grid Access Charge to all customers, including customers with previous vintages of solar systems.[59] Solar providers would not have a good way to provide customers with reliable estimates of the impacts of these changes.

Another key concern and limitation of the Public Tool and its adoption model is that it assumes perfect information – that customers know all aspects of their consumption pattern currently and into the future. They need to know with a high degree of confidence how their energy usage coincides with the output profile of a solar energy system, how high their rate of usage peaks each month, and how these factors will change over time. In the Public Tool's calculation of the net present value of future bill savings, a solar system that offsets 100% of a customer's usage is precisely sized to produce the exact number of kWh that will be used by the customer. In reality, customers do not have this level of knowledge, and may be loath to make a decision to invest in a solar system or enter into a long-term contract if the value of that decision hinges on their ability to accurately predict complex characteristics of their future energy usage.

E. Demand Charges Would Disrupt the Industry and Undermine Adoption

By proposing the introduction of demand charges into the rate structure for NEM customers (as discussed more fully in Section VII below), certain parties to this proceeding would impose upon a growing segment of the residential and small commercial classes a charge which, for many good reasons that continue to be valid, has never been used in residential or small commercial rate design in California and is only rarely used by other utilities in the United States. Demand charges are complex and conceptually difficult for customers to understand,[60] and it is hard for consumers even to access data to know what their highest 15-minute demand might be.[61] While demand charges are manageable for large commercial, industrial, and institutional facilities that have substantial electricity demands (and bills), as well as facility managers dedicated to managing those demands and costs, they are not workable for small customers who spend only a few minutes a year focused on their utility bills. Imposition of such

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59 SCE Proposal, p. 34.

60 Demand, measured in kW, is the rate at which a customer uses energy as a function of time. In mathematical terms, it is the derivative of energy use with respect to time.

61 Residential appliances are rated according to their annual energy use (in kWh), for example by the DOE's Energy Star program. They are not rated according to the maximum demand, in kW, that they may reach when operating. In absence of such information, consumers would not be able to make informed decisions to respond to demand charges.

a rate structure on NEM customers will detract from the adoption of customer-sited renewable DG and will not contribute to the sustainable growth of customer-sited renewable DG, as envisioned by AB 327.

There is no doubt that there is significant potential for customer confusion in the implementation of residential or small commercial demand charges. A customer survey commissioned by the three IOUs in the context of the Commission's Residential Rate Design Rulemaking drove this point home. Specifically, the survey concluded that a demand charge "was confusing" to participants, who ended up making inaccurate comparisons to the monthly service fee because they failed to comprehend that a demand charge "varies based on kW demand levels."[62]

It is only since the advent of smart meters that data on demand for individual residential or small commercial customers has become available. To the knowledge of the Joint Solar Parties, no effort has been made to educate such customers about what their maximum demand is, how to determine it, or how to impact it through load management activities that are understandable and appropriate for small customers. Indeed, the Commission rejected as too complex and beyond the present scope of residential rate design the one proposal (from SDG&E) in the Residential Rate Design Rulemaking for an optional residential rate with a demand-differentiated fixed charge – a proposal that would not be as complex as a standard demand-based charge.[63] The Commission has consistently held that "considerable weight must be given to the ability of residential customers to both understand the principles behind the rates they are charged and accept those principles as reasonable."[64] Consumer acceptance and understanding is incorporated into the Commission's residential rate design principles.

There is no reason to think that residential customers considering installation of customer-sited renewable DG will be any less confused by the implementation of a demand charge than other residential customers. Indeed, these customers will be faced with trying to understand a demand charge in conjunction with the process of installing solar, which already is a complex transaction for most residential customers. In this regard, before imposing demand

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62 TASC Exhibit 102, Hiner and Partners, Inc. "RROIR" Customer Survey, April 16, 2013, p. 22.

63 See D. 15-07-001, at pp. 182-184 and Finding of Fact 160.

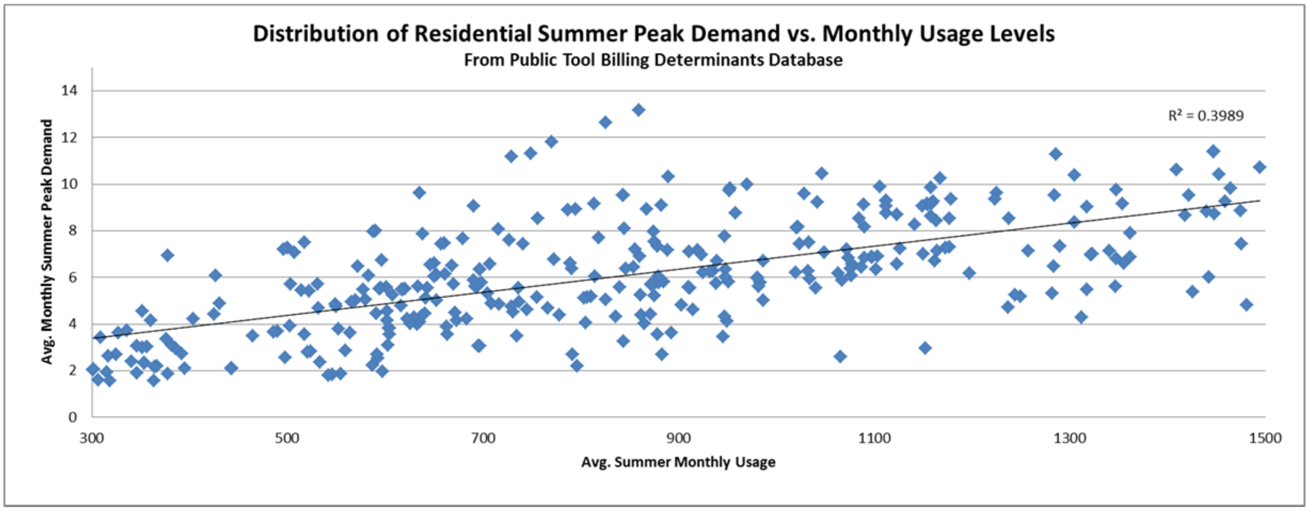
64 D. 88-07-023, at p. 5; also, D. 15-07-001, at pp. 214-217.

charges on these customers, it is critical to have some understanding of the extent to which a given customer's demand fluctuates from month to month, the predictability and seasonality of those demand fluctuations, as well as the extent to which solar can be reasonably anticipated to mitigate demand, if at all. Under the proposals that include demand charges, customers may find that their savings vary wildly depending on their demand profile. Savings volatility would adversely impact the ability of developers to reasonably predict savings and residential customers could be reluctant to put enough faith in those savings estimates to make a commitment of 20 years or more. One of the crucial benefits of NEM is that customers readily understand the concept of earning NEM credits simply by "running the meter backward" at the familiar, existing volumetric retail rate, and thus can calculate themselves the economics of the NEM transaction. Requiring customers to understand a much more complex rate design – and one that decreases their bill savings substantially – is certain to have a major adverse impact on the solar market. Faced with new tariff charges they do not understand, customers, more likely than not, will refrain from the installation of customer-sited renewable DG.[65]

To illustrate the significant uncertainty that demand charges would introduce, the JSPS pulled a subset of data from the billing determinants database of the Public Tool. Looking at all of the bins for typical residential customers with average summer monthly usage between 300 kWh and 1,500 kWh, we plotted the average monthly peak demand for each bin against its average monthly usage. The key takeaway from this chart is that for a given level of monthly usage (which is typically the only information available during the sales process), the level of peak demand can vary widely. For example, a given customer may have 900 kWh of monthly usage, but it will not be possible to know whether they are the type of customer with 2.5 kW peak demand or 10.5 kW peak demand. This wide variation makes it impossible to estimate the potential savings a customer could expect by installing solar, and inappropriately introduces significant complexity and risk. In addition, this increased variability will significantly increase customer acquisition costs, which will reduce adoption beyond the levels predicted in the Public Tool.

65 Technology is not likely to be of assistance to residential customers in managing demand charges. Technology to control residential and small commercial demand semi-autonomously – such as energy storage and building energy management systems – has been widely discussed, but is not yet widely available and will be a significant additional expense.

Figure 9. Variability of Peak Demand



F. Proposals that Undermine Financial Certainty of Customer-Sited DG Investments Will Undermine the Sustained Growth of the Customer-Sited DG Market in California

Savings certainty has been key to customers, the financial community, and third party solutions providers in supporting the market transformation that the CSI was designed to foster. To the degree the NEM successor tariff introduces substantial uncertainty and volatility into the level of savings that customers actually experience as a result of going solar, there will be important implications for solar financing.

For example, the California Solar Initiative Market Transformation Study discussed the impact that uncertainty can have for the continued access that solar providers need to financial markets, noting:

> While CSI has addressed and largely overcome the barriers foreseen by its planners, the current focus on NEM and rate reform has created heightened regulatory and policy uncertainty in the California market. Substantial changes in NEM and rate structures could change the value proposition of customer-side solar PV in California or increase investors' perceptions of risk in the market. Such changes could reverse progress toward several indicators of market transformation and sustainability.[66]

The Study also noted in discussing California's NEM reform efforts:

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[66] California Solar Initiative Market Transformation Study, Navigant Consulting, Inc., March 27, 2014, at pg. xiv.

> In terms of the market transformation framework and indicators discussed in this report, adverse changes in NEM and retail electricity rates could contribute to the following effects…A significant increase in the perceived regulatory risk in the California market might lessen banks' willingness to lend money or credit to solar PV installers looking to expand their business. Similarly, investors might be less willing (or charge more for their capital) to invest in TPO systems.[67]

This would also have significant implications on the availability of third-party financing for customers. The confidence that customers can place on bill savings under full retail NEM, coupled with third-party financing models (e.g. leases and PPAs) has played a critical role in expanding solar access. Because customers pay less for energy they receive from their third party-owned system than they would otherwise pay to their utility, coupled with the high value they place on energy services, they are unlikely to default on their payments. This is because doing so would result in them going back to utility service for the energy they were getting via their solar contract, resulting in higher energy costs. This understanding has allowed the credit rating threshold, as measured by the FICO score that customers must meet to qualify for third party financing, to decline. However, if customer savings are subject to high degrees of volatility owing to the inclusion of factors that are difficult to predict (such as demand charges, export credits that differ from the otherwise applicable retail rate, or regularly changing compensation rates for exported energy), the premise that customers are saving money may no longer hold, and the impact on future adoptions would be non-trivial. Defaults could increase and underwriting criteria, like FICO scores, could become more stringent.

Though not the only underwriting criteria used by companies offering leases and PPAs, FICO scores are a critical consideration. Given the distribution of U.S. consumer credit scores [68] were the investment community to require higher FICO scores to support third party financing, the share of the overall population that would be able to access solar, as enabled by the availability of the PPA and lease model, would be significantly impacted.

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67 *Id.*, p. 110.

68 *See* https://financere.nrel.gov/finance/content/tapping-underserved-solar-markets-can-we-extend-solar-deployment-customer-sectors-lower-or-n

G. Proposals Would Reduce Economic Spillover and Jobs Benefits Compared with the Joint Solar Parties' Proposals

A number of parties' proposals touch upon the economic benefits and jobs that will accrue from continued DER in their proposals: direct jobs from DER installers and servicers plus other spillover effects in the economy from the net benefits that DER creates. Both SCE and TURN reference Governor Brown's Clean Energy Jobs Plan, SCE in the context of ZNE Homes[69] and TURN in the context of a metric for balancing rate impacts and DG goals.[70] Sierra Club included a specific adder in its analysis to reflect local economic development benefits.[71] ORA asked the question most directly when it said, "In designing the successor tariff proposals, all parties are faced with answering the question-*What will be the economic effect of the successor tariff*?"[72] (emphasis original)

To determine the economic impacts of alternative successor tariff proposals, MRW retained an industry leader in macroeconomic analysis, Economic Development Research Group, Inc. (EDR Group) at the request of TASC, to quantitatively model the impacts on California employment and gross state product from potential changes in NEM policy. TASC provided EDR Group the necessary Public Tool outputs, such as participant bill savings, participant costs, avoided costs, and net bill impacts, for it to run its macroeconomic model: REMI (Regional Economic Models, Inc.). The REMI model, a dynamic computable general equilibrium (CGE) model, was designed for conducting "what-if" analyses for evaluating the gross economic and employment impacts of public policies such as NEM. The REMI model can handle a wide range of changes to the macro economy (by use of a relevant set of policy levers), and then re-solve the annual economy (through CGE adjustment imparted by its equation structure). It is superior to standard input-output models or models that simply correlate jobs to DER investment in that it considers the full economic ripple effect that increased economic activity in one sector creates in others. A description of REMI, how EDR Group conducted its analysis, and its detailed results are included in Appendix G.

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69 SCE Proposal, Attachment 1-2.

70 TURN Proposal, footnote 8 (p. 6).

71 CALSEIA Proposal, p. 14.

72 ORA Proposal, p. A-15.

EDR Group was provided with data for three cases: the TASC proposal, the ORA proposal, and the SCE proposal. These cases were framed relative to a base case of no additional NEM installations. So that an accurate comparison among the three cases could be made, the ORA and SCE proposals were modeled in the Public Tool with the same modifications that TASC used in its proposal. Scenarios were framed for 2017 through 2048, and for purposes of the study it was assumed the current NEM program will expire at the end of 2016 for new customers.

EDR Group concludes that the TASC proposal (where NEM is continued with minor changes) provides by far the largest positive macroeconomic impact of the three cases. The average annualized results of the macroeconomic analysis are shown below in Figure X below. The report further indicates that the TASC proposal would create an estimated 24,000 jobs by 2025. This is approximately 50% more jobs than would be created by the ORA proposal and over 75% more jobs than the SCE proposal.[73] The TASC proposal would also increase gross state product (GSP) by approximately $1.5 billion annually, or roughly $12 billion over the 2017-2025 period. This is over 40% more than the ORA proposal and more than 65% more than the SCE proposal.

Looking over the entire 2017-2049 period modeled, the results are even more dramatic, with the TASC proposal creating over 450,000 jobs (approximately 60% more than the ORA proposal and 85% more than the SCE proposal), and generating economic activity of $46 billion (54% more than the ORA proposal and 75% more than the SCE proposal).[74]

The annual job and GSP impacts result from significant multiplier effects, where job creation among California's other sectors is the result of the role of net savings to participants lowering the relative cost-of-doing business and making these sectors more competitive than they otherwise would have been, garnering more business and hence jobs. The residential segment is responsible for the largest share of job impacts because it achieves the largest share of net savings and has additional purchasing power, which supports more consumer spending. These macroeconomic effects are significant, far greater than previously estimated, and must be

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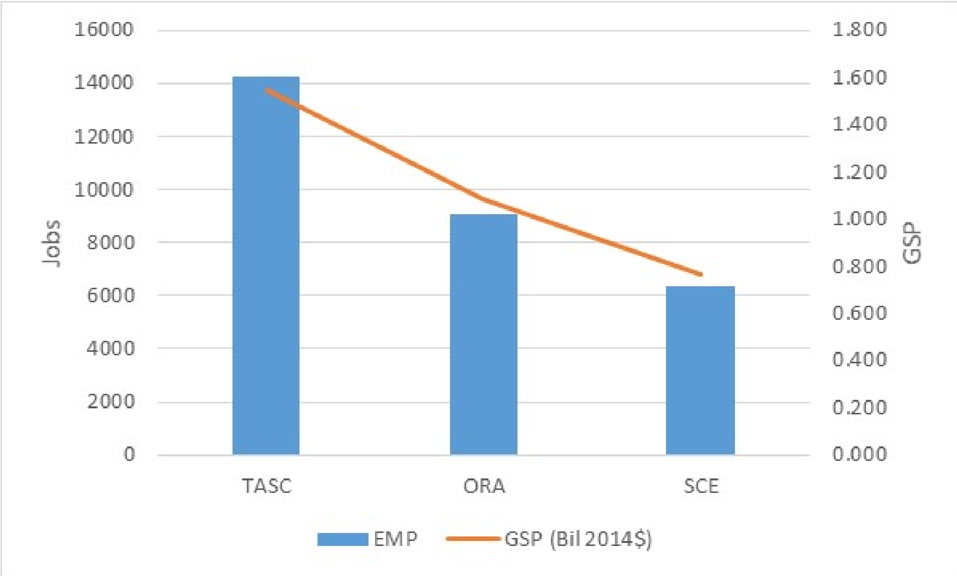
73 "Impacts on the California Economy Alternative Net Metering Policies"; Figures 3-2, 3-3, 3-4; pp.. 8-10

74 *Id.*, Table 2.4 pg. 6

taken into account when evaluating the proposals. As the figure shows, relative to the TASC proposal, the ORA and SCE proposals would result in the loss of jobs and decreased GSP. The contraction in jobs and economic activity under ORA and SCE's proposals are significant and must be considered as part of the evaluation of their proposals under Section 2827.1(b)(4).

Figure 10. Annual Average Impacts on Employment and Gross State Product of the TASC, ORA and SCE Proposals



V. BENEFITS WOULD NOT BE APPROXIMATELY EQUAL TO COSTS UNDER UTILITY PROPOSALS DUE TO UNDERCOMPENSATION FOR EXPORTS

A. Parties Err in Relying on RIM Test

As discussed previously in these comments and in prior comments by the Joint Solar Parties, the IOUs and other parties' unfounded definitions of "sustainable growth" result in over-reliance on the Ratepayer Impact Measure (RIM) Test, which is inconsistent with California policy and Section 2827.1(b).[75] For example, Section 2827.1(b)(3) requires the successor tariff be "based on the costs and benefits of the renewable electrical generation facility," which can

75 *See* TASC Proposal, pp. 24-29.

best be achieved with the Participant Cost Test (PCT).[76] This is because the PCT measures the costs and benefits of a DG technology to the customers who adopt it and compares customers' bill savings and tax benefits against their cost to install, operate and maintain the DG system. Additionally, 2827.1(b)(4) directs the Commission to balance total benefits and total costs "to all customers and the electrical system." The test that compares total benefits and costs to *all customers* is the Total Resource Cost (TRC) Test.[77] The Commission also emphasized the importance of the TRC Test in its last review of DG cost-effectiveness in D.09-08-026.

Additionally, it is important to note that if the Legislature had intended the NEM successor to result in complete non-participant indifference, AB 327 could have used language explicitly stating as much, as did SB 32 of 2009,[78] AB 920 of 2009,[79] SB 790 of 2011,[80] AB 2514 of 2012,[81] and SB 43 of 2013.[82] Instead, AB 327 calls for the Commission to ensure that total benefits "to all customers and the electrical system are approximately equal to total costs."[83] As the Joint Solar Parties have noted, this language points most directly to the TRC Test, which is the SPM analysis that directly compares the benefits and costs of a DG resource for <u>all</u> ratepayers.[84]

B. IOUs Ignore Avoided Cost Expectations in Their Distribution Resources Plan Filings

Assembly Bill 327 (Perea 2013), the same bill that directed the Commission to establish a NEM successor tariff, also directed the IOUs to file distribution resources plans (DRPs). In Rulemaking 14-08-013, the Commission issued a guidance document on February 6, 2015 that directed the utilities to include certain elements in their DRPs. The ruling stated:

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76 TASC Proposal at p. 17; *See* Joint Solar Parties March 16 Comments, pp. 13-14; *See also* IREC March 16 Comments, p. 9.

77 *California Standard Practice Manual*, p. 18.

78 Cal. Pub. Util. Code § 399.20(d)(3).

79 Cal. Pub. Util. Code § 2827(h)(4)(A).

80 Cal. Pub. Util. Code § 366.2(a)(4).

81 Cal. Pub. Util. Code § 2827.3(a).

82 Cal. Pub. Util. Code § 2833(p).

83 Cal. Pub. Util. Code § 2827.1(b)(4).

84 *See* TASC Proposal, p. 18; CALSEIA Proposal, pp. 14-15.

To implement this guidance, the Utilities shall include the following in their DRP filings:

a. An outline of all relevant existing tariffs that govern/incent DERs (e.g. NEM, EV-TOU, Rule 21).

b. Recommendations for how locational values could be integrated into the above existing tariffs for DERs.

c. Recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the above referenced demonstration programs.

d. Recommendations for further refinements to Interconnection policies that account for locational values.

The utilities' DRP proposals, filed on July 1, 2015, are laudable for including strategies to reduce distribution system expenditures by improving forecasting and planning to better incorporate the benefits of DERs. Nevertheless, those proposals failed to include recommendations for how those values could be integrated into existing tariffs, such as NEM. For example, SCE states: "To the extent locational values could be incorporated into existing tariffs, SCE believes such new tariff provisions should be developed in the tariff's existing, active Commission proceeding (as possible and appropriate) rather than in this DRP proceeding."[85] Despite this contention, in their NEM successor tariff proposals, the IOUs assign no distribution system value to net metered systems, directly contradicting the information presented in the DRPs.[86] PG&E and SCE give zero value to marginal avoided subtransmission and distribution system costs in their base case modeling, and SDG&E bases its proposal in part on the Energy Division low bookend scenario, which also gives zero value to these benefits. In assigning zero value to avoided subtransmission and distribution system costs in their successor tariff proposals, the utilities overlook the fact that the Commission has a separate proceeding in processes specifically intended to ensure that those values materialize. For example, SCE stated in its proposal: "SCE indicated 'No Value' rather than the 100% High or Low Case for Avoided

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[85] SCE, "Application of Southern California Edison Company for Approval of its Distribution Resources Plan" (SCE DRP) A.15-07-002, July 1, 2015.

[86] For example, 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. *See* SCE DRP, pp. 62-63; SDG&E, "Application of San Diego Gas & Electric Company for Approval of Distribution Resources Plan," A.15-07-003, July 1, 2015, pp. 43-44.

Distribution Costs Multiplier, as increasing customer-sited renewable DG has an associated net cost to the utility (not an avoided cost)." The statement assumes without basis in fact that that the DRPs will fail in their fundamental ambition of utilizing distributed resources to provide value on distribution circuits. In the end, the IOUs' decision to model a zero marginal avoided subtransmission cost is not supported by reality and produces results which undervalue customer-sited DG resources.

D. Significant Curtailment of RPS Resources Should Not Be an Expected Outcome in the Future

If the state is to meet its GHG reduction goals, stronger renewable energy policies will be needed for both utility-scale and distributed renewable energy. A 50% RPS will need to be part of this policy landscape. Under a 50% RPS, there could be significant curtailments of renewable output in certain months if options are not adopted to maintain the value of <u>all</u> renewables through the implementation of options that will take advantage of the supply of midday generation which results from renewable generation. Failure to account for such options in the Public Tool would have a major impact on the RIM results, because rates increase as a result of the higher per unit cost of RPS resources whose output is frequently curtailed. Among the actions already under development to address potential curtailment issues are: (1) expanding regional markets for clean generation from California; (2) developing new in-state markets that also contribute to the state's clean energy goals, such as increasing the charging of electric vehicles (EVs) during mid-day periods when renewable generation is abundant; and (3) utilizing energy storage to absorb over-generation to prevent significant curtailment. Each of these options can be modeled in the Public Tool, and the JSPS's 50% RPS scenarios do so as it is nonsensical for the state to forge ahead with a 50% RPS in order to meet the state's GHG reduction goals, only to see that renewable energy curtailed.

The potential for curtailment is a challenge that the state must resolve regardless of the relative penetration of RPS and DG resources. Fortunately, studies such as the work of Andrew Mills and Ryan Wiser at LBNL show that the state has many feasible options to maintain the value of renewables, both RPS and DG, as the penetration of these resources increases.[87] The

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87 LBNL, Andrew D. Mills and Ryan H. Wiser, *Strategies to mitigate declines in the economic value of wind and solar at high penetration in California* (Applied Energy 147 [2015]), pp. 269–

Public Tool, to the extent that it includes a significant amount of unmitigated curtailments, does not take into account mechanisms that can address potential curtailment. This is why, in earlier comments, parties requested that an option be included in the Public Tool to mitigate these curtailments in anticipation that such mechanisms will be in place in the future. The JSPS appreciate that E3 incorporated this functionality into the final version of the Public Tool, and the JSPS have used this assumption based on the following market developments that we expect to be in place to address this challenge.

1. Energy Imbalance Market (EIM)

The existence of the CAISO's Energy Imbalance Market provides great potential to integrate higher levels of renewable energy across the West without causing the reliability or over-generation problems that some have feared in the past. A recent FERC Staff Paper[88] 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." Similarly, the WECC Efficient Dispatch Toolkit[89] states that "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."

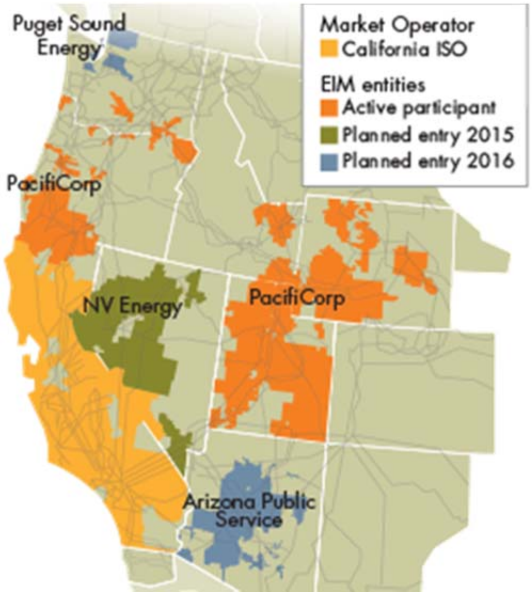
The EIM between CAISO and PacifiCorp is now a reality, with NV Energy planning to enter in 2015, and Arizona Public Service and Puget Sound Energy planning to enter in 2016. This vast area across the West represents significant diversity in both load and resources. With this diversity comes an opportunity to reduce reserve requirements, thereby freeing up flexible capacity to accommodate variable generators in an optimized way, and reducing the need to keep generators running at low and inefficient operating levels. This expanded regional market thus will reduce the costs of integrating a higher penetration of renewable resources.

278.

88 *Federal Energy Regulatory Commission Staff Paper: Qualitative Assessment of Potential Reliability* Benefits *from a Western Energy Imbalance Market (2013) - https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf.*

89 Western Electricity Coordinating Council, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," pp. 12-13 (October 11, 2011).

Figure 11. Energy Imbalance Market Participants



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 and reducing integration costs.

2. Electric Vehicle Load

The Public Tool does offer a limited ability to shift EV load to help reduce curtailments. However, a significant impact is only found in the model if one assumes a high penetration of EVs. Rather than creating an additional set of feedback effects by assuming high penetration of EVs, the JSPSs found it more appropriate to leave EVs at the base penetration level, while using the rationale that higher EV penetration will effectively reduce curtailments more dynamically than the Public Tool is able to capture.

3. Energy Storage Mandate

California plans to add 1,325 MW of flexible energy storage resources through the AB 2514 storage procurement framework. While the dispatch of these resources can be optimized for a variety of use cases, one of the primary use cases will be providing flexible capacity during times of system stress, including during potential over-generation conditions.

Each of the reasons discussed above provide solid support for assuming that the CAISO and the Commission will be successful in limiting the amount of economic curtailments of renewables as the state moves toward 50% RPS. Table 23 provides illustrative impacts on the high bookend case of the illustrative proposals provided in the Staff Tariff Report to illuminate the impact of utilizing the Public Tool's functionality for eliminating curtailment in a 50% RPS.

Table 23. Impact of Curtailment with 50% RPS on Energy Division High DG Value 2-Tier Case[90]

Illustrative Proposal	2017 Adoption (MW)	2017-2025 Adoption (MW)	TRC	All Gen RIM
50% RPS With Curtailment				
Full NEM	605	8,493	1.13	0.73
Value Based Export	587	8,160	1.13	0.80
Modified NEM Credit	442	7,307	1.15	0.89
50% RPS Without Curtailment				
Full NEM	624	8,702	1.17	0.74
Value Based Export	580	8,384	1.17	0.85
Modified NEM Credit	442	7,295	1.22	0.95

E. Correcting for Incorrect Assumptions in Other Parties' Modeling Results Demonstrates that NEM Participants Will Subsidize Non-Participants Under Other Parties' Proposals

The following incorrect assumptions used by other parties have the most dramatic negative impacts on the results of the *Standard Practice Manual* cost-benefit tests.

- **No marginal avoided transmission costs**. All model runs from proposals addressed in these comments assign no value to marginal avoided transmission cost with the exception of TURN's, which uses the low value of $12.50/kW-yr.
- **Inconsistent marginal subtransmission and distribution costs for SCE and SDG&E**. Unlike the assumptions for PG&E, other parties used lower marginal subtransmission and distribution costs for SCE and SDG&E to value the capacity savings from DG than the comparable marginal costs used to develop rates for these two utilities.

90 The JSP found similar impacts in relation to PG&E's successor tariff proposal. Results with the JSP Public Tool inputs plus 50% RPS were TRC of 1.20 and RIM of 0.96 with curtailment and TRC of 1.27 and RIM of 1.02 without curtailment.

- **Valuation of renewable DG resources** as avoiding mostly short-run gas-fired generation. Other parties model DG as a short-run resource that avoids, in 2020, 67% marginal gas-fired generation and 33% RPS resources. However, DG is a long-term renewable resource; if the state does not develop DG, it will need to develop an identical amount of RPS resources to meet the state's long-term greenhouse gas reduction goals. This requires valuing DG at parity with RPS resources or assuming Bucket 1 treatment of DG RECs in conjunction with a 50% RPS.
- **50% RPS with curtailment**. ll parties that assumed a 50% RPS in their model inputs also assumed that a significant portion of that RPS generation would be curtailed. As further described below, the JSP believe that: first, a number of initiatives currently underway are likely to reduce the amount of curtailment significantly below the level assumed in the Public Tool, and, second, the portion of the cost burden of curtailment that is not incurred by DG should not be attributable to DG.

Applying accurate Public Tool inputs to the successor tariff proposals of other parties demonstrates that the proposals severely undercompensate solar customers, and force them to subsidize other ratepayers. The following table presents the key metrics for the proposals of the IOUs and ORA, both as proposed by these parties and as modeled by the JSPS using the more reasonable set of Public Tool input assumptions. We discussed these assumptions above, and showed the individual impact of each one when applied to the ED Staff High Value DG 2-Tier case. Now we show the cumulative impact of all of these assumptions when applied to the IOU and ORA proposals. We show these cumulative impacts using the JSPS inputs both with and without the assumption of DG/RPS parity.

Table 24. Impacts of Correcting Public Tool Inputs for IOU and ORA Modeling

		PG&E	SCE	SDG&E Default	SDG&E SunCredit	ORA ICF$10
Proposing Party Inputs	TRC	0.68	0.75	1.18	1.20	1.11
	SCT	0.70	0.78	1.21	1.23	1.14
	Export RIM	0.50	0.75	1.36	0.84	0.43
	All Gen RIM	0.40	0.49	0.66	0.90	0.60
JSPS Inputs Without DG/RPS Parity	TRC	1.24	1.29	1.25	1.39	1.24
	SCT	2.15	2.25	2.16	2.43	2.15
	Export RIM	1.65	2.39	2.98	1.43	0.79
	All Gen RIM	1.03	1.17	1.10	1.55	0.97
JSPS Inputs With DG/RPS Parity	TRC	1.49	1.52	1.51	1.70	1.55
	SCT	1.80	1.85	1.82	2.49	1.87
	Export RIM	2.06	2.88	3.53	1.80	1.01
	All Gen RIM	1.24	1.40	1.31	1.94	1.26

Using the JSPS's reasonable assumptions in the Public Tool, with or without DG/RPS Parity, the RIM results from the proposals of other parties are, in almost all cases, generally much higher than 1.0, which indicates an unwarranted cost shift from solar customers to non-participating ratepayers. For example, a RIM score of 1.25 indicates that the bill savings for DG customers is 20% less than the benefits that those customers provide to the grid, essentially, funding a subsidy for other ratepayers. Proposals with RIM results significantly higher than 1.0 should be rejected. California's clean energy goals will be delayed and complicated if the NEM successor tariff requires solar customers to subsidize other ratepayers in addition to bearing the full cost of their DG systems. We note that the export RIM scores are particularly high for proposals, such as those from PG&E, SCE, and the "default" SDG&E proposal, which feature distinct rates for NEM exports that are much lower than the retail rate, and much lower than a reasonable measure of the long-term benefits of such exports. Given these results, there is no need to saddle NEM customers with additional fees, be they new demand charges, new fixed charges, or the standby and non-bypassable charges that SCE proposes to apply to non-residential NEM customers.

Finally, although the TRC scores are lower without the assumption of DG/RPS parity, the SCT scores are much higher. This is because, if one does not assume that renewable DG avoids 100% RPS generation, DG will avoid two-thirds gas-fired generation, and the higher societal benefits of this displacement are included in the modeling using the JSPS's assumed societal benefits. These additional carbon reduction and health benefits are the same ones that the EPA has used to support the federal government's Clean Power Plan. These high societal benefits show that it is cost-effective for California to continue to increase the penetration of renewable resources and that, if there were no DG, the state would replace DG with additional RPS generation on a one-for-one basis.

VI. DISCRIMINATORY FEES AND RATES PROPOSED BY VARIOUS PARTIES ARE ILLEGAL UNDER CALIFORNIA AND FEDERAL LAW

The IOUs are consistent in their efforts to force NEM residential customers onto a specific tariff and then to layer on discriminatory charges in contravention of state and federal law. The IOUs, as well as ORA and NRDC, are advancing the assessment of significant new charges on NEM customers alone, to the exclusion of other residential customers, in the absence of a substantial showing, indeed any showing, that the costs to serve such customers are different than the costs to serve other residential customers. Without such a showing by the parties advancing these proposals for new charges, the Commission cannot find the charges to be just and reasonable under the applicable provisions of state law and Federal Law.

A. State and Federal Law Require that a Separate Rate Structure for NEM Customers Be Based on a Substantial Showing that the Cost to Serve Such Customers Is Different

State law requires that rates be non-discriminatory.[91] Public utilities are prohibited from establishing any "unreasonable" differences as to rates and charges between classes of service. Therefore, consistent with state law, parties advancing disparate rate structures for NEM customers bear the burden of proving that proposed rates and classification are just, reasonable and nondiscriminatory. Section 2827.1(b)(7), added by AB 327 to delineate the NEM successor tariff, reiterates that "[t]he commission shall ensure customer generators are provided electric service at rates that are just and reasonable." Specifically, any proposed rate classification for NEM customers must overcome a significant burden of demonstrating that the cost of serving

91 *See, e.g.* Cal Constitution Article XII, Section 4; Public Utilities Code section 453(c) (c) (" No public utility shall establish or maintain any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.").

customers that self-supply electricity with on-site solar generation varies significantly from the cost of serving customers with similar load characteristics that do not have solar, such that a different rate classification is justified.

As the Utah Public Service Commission (Utah Commission) recently recognized in rejecting calls for discriminatory fees merely because NEM customers decrease their purchases from their respective utilities:

> Simply using less energy than average, but about the same amount as the most typical of PacifiCorp's residential customers, is not sufficient justification for imposing a charge, as there will always be customers who are below and above average in any class. Such is the nature of an average. . . . [I]f we are to implement a facilities charge or a new rate design, we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers.[92]

The Utah Commission also recently found that NEM Customers are not "distinguishable on a cost of service basis from the general body of residential customers."[93] Parties advocating for discriminatory treatment of NEM participants have offered no evidence that NEM participants are distinguishable from the general body of utility customers or even low-usage customers.

Similarly, federal law also requires that any separate rate structure for NEM customers must be based on a substantial showing that the costs to serve such customers are different. PURPA requires utilities to interconnect "small power production facilities" that meet Federal Energy Regulatory Commission (FERC) eligibility requirements for qualifying facilities (QFs).[94] QF status automatically applies to on-site solar generators up to 1 MW,[95] and includes QF

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[92] *Id.*, pp. 67-68.

[93] Public Service Commission of Utah, *PacifiCorp dba Rocky Mountain Power 2014 General Rate Case*, Docket No. 13-035-184, Decision and Order (Aug. 29, 2014), p. 67.

[94] 18 CFR § 292.303(c).

[95] 18 CFR § 292.203(d) (exempting facilities with net power production capacity up to 1 MW from certification requirement).

generators that participate in NEM.[96] The FERC's regulations implementing PURPA requires that rates for electricity sales to QFs "[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[97] Differential rates for QFs are only considered to be non-discriminatory when they are "based on accurate data and consistent system-wide costing principles"[98] and only "to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[99]

In support of SDG&E's proposal to saddle customer-generators utilizing renewable DG with demand charges, SDG&E produced a table showing rate designs that other utilities around the country have proposed or implemented in response to the growth of customer-sited renewable DG in their service territories. SDG&E's simplistic analysis in no way provides any useful information in assessing whether a demand charge as proposed by SDG&E is legal under California and federal law. Moreover, the table contains factual inaccuracies that undermine what limited use it may have in assessing reasonable approaches to rate design for customer-sited renewable DG. For example, SDG&E mentions Dominion Virginia Power's implementation of a distribution standby charge, but fails to mention that the imposition of such a demand charge was specifically allowed under state law and the charge only applies to residential systems above 10 kW-AC and certain agricultural customers. The charge imposed by Dominion is also not a capacity-based charge as stated in SDG&E's table, but rather the charge is a true demand charge that is reduced by the amount of distribution charges the customer paid in kWh rates. Furthermore, Georgia Power does not offer NEM so the characterization of any charges for Georgia Power as a NEM Option is inaccurate. The $4.50/month charge listed by SDG&E is a metering charge. The $0.82/month charge imposed by Alabama Power noted in SDG&E's table was adopted without any discussion or analysis by the Alabama Public Service Commission so its inclusion provides little support for the idea that the move to impose charges on customer-sited renewable DG was based on necessary costing principles. One can hardly hold up Georgia Power, Alabama Power, or Dominion Virginia Power as leaders in customer-sited renewable

96 Sun Edison LLC, 129 FERC ¶ 61,146 (2009) (recognizing onsite generators that participate in NEM as eligible for QF status even if they make no net sale of electricity to a utility).

97 18 CFR Sec. 292.305(a)(1)(ii).

98 18 CFR Sec. 292.305(a)(2).

99 *Id.*

DG. Each has minimal amounts of net-metered DG on their systems. As noted above, Georgia Power does not even offer NEM. Alabama Power has 513 kW of NEM systems in their service territory while Dominion has 9.03 MW (a paltry 0.055% of their peak load). Salt River Project's current NEM tariff is under appeal on antitrust grounds and HECO's proposal has not been adopted by the Hawaii Public Utilities Commission. Thus, in sum, SDG&E's table simply provides no support for the idea that unbundling of rates is the correct mechanism to support continued, sustained growth in customer-sited renewable DG as required under Public Utilities Code Sec. 2827.1(b)(1).

As illustrated below, the burden imposed by state and federal law on parties proposing disparate rate treatment for NEM customers has not been met, and accordingly the rate classification for NEM customers that has been advanced by some parties to this proceeding must be rejected.

B. Parties Advocating Disparate Rate Treatment for NEM Customers Have Not Made the Necessary Showing

PG&E,[100] SDG&E[101] and NRDC[102] propose that the Commission adopt new residential rate schedules for NEM service that include a new demand charge. SCE[103] and ORA[104] propose that NEM customers be subjected to a fixed charge based on the installed nameplate capacity of their NEM systems. Neither demand nor fixed charges are part of the current residential rate structure, and therefore are not "consistent with system-wide costing principles." These parties are proposing a fundamental shift in how a growing segment of residential customers would be

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100 PG&E proposes that the Commission adopt new schedules for NEM service for residential and small commercial customers that include a small maximum demand charge of $3 per kilowatt (kW)-month to recover a portion of the costs related to the distribution system used to serve these customers. *See* PG&E Proposal, p. 13.

101 SDG&E proposes a Grid Use Charge ($/NCD-kW) to recover that portion of the distribution costs related to a customer's demand or impact on the grid. *See* SDG&E Proposal, p. A-41.

102 NRDC proposes a demand charge that would be assessed by taking the average of the two highest 15-minute capacity periods over the course of each monthly billing period. *See* NRDC Proposal, p. 6.

103 SCE proposes a $3.00 kwh month Grid Access Charge based on installed nameplate capacity of the system. *See* SCE Proposal, p. 26.

104 ORA proposes an Installed Capacity Fee based on capacity of generation system. *See* ORA Proposal, p. A-12.

charged for electricity consumption. Similarly, TURN's proposal rests upon a framework that has never been adopted in California and violates customers' right to consume energy generated on their premises with their private property. These parties all propose to single out NEM customers from other residential customers (even other low-use customers with similar load patterns) and to charge them on the basis of a theorized DG customer responsibility for some greater portion of the utility's total cost of service rather than on the basis of how all residential customers, in the aggregate, contribute to utility costs, as is the current practice. Such a departure from the Commission's historic rate design and costing principles is discriminatory, and thus illegal under California and federal law, and, therefore, must be rejected by the Commission.

The purported rationale behind the assessment of such charges on NEM customers is to ensure such customers pay "an appropriate share of the infrastructure costs required to serve them."[105] These parties assert that if distribution costs are collected only in volumetric energy (per kWh) rates, as they currently are for all residential customers, then a NEM customer that offsets most of its load pays very little for the distribution infrastructure necessary to serve them.[106] Similarly, they argue that "DG customers impose costs at similar levels as they did prior to installing the DG system, but no longer make the same contribution to pay for those costs."[107] TURN predicates its proposal similarly, stating, "A customer with onsite generation could offset most or all utility charges (except for the minimum bill) even though they continue to require electric service at night, during early evening distribution circuit peaks, and on an as-needed basis over the electric distribution network."[108] These are the same arguments made in advancing fixed charges and flat rate proposals in the RROIR proceeding that the Commission did not find persuasive.[109]

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105 PG&E proposal, p. 14 ("PG&E's proposal to establish demand charges for future NEM service is necessary to ensure these customers pay an appropriate share of the infrastructure costs required to serve them regardless of their net usage."). *See also* SDG&E Proposal, p. A-4 ("SDG&E's proposal eliminates hidden indirect subsidies and requires NEM customers to pay their fair share of infrastructure costs.").

106 PG&E Proposal, p. 14.

107 SCE Proposal, p.26.

108 TURN Proposal, p. 11.

109 *See* Decision 15-07-011.

These parties attempt to illustrate their point by pointing to purported cost shifts from NEM customers to non-participants under the current NEM rate structure. In other words, NEM customers allegedly are not paying the cost of the infrastructure to serve them, so these costs are being shifted to other customers. They base these statements on analysis that takes a parsimonious view of the benefits DG provides and an incorrect view that an individual customer has a unique responsibility compared to ratepayers overall. In reality, concerns about NEM customers are no different from concerns about any low-usage customers.

Furthermore, assertions that NEM customers do not contribute to the cost of infrastructure necessary to serve them are simply inaccurate. As conclusively demonstrated through the August 3 submissions of the Joint Solar Parties, NEM participants continue to contribute towards their cost of service in a meaningful manner when they are compared to other participants in other demand-side management programs that do not have RIM Test scores at or close to 1.0. Moreover, when methodologies (the TRC and SCT) commonly used to assess the benefits of demand-side resources like energy efficiency are applied to NEM, the benefits of NEM clearly outweigh the costs.

1. NEM Customers Pay for Infrastructure Costs When They Take Services from the IOUs

The fact that a NEM customer may export power to the grid, earning credits that can result in a relatively low net bill from the IOU, does not mean that such a customer is not paying for their use of the grid when they use it. As currently structured, and as the Joint Solar Parties advocate should continue, NEM customers are charged the full retail rate (including the cost of transmission and distribution infrastructure) for the power they draw from the IOU system.

2. Proposed Charges Are Not Based on Cost to Serve

A demand charge structure such as the one proposed by PG&E, SDG&E and NRDC could result in overcharging NEM customers for their use of the distribution system. Demand charges are based on a customer’s maximum 15-minute usage during a month. Demand charges will often result in a mismatch between the days and hours when individual solar customers experience their individual maximum 60- or 15-minute usage and the days and hours when system or circuit peak demands actually occur. This is true because the maximum demands of solar customers will often occur on overcast days when solar PV output is low.[110] Because overcast days are generally cooler, they will seldom be among the highest system peak demand days (which usually are hot, sunny days) that drive the IOUs' system capacity costs. Similarly, cloud cover that reduces local solar output also generally reduces local demand, and therefore circuit capacity costs are not driven by demand at these times. The result is that, if a solar customer is charged a demand charge based on his highest 60- or 15-minute usage in the month, the solar customer will overpay for capacity-related costs, a fact recently recognized by the Commission when it adopted an "Option R" rate schedule with reduced demand charges for solar customers:

> SEIA's thorough analysis convincingly demonstrates the inaccuracy of maximum TOU demand charges. The inaccuracy is due both to the fact that customers' individual maximum peak period demands may not coincide with system peaks and to the failure of demand charges to appropriately recognize the benefits of load diversity.[111]

In addition, maximum demand charges that apply 24 hours per day, such as the one proposed by PG&E, would only compound the problem. Specifically, PG&E proposes a maximum demand charge to recover distribution costs that is based on a customer's peak 60-minute demand (for residential) or 15-minute demand (for small commercial), regardless of when those demands occur. PG&E justifies the use of this "any time" maximum demand charge on the grounds that it will recover distribution costs that are not related to the system peak demand. Such a proposal ignores the fact that, even if the portions of the distribution system covered by these costs do not peak at the same time as the system as a whole, they do exhibit peaks at specific other hours. For example, many portions of a utility's distribution system serving residential customers peak in the late afternoon and evenings during the summer. Distribution circuits serving small commercial loads often peak in the early-to-mid-afternoon when solar output is particularly high. The resulting diurnal profile of distribution circuit peaks for SDG&E is shown in the Figure 12 below. Figure 13 shows the distribution of PG&E's weekday peak capacity allocation factors (PCAFs), which are used in the Public Tool to allocate

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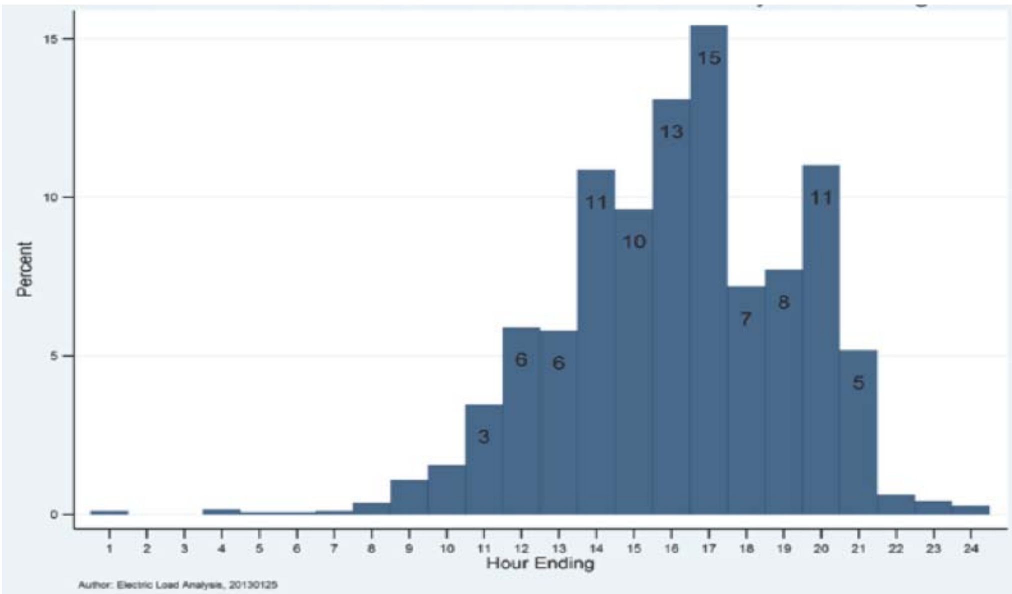
110 Summer data from California shows that days with low solar output tend to be cooler, overcast days with a persistent marine layer along the coast, and days with high solar output are hot and sunny days with few clouds and high electric demand.

111 Decision 14-12-080, p. 18.

subtransmission and distribution costs to TOU periods. E3 derived these PCAFs from "substation load shapes provided by the IOUs, aggregated to climate zones."[112] Thus, it is not cost-based to charge a customer a demand charge covering distribution costs that applies to usage outside of these hours, and such a demand charge is not as accurate as a volumetric TOU charge at encouraging the reduction of non-coincident demand during the hours when those loads are the highest. A customer whose maximum demand occurs at 8 a.m. or midnight when the system is unloaded does not impose costs on the utility and should not be subject to a demand charge for that usage.

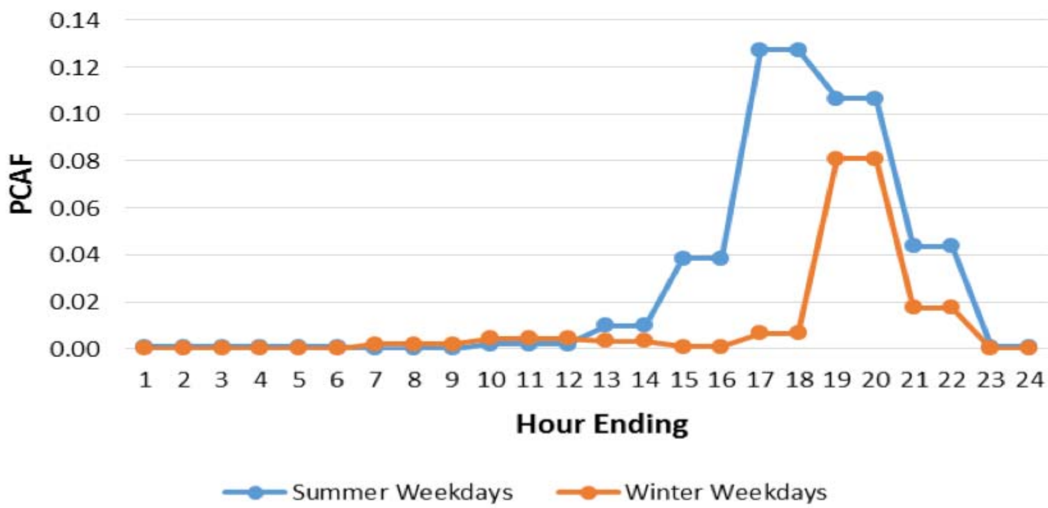
Figure 12. Distribution of 2009-2011 SDG&E Circuit Peaks by Hour Ending[113]



112 E3 presentation, *Overview of Public Tool to Evaluate Successor Tariff/Contract Options* (December 16, 2014), Slide 43.

113 From A. 14-01-027, *Prepared Rebuttal Testimony of David T. Barker on behalf of SDG&E – Chapter 3* (served December 12, 2014), p. DTB-6.

Figure 13. PG&E PCAFs Used in Public Tool: Weighted Average by DG Capacity in Each Climate Zone[114]



SCE's and ORA's proposed $/kWh charge based on the capacity of the installed system are not consistent with system-wide costing principles. Indeed, even SDG&E recognized that "unless the installed capacity charge has a direct relationship to utility cost of service, an installed capacity charge will not satisfy RDPs 2 and 3 [Commission Rate Design Principles 2 and 3],"[115] i.e. that rates should be based on cost causation principles. ORA readily acknowledges that its proposed Installed Capacity Fee (ICF) is in no manner a cost-based charge but is just a means of shifting revenues:

> The ICF is not a revenue neutral fee that substitutes a charge for a demand related revenue requirement that is currently recovered in an energy volumetric rate. Thus there is no commensurate reduction in other rate design elements and the utilities will credit the ICF revenues directly to residential electricity customers in rates.[116]

While SCE makes a valiant effort to tie its installed capacity charge to costs, it ultimately fails. SCE claims that "system size can be used as an accurate proxy for on-site displaced energy as well as a proxy of the amount of grid services the customer obtains to support and backup its own system,"[117] but all that SCE's associated analysis proves is that the utility is recovering less

114 To produce these weighted average PCAFs, the PCAFs for the various PG&E climate zones are weighted by the historical (through 2012) DER capacity installed in each zone.

115 SDG&E Proposal, p. A-26.

116 ORA Proposal, p. A-14.

117 SCE Proposal, Attachment 2, p. 1.

revenue as a result of the NEM customer's installation of solar, not that NEM customers are failing to pay for the cost of the infrastructure necessary to serve them.[118]

The Commission has wisely oriented its future rate design for residential and small commercial customers toward volumetric TOU rates, not rates with demand charges. Fundamentally, measuring a customer's "demand" is simply measuring its energy use over a different, shorter time period (for example, 15 minutes) than the standard measure of energy (one hour). Thus, a customer with a demand of 4 kW is really just using 1 kWh of energy every 15 minutes. From this perspective, there is nothing inherently more accurate with charging customers for demand (15-minute kW) than energy (kWh). Moreover, as noted above, it is more accurate to charge customers based on their time-of-use than based on their maximum demand that may occur in any hour, and, for solar customers in particular, it is likely that the customer's maximum demand will not occur on a hot, sunny, peak day. As referenced above, the Commission has approved all of the IOUs in California offering Option R rates with reduced demand charges and higher volumetric TOU rates for commercial and industrial (C&I) customers who install solar. In this regard, the Commission found that this is a more accurate way to assess capacity-related costs than a customer's maximum 15-minute demand.[119]

3. Imposition of a Disparate Rate Structure on NEM Customers Is Not Supported by the Public Tool's Claimed Cost-of-Service Metrics

The Public Tool includes metrics that allege to show the percentage contribution of NEM customers to each utility's cost of service. These metrics are flawed, and do not fully capture the contributions of NEM customers to the utility's cost of service. The Public Tool's cost of service metric has been defined as the <u>net</u> revenues from the NEM customer after installing DG divided by what the Tool calls the customer's "full cost of service."[120] However, significant elements of this "full cost of service" in the denominator are based on the NEM customer's total or gross load <u>before</u> installing DG. This includes T&D costs. In effect, basing a NEM customer's cost of service on his gross usage before installing DG amounts to a policy determination that a NEM customer cannot avoid or reduce the utility's T&D costs by installing DG. This aspect of the cost

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118 *Id.*, p. 5.

119 Decision 14-12-080.

120 See Slide 27 from E3's December 16, 2014 workshop presentation.

of service metric is thus inconsistent with the other tests in the Public Tool, which do allow a user to assume that NEM systems avoid T&D costs. Even more fundamentally, the Public Tool's cost of service metrics are inconsistent with the basic fact that the Commission establishes rates based on marginal costs for T&D which assume that a utility's T&D costs will change as a customer's kW demand or kWh energy use vary, for whatever reason including the installation of DG.

The Joint Solar Parties have requested repeatedly that the cost of service analysis in the Public Tool recognize and incorporate the ability to model whether a NEM customer's "full cost of service" should be based on its net or gross loads.[121] E3 recognized that this was an important issue in its 2013 NEM Study, where it included a "low case" based on an assumption that a NEM customer's cost of service should be based on its net loads, as shown in the table from that study presented below. Without such an option, the Joint Solar Parties do not believe that the Public Tool provides an accurate, equitable, or useful cost of service metric.

Table 25. Use of Net or Gross Loads in E3 2013 Report[122]

Marginal Cost Category	No NEM DG Case	Low Case	Utility Case	High Case
Generation Energy	Gross	Net	Net	Net
Generation Capacity	Gross	Net	Net	Net
Transmission (SCE)	Gross	Net	Net	Gross
Transmission (PG&E and SDG&E)	Gross Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through
Subtransmission (SCE)	Gross	Net	Gross	Gross
Distribution (SCE and SDG&E)	Gross	Net	Gross	Gross
Primary Distribution (PG&E)	Gross	Net	Gross	Gross
Primary New Business (PG&E)	Gross	Net	Gross	Gross
Secondary Distribution (PG&E)	Gross	Gross	Gross	Gross
Customer Cost	Gross	N/A	N/A	N/A

Net load is the account's hourly usage after it has been reduced by the DG output. Gross load is the account's hourly usage absent the DG. Net Load = Gross Load - DG Output.

121 *See* JSP April 28, 2015 Comments on the Draft Public Tool, pp. 8-9.

122 This is a reproduction of Table 44 in E3, *California Net Energy Metering Ratepayer Impacts Evaluation* (October 28, 2013), p. 92.

4. Short-Comings in the Adoption Module Exacerbate these Weaknesses in the Cost-of-Service Metrics

In addition to these problematic aspects of how the cost of service is calculated in the model, the JSPSs would also like to emphasize that the limitations of the adoption model and its bias toward large systems (discussed extensively in Sections III.A.3 and IV.B.2) further serves to limit the usefulness of the cost of service results. Given this bias toward large systems, customers under a NEM rate structure where the majority of systems offset 100% of their usage would be shown to contribute almost nothing towards the cost of service. In reality, the average system size is lower than 100%, and customers under a Full NEM framework would contribute much more than these modeling results show.

VII. OTHER SPECIFIC PROBLEMS WITH PARTIES' PROPOSALS

A. Proposals to Dramatically Curtail the Availability of VNEM and NEMA Are Inconsistent with State Law and Policy

The IOUs proposals regarding NEM Aggregation (NEMA) and Virtual Net Metering (VNEM) are inconsistent with state law and policy. The Legislature gave clear direction to the Commission to create a meter aggregation program by passing SB 594, with a substantial purpose being to enable the adoption of solar among agricultural customers. NEMA has just begun to gain traction in California, particularly for the economically disadvantaged agricultural community. The drought has had a devastating financial impact on the state's farming communities, and NEMA has enabled farmers to reduce a significant expense during this critical time of reduced revenue. Clean energy, with all of its benefits to air quality, employment, and carbon reduction, is essential to the economy of the Central Valley.

VNEM was developed in response to the legislative directive that not less than 10% of overall CSI funds be used for installation of solar energy systems on "low-income residential housing."[123] As thoroughly explained in the CALSEIA successor tariff proposal, the Commission has cautiously expanded VNEM to gradually increase access to renewable generation by residents of all types of multifamily housing.

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123 Enabling legislation included AB 32 (2006) and SB 1018 (2012), which the Commission implemented in D.12-12-033.

With the exception of two limited situations in the context of the MASH program for low-income customers and for agricultural customers, PG&E proposes that virtual and aggregated net metering be eliminated.[124] SCE also proposes that such programs be eliminated except in the context of the MASH Program and for renewable DG for residential customers in disadvantaged communities.[125] SDG&E proposes continuation of NEMA and VNEM.[126] In all cases in which the utilities propose continuing NEMA and VNEM, they would value credits at the rate proposed for the standard successor tariff, which would undermine their intended purpose.

PG&E asserts that, under AB 327, “there is no legislative requirement that the CPUC incorporate any of the various forms of virtual net metering that have been created by either the legislature or the CPUC,”[127] yet PG&E cannot point to any statutory language indicating an intention by the Legislature to reverse its previous direction to the Commission to maintain a meter aggregation program and programs designed for multifamily housing.

Moreover, SCE’s and PG&E’s claims that they are proposing to continue to offer NEMA to a certain segment of their customer base and SDG&E’s claim that it will continue to make NEMA available to all qualifying generators are misleading.[128] The whole concept of meter aggregation and virtual net metering is to treat the combined consumption of multiple meters as one load. If the electrical production at the generating account is not credited at the full rate for the benefitting accounts, it is pointless to have benefitting accounts. The Legislature created NEMA because farms often have multiple electrical service accounts but the area around each meter is not always suitable for solar and farmers can save money by installing one solar system rather then multiple smaller systems. If the credits are not shared among the accounts as if the

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[124] PG&E Proposal, p. 29.

[125] SCE Proposal, p. 38.

[126] SDG&E Proposal, pp. A-73-A-75.

[127] PG&E Proposal, p. 29.

[128] PG&E Proposal, p. 31: “PG&E would support continuation of the ability to aggregate accounts for agricultural customers, so long as the exports are only credited at the generation component of the retail rate”; SCE Proposal at 39: “SCE recommends that … all exported kWh be valued at the ECR”; SDG&E Proposal at A-75: “customers would no longer receive an aggregated portion of the generation to offset their consumption but would instead receive credits based on allocated share of generation priced at the Sun Credits rate.”

accounts were one combined load, the program would not achieve its statutory purpose.

PG&E proposes that, in NEMA, "the allocation from the generating account to the benefitting accounts would be determined by the customer, not based on the monthly usage of the individual benefitting accounts."[129] Allowing customers to choose their own allocations for NEMA billing makes NEMA unnecessarily complicated. Having the default allocation remain as it is (based on usage of the different meters) would more accurately avoid credits going unused by customers.[130]

The IOUs' proposals to continue VNEM for MASH are similarly disingenuous. PG&E states it is proposing to continue VNEM for purposes of "extending the benefits of rooftop solar to low income customers, who would not otherwise be able to take advantage of renewable generation programs," but PG&E proposes to reduce credits to the generation rate, and the other IOUs also propose credits at lower export rates.[131] MASH projects would not be viable if credits were discounted. In D.15-01-027, the Commission considered the level of subsidy necessary to enable solar installations at multifamily housing properties, with a limited program budget and a statutory adoption target. It was necessary to set incentives high enough to facilitate adoption and low enough to stretch the funding and meet the target. In setting this incentive level, the Commission assumed the VNEM tariff would be available with credits at the full retail rate. Reducing the credit would spoil the balance and make the program unworkable.

D.15-01-027 implemented AB 217 of 2013, which reauthorized the MASH program through 2021. AB 327, directing the Commission to create a NEM successor tariff, was also passed in 2013. It is illogical that the Legislature directed the Commission to continue a program that relies on VNEM and at the same time envisioned changes to VNEM that would make it unworkable.

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129 PG&E Proposal, p. 31.

130 The JSP have no objection to the IOUs introducing a voluntary option to allow customers to manually allocate at their election.

131 PG&E Proposal, p. 30 ("All participating customers, however, would need to be on the successor tariff for CARE"); SCE Proposal, pp. 38-39 ("SCE's support is contingent, however, upon these customers receiving the ECR proposed in SCE's Proposal, as opposed to full retail rate credits"); SDG&E Proposal, p. A-73 ("customers would no longer receive an allocation of the generation to "virtually" offset their consumption but would instead receive credits based on allocated share of generation priced at the Sun Credits rate").

B. SDG&E's Proposal to Close Option R Is Not Supported

With no supporting explanation, SDG&E proposes to close Schedule DG-R to new NEM customers, with the exception of public K-12 schools.[132] Schedule DG-R is a voluntary option for qualifying non-residential DG customers that affords them reduced demand charges.[133] SDG&E's proposal, which would serve to strike another substantial blow to customer-sited renewable DG, must be rejected.

Schedule DG-R was first approved by the Commission in Decision 08-02-034, as part of a settlement agreement of SDG&E's 2007 GRC Phase II (A. 07-01-047). In Decision 14-01-002, the Commission rejected a contested settlement that would have modified DG-R, noting the assertion of certain parties that in making their solar investments, they relied on the economics of Schedule DG-R and that the proposed modifications to DG-R would "decimate" the economic assumptions.[134] Moreover, the Commission noted that SDG&E "has not established precisely how the existing DG-R rate is flawed."[135] The same omission exists here. This omission is glaring in light of the fact that the Commission has recently reviewed the basic rationale for rates with reduced demand charges for C&I customers that install solar, such as the SDG&E DG-R rate, and found that such rates were cost-justified.[136]

Moreover, the record of this case illustrates that the continuance of Schedule DG-R will not add to the rate impacts of NEM on non-participating customers. Even assuming that all future eligible C&I solar customers in SDG&E's service territory elect Schedule DG-R rates, the RIM Test result for the C&I class is a benefit/cost ratio of 1.0.[137]

C. Fixed Charges Would Discourage Desired Behavior

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132 SDG&E Proposal, p. A-53.

133 The rates for Schedule DG-R recover all generation costs on a volumetric basis, with no generation demand charges. Schedule DG-R rates also include a distribution maximum demand charge set at 50% of the equivalent maximum demand charge for other commercial schedules, with the remaining distribution costs for Schedule DG-R recovered through a "flat" (non-time varying) energy charge.

134 *See* D.14-01-002, p. 31.

135 *Id*, p. 34.

136 *See, e.g.*, D.14-12-080 at pp. 5, 20-12.

137 *See* Solar Parties Proposal at p. 36-37.

The SCE and ORA proposals include significant monthly fixed charges that would be based on the installed capacity of the DG system. SCE and ORA propose fixed charges intended to reduce what they believe are the non-participant impacts of NEM. The Commission knows well the infirmities of fixed charges for residential rate design, having just concluded an extensive debate in R. 12-06-013 on the merits of fixed charges as part of residential rate design. In that docket, the IOUs' own customer survey definitively showed solid customer opposition to fixed charges that only increased after the customers were educated on the potential impact that a fixed charge would have on their bill.[138] This increase in opposition was unsurprising given the fact that the utilities' own educational materials indicate that a fixed charge "can reduce your ability to save money by lowering your usage or shifting your energy use…"[139] The fundamental problem with fixed charges is, of course, that they provide the customer with no incentive to take actions that might reduce the costs that are collected through the fixed charge. A NEM customer has the same ability as any other customer to impact the costs that its usage imposes on the system, by changing the profile of its load. A NEM customer that reduces its on-peak load, for example, will reduce its impacts on non-participating customers, by lowering its net load and reducing the generation, transmission, and distribution costs which its net usage imposes on the system. But if those non-participant impacts are collected through a fixed charge that is based on the fixed size of the solar system, any such incentive or ability for the NEM customer to reduce its impacts on non-participants is removed. The NEM customer surely will view such an unavoidable charge as a "tax" or "penalty" for supporting the state's clean energy goals.

The Commission's decision in the Residential Rate Design OIR accurately depicts the significant problems with customer acceptance of fixed charges:

- "In this proceeding, the record demonstrates that customers have expressed their opposition to fixed charges in comments, at PPHs, through customer surveys, and in previous rate proceedings."[140]

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138 *See, e.g.* TASC Opening Brief (R. 12-06-013), filed January 5, 2015 pp. 21-22.

139 *See* TASC Exhibit-103, "Educational Materials provided as part of the Hiner Study", p. 14.

140 Decision 15-07-001, p. 214.

- "… the record demonstrates that customers tend to believe that the fixed charge would be an additional charge."[141]
- "Based on the record in this proceeding, it is very clear that customers are unlikely to understand or accept the need for fixed charges without customer education. Combining a new fixed charge with other significant rate design changes would only exacerbate the issue."[142]

Customer opposition to fixed charges for NEM customers will be exacerbated by the fact that, to an extent, DG represents a competitive option to utility service. In the long-run, as DG and storage technologies mature and their costs fall – and, paradoxically, as DG/storage become more valuable to the grid and the utility system – fixed charges will only encourage customers to consider "cutting the cord" with the grid entirely. The JSPS do not believe that this is the direction in which the Commission should head.

The Commission's Residential Rate Design decision declined to adopt a fixed charge at this time as part of the Commission residential rate design reforms.[143] At most, the Commission indicated that "a fixed charge representative of fixed customer-related costs could have an important role in residential rate design" at some point in the future, after default TOU rates are adopted and implemented.[144] The Commission also noted that the IOUs' proposed fixed charges were not consistent with a number of RDPs.[145] To the extent the Commission believes the residential rates RDPs are relevant to the current proceeding, SDG&E misapplies them in a self-serving manner to justify fixed charges on self-generating customers despite the fact that the

141 *Id.*, p. 215.

142 *Id.*, p. 216.

143 *See Id.*, p. 273 ("PG&E failed to justify its proposed fixed monthly charge"); *Id*. at p. 283 ("SCE failed to justify its proposed expansion of its fixed monthly charge."); *Id.* at p. 290 ("SDG&E failed to justify its proposed fixed charge.").

144 *Id.*, pp. 216-217.

145 *See*, *e.g.*, *Id.*, pp. 215-16 ("As is reflected in RDP 10, we want to ensure that customers understand and accept residential rate structures, and that rates are stable and understandable. . . . The record in this case demonstrates that customers are concerned about fixed charges. In light of this concern, and in the interest of adopting a roadmap that includes stable and understandable rates, we find that it is reasonable to defer consideration of fixed charges . . . Consumer acceptance and understanding is incorporated into the rate design principles in this proceeding, including RDP #6 and RDP#10.")

Commission pointed to the RDPs in rejecting fixed charges in the RROIR proceeding.[146] The JSPS agree that NEM customers cannot avoid customer-related costs such as metering, billing, and customer-service costs, and should be subject to any fixed charge to cover such costs that the Commission ultimately may adopt. However, such customer-related fixed costs are very limited. TURN, ORA, and other parties in R. 12-06-013, for example, believe that they could be less than AB 327's statutory maximum of $10 per month.[147] The Commission has not found that any costs beyond customer-related costs are truly fixed, such that they should be collected through a fixed charge.[148] The policy reasons for this conclusion apply to NEM customers as well as regular utility customers as a matter of law in order to avoid discriminatory treatment. Thus, the Commission should reject NEM successor tariffs that are based on high fixed charges, which future NEM customers will have no ability to impact and will perceive as an unjustified, anti-competitive tax on the very clean energy infrastructure that customers believe state policy should encourage.

D. Monthly Netting Would Increase Confusion and Thereby Undermine Customer Adoption

PG&E has proposed to change the current practice of "annual netting," whereby NEM customers are allowed to carry forward bill credits from month-to-month, subject to an annual true-up. PG&E would change this annual netting into a monthly true up. Such a proposal not only directly contravenes Section 2827 (h)(3), but it will significantly reduce bill savings for larger customers and result in customer confusion.

At present, PG&E zeros-out bill credits only if the NEM customer has credits remaining at the end of the annual period. If during the annual period the customer has exported to the utility more kWh than it has consumed from the utility, then the customer receives a "net surplus compensation" (NSC) payment from the utility for the "net surplus" power – the excess of exports over imports for the year. This process is consistent with Section 2827 (h)(3), which requires an annual netting period.[149] NSC payments are made pursuant to AB 920, which

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146 *See* SDG&E Proposal, pp. A-27 – A-28.

147 *Id*, pp. 212-213.

148 Decision 96-04-050, p. 113; Decision 15-07-001, p. 216 and Finding of Facts 162, 163, and 171.

149 Section 2827 (h) (3) provides that "at the end of each 12-month period, where the electricity

modified P.U. Code Section 2827, and D.11-06-016 implementing this statute. There is nothing in AB 327 that indicates the Legislature intended any change to be made in the current NSC practices, and PG&E has provided no statutory basis for changing NSC from an annual to a monthly calculation.

PG&E's monthly netting proposal would have the principal impact of significantly increasing the amount of power compensated each month at the low NSC rate (4 c/kWh),[150] thus reducing the amount of exports that PG&E would credit at the generation component of its retail rate (9.7 c/kWh). PG&E would apply the low NSC rate to any kWh of exports that exceed the kWh of imports in a month. This would be most significant for NEM customers who have large systems that seek to serve at or close to 100% of their usage. For these large customers, we calculate that PG&E's monthly netting accounts for about 11% of the reduction in bill savings from PG&E's proposal, compared to NEM at the full retail rate under E-1. The remaining 89% of the reduction in bill savings would be due to the lower 9.7 c/kWh export rate and PG&E's proposed new demand charge. Monthly netting would become a much bigger issue if PG&E were to retain full retail NEM or offer a higher export rate. If the compensation structure were a full retail rate credit, there would be significant surplus monthly credits lost under monthly netting.

In addition to the reduced bill savings for customers with larger DG systems, monthly netting would enhance customer confusion – exactly the opposite of PG&E's stated justification. PG&E's proposal requires a monthly division of exports between those that qualify for the full 9.7 c/kWh export rate and those that would be paid just the 4 c/kWh NSC rate. Whether a customer qualifies for NSC is already confusing, and PG&E's monthly netting proposal makes

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generated by the eligible customer-generator during the 12-month period exceeds the electricity supplied by the electric utility during that same period, the eligible customer-generator is a net surplus customer-generator and the electric utility, upon an affirmative election by the net surplus customer-generator, shall either (A) provide net surplus electricity compensation for any net surplus electricity generated during the prior 12-month period, or (B) allow the net surplus customer-generator to apply the net surplus electricity as a credit for kilowatthours subsequently supplied by the electric utility to the net surplus customer-generator."

150 Pursuant to Decision11-06-016, the NSC compensation rate is based on short-run CAISO market prices plus a small adder for the RECs associated with this renewable generation. Because NEM systems are required to be sized no bigger than needed to serve the customer's historical loads, the volumes of net surplus energy for which NSC payments are made are minor.

this a monthly issue, rather than an annual one, and makes it applicable to many more customers, compared to today when only a few customers qualify for NSC on an annual basis.

E. PG&E's Views on Solar Pricing in California Are Simplistic and Should Be Ignored

In support of their proposal, PG&E argues that current polices enable value-based pricing. PG&E's argument is simplistic as it does not recognize that many factors contribute to pricing differentials among states. Differences in pricing between states was recently discussed in LBNL's 8th annual "Tracking the Sun" report which was released in August 2015. In that report, the authors note:

> Cross-state installed pricing differences can reflect a wide assortment of factors, including installer competition and experience, retail rates and incentive levels, project characteristics particular to each region, labor costs, sales tax, and permitting and administrative processes.[151]

The *Tracking the Sun VIII* report provides detailed discussion on variations in solar pricing across the United States and in comparison to other countries. While "value-based" pricing is one factor discussed in the report, the report clearly notes that other factors are involved including project characteristics, attributes of individual installers, prevailing electric rates, level of competition in the market, and administrative and regulatory compliance costs among others, and the authors spend over 16 pages discussing various factors.[152] PG&E's self-serving analysis should be dismissed by the Commission as it simply does not capture the full spectrum of reasons why costs may differ among states or installers.

F. PG&E's Characterization of the Findings of Its Focus Group Studies Is Inaccurate and Misleading

In support of PG&E's proposal to end annual true up and move to monthly billing, PG&E mentions in footnote 36 that it has engaged in customer focus group research and states that the research shows that "[NEM customers] are often are often caught by surprise when they get their first true-up bill, with some having difficulty paying large true-up charges. In addition, many customers, including veteran NEM customers, do not understand how net metering works."

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151 *See* Tracking the Sun VIII , p. 3.

152 *See* Tracking the Sun VIII, pp. 25-41.

However, review of materials that TASC obtained from PG&E during discovery demonstrates that PG&E's focus group research findings do not support these statements. In fact, careful review of PG&E's focus group research shows that while some NEM customers note surprise during their *initial* true-up, *they subsequently manage the process and believe that going solar is working well for them and that they've changed their behavior to decrease their electric consumption.*[153] (emphasis added) Moreover, when focus group participants were presented with an option to have a monthly true-up or an annual true up, many participants stated they wanted to stay on an annual true up as they understood solar production was variable during the year so they wanted the entire year to balance out their production. The focus group participants also felt that different payment options may have merit only so long as it was an option to how they are currently paying for their monthly bill and not required by PG&E. In sum, these statements stand in stark contrast to PG&E's characterization of the findings of this focus group research.

VIII. IT IS ILLEGAL AND UNNECESSARY TO FORCE SOLAR CUSTOMERS ONTO A "BUY-ALL/CREDIT-ALL" ARRANGEMENT TO ADDRESS CONCERNS REGARDING COST-SHIFTING

TURN proposes a "Value of Distributed Energy" (VODE) tariff under which customers would be charged for their gross consumption at the applicable retail rate and compensated for their gross generation at a rate based on the "value of onsite renewable generation to the utility and non-participants."[154] Under TURN's "buy-all/credit-all" (BACA) approach customers would meet all onsite load with electricity purchased from their utility and be compensated separately for all onsite generation. The Joint Solar Parties have a number of substantial concerns with TURN's proposal.

A. TURN's Proposal Violates Federal Law

A program requiring customers to enter into a BACA framework with their utility violates federal regulations under PURPA because PURPA grants customers the right to serve

153 PG&E has designated this portion of their response to TASC's data request as confidential and proprietary so we are unable to reference the specific statements contained within the focus group report that TASC obtained from PG&E in response to TASC's data request. For the time being, in the interest of conserving party resources, TASC has not sought review by the Commission of whether this designation is appropriate.

154 TURN Proposal, pp. 1, 3.

their onsite load before selling the excess generation to the utility. Under these regulations, a qualifying facility (QF) has the option either "(1) to provide energy as the *QF determines such energy to be available for such purchases* . . . or (2) to provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term."[155] QFs also have the right to operate in parallel with the utility's system.[156] As a result, it is the QF's (i.e. the DG customer's) right to determine whether to sell all of its output, or just the excess generation, to the utility. TURN's proposal would deny customer-generators this fundamental right to serve their on-site load and to determine how much energy to make available to their utility, and therefore runs afoul of PURPA. Furthermore, because TURN's proposal is not justified based on any cost of service showing, it violates fundamental aspects of federal and state law prohibiting discrimination against qualifying facilities and utility customers generally, as noted above. It is simply not sufficient to argue that revenue reduction justifies this proposal. Rather, a substantial showing that the costs to serve customer-generators are different than the costs to serve other residential customers is needed before the Commission can find the proposed charges just and reasonable under applicable state law and federal law.

B. TURN's Proposal Is Premised on Commission Jurisdiction Which Does Not Exist, Violates A Customer's Right to Privacy, and Would Result in a Regulatory Takings

TURN's BACA proposal also suffers from a number of equally significant legal infirmities based on California constitutional and state law. TURN's BACA proposal is predicated upon a strained belief that the Commission has jurisdiction to look behind the customer meter to dictate the use of the customer's private property for the benefit of a third-party, in this case the utility. This unlimited view of the Commission's jurisdiction is at odds with well-settled California constitutional law and statute. Under the California Constitution, the Commission's jurisdiction is limited to "private corporations and persons" acting as public

155 18 CFR § 292.304(d) (emphasis added).

156 18 CFR. § 292.303(e) (all utilities must offer parallel operation); FERC Staff Memorandum on Order 69, 44 FR. 38863, at 38869 (July 3, 1979) (explaining that § 292.303(e) provides QFs an "entitlement" to operate in parallel with utilities "so that the same customer circuits can be served simultaneously by both customer- and utility-generated electricity").

utilities as defined by the California Legislature.[157] Owners of distributed generation are not public utilities as their facilities have not been dedicated to public use[158] and owners of distributed generation are specifically exempted from being public utilities under statute.[159] Moreover, third-party solar providers have been expressly exempted from regulation as public utilities.[160] Commission jurisdiction over third-party solar providers that was expressly granted under Section 2869 was predicated on the provision of direct incentives to the solar provider.[161] Because the California Solar Initiative has ended, direct incentives are no longer being provided to third-party solar providers, so the limited jurisdiction the Commission had pursuant to Section 2869 has sunset. Based in these facts, the JSPSs do not believe the Commission has the jurisdiction to look behind the customer meter to control how they use their private property for their own benefit, other than to ensure that the customer's equipment operates safely in parallel with the grid.

Furthermore, implementation of TURN's proposal would require the installation of a second meter, a situation that is unnecessary now under NEM. The cost of a second meter can vary widely based on the particulars of a customer's electrical service. Imposing this cost on customers merely to implement an unnecessary VOST framework works at cross purposes with ongoing efforts in this state stretching back since the Emerging Renewables Program was created to *lower* the cost of a customer's decision to invest in renewable energy resources.[162] The NEM statute's ban on second meters may still hold today, and therefore TURN's proposal cannot be implemented, since the installation of a second meter must be done "with the consent of the eligible customer-generator," and then only to provide information necessary to accurately bill the customer, or for research purposes.[163]

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157 Cal. Const. Art. XII, Sec. 3 and 5.

158 Story v. Richardson, 186 Cal. 162, 167-68 (1921).

159 *See* Cal. Pub. Util. Code § 218(b)(1)

160 *See* Cal. Pub. Util. Code § 218(e).

161 *See* Cal. Pub. Util. Code § 2869.

162 SDG&E's SunCredit proposal similarly would require a second meter at additional cost to a customer which runs counter to state policy efforts. This additional, unnecessary cost represents another reason to deny approval of the SunCredit proposal.

163 Cal. Pub. Util. Code § 2827(c)(1) ("Net energy metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions. An additional meter or

Additionally, the Joint Solar Parties believe TURN's proposal would result in a regulatory taking as it would completely remove a customer-generator's ability to use their private property to supply power on-site to instantaneously serve their load. Instead, TURN would require all of the output from such property to be sold either directly or implicitly to the utility at an administratively determined credit rate. Under the Fifth Amendment of the United States Constitution, "private property [shall not] be taken for public use without just compensation."[164] The California Constitution similarly states that, "Private property may be taken … for a public use and only when just compensation, ascertained by a jury unless waived, has first been paid to . . . the owner."[165] Whether or not the level of compensation is just is based on the value of the property to the owner, in this case, the customer-generator.[166] The existing retail rate is a fair measure of that value to the customer-generator. Although TURN's proposal would compensate participating customers for the generation they instantaneously consume on-site, it would do so in the form of credits based on the value to the utility and non-participants, not the value to the customer itself.[167] The value TURN proposes is less than the full retail rate the customer avoids when engaging in self-supply, which is the value enshrined in federal law. As a result, the proposal could amount to inadequate compensation for the mandatory sale of a customer's instantaneously consumed generation.

Finally, customers have a right to privacy in their use of private property behind their meter, a right protected by Article 1, Section 1 of the California Constitution.[168] This privacy right remains in its full effect in the instant situation given the lack of jurisdiction for the

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meters to monitor the flow of electricity in each direction may be installed with the consent of the eligible customer-generator, at the expense of the electric utility, and the additional metering shall be used only to provide the information necessary to accurately bill or credit the eligible customer-generator pursuant to subdivision (h), or to collect generating system performance information for research purposes relative to a renewable electrical generation facility.").

164 U.S. Const. amend. V.

165 Cal. Const., Art. I § 19.

166 Boston Chamber *of Commerce v. Boston*, 217 U.S. 189, 195 (1910); *Brown v. Legal Found.*, 538 U.S. 216, 235-36 (2003).

167 TURN Proposal , p. 1.

168 Cal. Const., Art. I, § 1 ("All people are by nature free and independent and have inalienable rights. Among these are enjoying and defending life and liberty, acquiring, possessing, and protecting property, and pursuing and obtaining safety, happiness, and privacy.").

Commission to impose TURN's proposal upon customer-generators. The lack of any safety or reliability concerns stemming from the customer's use of customer-sited DG[169] also supports the view that well-settled expectations of privacy should be maintained behind the customer meter. Simply put, TURN does not even attempt to grapple with the invasion of privacy its proposal would represent. Rather than trying to enforce an economic arrangement between a customer-generator and their utility that has no underpinning in the reality of the way the customer's system is utilized or impacts the grid, the Joint Solar Parties believe respecting a customer's privacy is part and parcel of promoting the exact type of customer engagement needed to ensure success in demand-side programs.

C. TURN's BACA Proposal Raises Significant Tax Uncertainty Which Will Undermine Customer-Sited Renewable DG Adoption

Unlike NEM, TURN's BACA proposal also raises a number of significant tax concerns.[170] Under TURN's proposal, customers would export all of the electricity they produce onsite to their utility, which the utility would then sell to other ratepayers.[171] Tax analysis performed for The Alliance for Solar Choice by Skadden, Arps, Slate, Meagher & Flom LLP (Skadden Memo) raises serious concerns that implementation of such a proposal may jeopardize access to federal tax incentives and could result in unforeseen income tax liability for consumers receiving payments or credits under such an arrangement.[172]

As discussed in more detail in the attached Skadden Memo, residential solar configurations such as feed-in tariffs and value of solar tariffs (VOST), which are buy-all/sell-all

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169 Safety and reliability concerns are adequately addressed by Rule 21 tariffs for each IOU.

170 SDG&E at pages A-88 – A-90 of its proposal attempts to create tax uncertainty regarding NEM crediting noting that there may be income tax owed on NEM credits. However, despite paying out NEM credits since the start of the NEM program, SDG&E has not issued 1099s to NEM participants so it is clear that SDG&E's discussion is nothing more than an attempt to create uncertainty where the likely is none. Moreover, despite hundreds of thousands of systems being installed nationally, the Joint Solar Parties are unaware of any federal or state income tax issues related to NEM. While SDG&E points out that the Edison Electric Institute (EEI) has requested that the U.S. Treasury review the income tax implications of net metering, SDG&E fails to acknowledge that the U.S. Treasury declined EEI's request.

171 *See* TURN Proposal, pp. 1, 3-4.

172 *See* Skadden, Arps, Slate, Meagher & Flom LLP, *Memorandum RE: U.S. Federal Tax Consequences for Residential Solar Feed-In Tariffs*, (Aug. 9, 2013) (Appendix D) (hereinafter Skadden Memo).

or buy-all/credit-all mechanisms, jeopardize access to the 30% Residential Income Section 25D tax credit as the energy generated by the customer's system may not be deemed to be used directly on-site. The Skadden Memo also concludes that payments received by a taxpayer under such configurations are likely includable in a taxpayer's reported taxable gross income and therefore subject to state and federal income taxation, regardless of whether they are called "credits" or "payments."[173] Additional analysis by Chadbourne & Parke LLP concerning the tax consequences of feed-in tariffs reached similar conclusions, as did analysis performed by Chun Kerr LLP regarding the tax implications of feed-in-tariffs in Hawaii.[174] Moreover, the IRS is actively considering whether any current VOST program would result in these two outcomes. The Joint Solar Parties recognize that these memorandums are not specific to California and is working to provide California tax specific analysis so that the Commission has solid analysis upon which it can rely in assessing the uncertainties in tax treatment that TURN's proposal will create.

The analysis provided by TURN in support for their proposal should not be relied upon by the Commission as the drafter of that analysis makes clear that they are not tax attorneys or even tax professionals.[175] Thus the author does not contain the requisite expertise to assess accurately the tax implications of TURN's proposal. This lack of expertise stands in stark contrast to the authors of the memorandums discussed above who are tax attorneys able to provide tax advice. The author also clearly notes that the analysis offered is merely a policy and technical review. Thus the author does not address the core tax issues attendant under a BACA framework in the manner necessary for the Commission to address the concerns these proposals present in a definitive manner. Additionally, the author clearly states: "Tax payers and others seeking tax advice should consult with a professional tax advisor." This disclaimer makes clear that the advice being offered cannot be relied upon in forming any judgment as to the tax consequences of a VOST framework while simultaneously highlighting the very point the Joint Solar Parties are making, namely, that a VOST arrangement raises tax issues which will only

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173 Skadden Memo, pp. 2-3.

174 *See* Chadbourne & Parke LLP, *Memorandum RE: Residential Solar Feed-in Tariff Programs*, (June 26, 2015) (Appendix E) Chun Kerr LLP, *Memorandum RE: Residential Solar Feed-in-Tariffs – Hawaii income and general excise tax*, (June 1, 2015) (Attachment E).

175 *See* TURN Proposal, Attachment 2.

serve to increase the uncertainty a customer faces when receiving credits under such a framework.

Given the legal infirmities and uncertain tax implications of TURN's BACA proposal, the Joint Solar Parties' believe the Commission should dismiss the proposal from further consideration. AB 327 charges the Commission with ensuring that "customer-sited renewable generation continues to grow sustainably."[176] Market certainty and stability are critically important to the sustainable growth of the solar industry because the investment community needs to understand the risks involved in providing the necessary capital to support customer-sited distributed generation investments. Customers considering an investment in distributed generation need to understand the financial benefits of their investment with a reasonable level of certainty. BACA arrangements, such as TURN's, simply do not provide this certainty and sustainability because of the concerns noted above. When risk increases, investors demand increased returns, which increases prices and reduces adoption. Such a substantial deviation from the current NEM program could significantly impact customer and investor confidence in customer-sited renewable generation, and these adverse impacts would likely only be aggravated by transitioning to a program with uncertain tax ramifications for the customer.

IX. FUTURE CONSIDERATIONS OF CHANGES TO TARIFF

The IOUs all propose that the adopted NEM successor tariff, or certain portions thereof, be reviewed by the Commission on a periodic basis and be subject to change.[177] The Joint Solar Parties do not dispute the fact that there may be need to be refinements to the tariff subsequent to its adoption, but submit that there is no need for the Commission to establish a periodic review process at this juncture. The Commission retains the authority to open a proceeding to reassess the IOUs' NEM tariffs at any time. Moreover, if a party believes that a change in circumstances since the adoption of the tariff necessitates a modification, then it can file a petition for

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

[177] PG&E proposes that the Commission's next review of the successor tariffs be initiated in 2019 or once total, statewide NEM installations reach 7,800 MW. *See* PG&E Proposal p. 28. SCE proposes that the Commission reassess elements of its NEM tariff every three years as part of its GRC.

modification of the Commission decision adopting the tariff, and the Commission can act accordingly.

If, however, the Commission determines that, as part of approving a NEM successor tariff, it must establish a period review process, then the Joint Solar Parties request that such a process be balanced with the market's need for regulatory certainty. In this regard, the Commission should determine that the effective date of any changes to the NEM tariff's fees or compensation made in a subsequent proceeding will not be effective until at least one year after the date of the decision approving the new fee or compensation. This is necessary to allow customers that have committed to solar investments but have not finished construction to complete their investments without having the rules changed midstream. Such directive is consistent with the action taken by the Commission in D.15-08-005, allowing a 17-month transition period prior to the reduction of the kW eligibility limit for PG&E's A-6 rate schedule, a period which allowed solar customers who determined to invest in solar based on their eligibility for that rate schedule to "complete their investment as planned."[178]

In addition, the Commission should determine that any changes to the NEM tariffs made in subsequent proceedings will not apply to systems already installed when the change becomes effective. Customers who install solar on the basis of the successor NEM tariff adopted in this proceeding should not see that investment undermined by subsequent changes to that tariff. The Commission has previously recognized the need to vintage NEM customers in the NEM tariff under which they initially took service when, in R.12-11-005, it adopted a 20-year period for current NEM customers to transition to the successor NEM tariff. Thus the Commission ruled that:

> Adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation.[179]

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178 Decision 15-08-005.

179 Decision 14-03-041, p. 20.

X. SYSTEMS LARGER THAN 1 MW

AB 327 removes the limit on NEM participation for systems larger than 1 MW "that do not have significant impact on the distribution grid."[180] SCE and SDG&E seek to define "significant impact" based on whether a system qualifies for Fast Track approval under Rule 21.[181] These proposals effectively place a cap on system size, since the utilities' Rule 21 tariffs set size limits for systems to qualify for Fast Track approval. For instance, SCE and PG&E both have 3.0 MW caps and SDG&E has a 1.5 MW cap on Fast Track eligibility for exporting systems.[182] The result is that proposals that tie NEM participation to Fast Track eligibility would cap the system size for NEM participation at 3.0 MW for SCE and PG&E and only 1.5 MW for SDG&E.[183] Rather than remove the cap on systems larger than 1 MW and genuinely assess whether these systems have significant grid impacts, these proposals seek merely to replace the 1 MW cap with a slightly larger one. In doing so, these proposals appear to plainly contradict the intent of AB 327 which directs the Commission to allow systems larger than 1 MW to qualify for the successor tariff under specified conditions, not to meagerly increase the 1 MW cap to only 1.5 MW.

Rather than impose a strict cap on system size, the grid impacts of systems larger than 1 MW actually should be assessed. ORA argues that systems larger than 1 MW should be required to "demonstrate that they do not have a significant impact on the distribution grid and will not require distribution upgrades to mitigate reliability concerns."[184] However, in the event a system poses a significant grid impact, the system owner should have the opportunity to pay for any upgrades needed to eliminate that impact. In other words, to the extent systems require upgrades to mitigate impacts and system owners are willing to pay for those upgrades, the system would not have an impact and should be allowed to participate in NEM.

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180 Cal. Pub. Util. Code. § 2827.1(b)(5).

181 *See* SCE Proposal at p. 35; SDG&E Proposal, Appendix A at p. A-70.

182 SCE Rule 21 Tariff, Sheet 34; PG&E Rule 21 Tariff, Sheet 44; SDG&E Rule 21 Tariff, Sheet 25.

183 PG&E Rule 21 Tariff, Sheet 44.

184 ORA Proposal, p. A-25.

SDG&E argues that in order to ensure systems larger than 1 MW are sized to onsite load,[185] "the nameplate capacity of a NEM system should be no larger than the maximum demand of the customer over the past 12 months."[186] This proposal is unnecessary and inconsistent with the current and longstanding practice of basing onsite load on annual kWh usage. A customer that has a maximum demand of 2 MW and a load factor of 40% will only be able to serve 50% of its on-site load with a 2 MW solar array that operates at a 20% capacity factor. SDG&E's proposal thus would not allow NEM projects larger than one MW "to be built to the size of the onsite load" as required in Section 2827.1(b)(5) and as system sizing for onsite DG has been implemented for many years.

XI. CONSUMER PROTECTION

One of the most important aspects of consumer protection is creating an environment in which consumers can expect to obtain reliable information from the marketplace. As described in Section IV.D, the successor tariff proposals of other parties would introduce uncertainty and variability that would make it more difficult for vendors to project customer savings consistently. Maintaining a straightforward and well-understood net metering structure would help ensure that consumers receive clear information upon which they can base their long-term financial decisions.

The IOUs and TURN all request Commission oversight of the solar industry that goes beyond the Commission's jurisdiction. SCE states that, "Regardless of the type of entity, the Commission has the authority to impose consumer protections over entities engaging in activities under Commission-approved and regulated utility programs."[187] However, as discussed previously, the Commission has very limited jurisdiction over the solar industry and its participants.[188] This jurisdiction is limited to requiring additional disclosure requirements only when direct ratepayer incentives are provided.[189] Broad proposals for establishment of a process

185 *See* Cal. Pub. Util. Code § 2827.1(b)(5).

186 SDG&E Proposal, Appendix A, pp. A-70 - A-71.

187 SCE Proposal, p. 44.

188 *See* Joint Solar Parties Reply Comments (March 30, 2015), p. 18.

189 *See* Cal. Pub. Util. Code § 28698(a)(2).

for the Commission to review non-utility-related consumer complaints,[190] establishment of financial responsibility and safety standards,[191] and other similar proposals simply fail to recognize the Commission's limited authority.

Nonetheless, SCE and other parties advocate for imposing extensive measures on self-generation service providers. These include standardized disclosure requirements,[192] extending Commission jurisdiction over customer complaints against market participants, and financial responsibility and business practice standards.[193] None of these proposals are based on a careful analysis of the Commission's jurisdiction or any showing that any of them are necessary. As discussed extensively in our March comments, the solar industry takes consumer protection very seriously and has worked diligently and consistently with stakeholders to address consumer protection concerns. In the instant context, the Joint Solar Parties are supportive of the use of Approved Equipment Lists maintained by the California Energy Commission (CEC), as these can be important resources for ensuring the safety and reliability of the equipment that consumers and installers choose to utilize. We were pleased to see a number of other parties continue to support the use of CEC-approved equipment lists.[194]

In stark contrast to the proposals of the IOUs and TURN, ORA offers a well-designed path to increase consumer protection in cooperation with solar industry efforts. Specifically, ORA proposes to continue to utilize www.gosolarcalifornia.com as an information clearinghouse. The website would include expanded information about renewable distributed generation and the current and future NEM programs, including information about the economics of self-generation, the mechanisms for purchasing renewable generation, consumers' rights when interacting with solar installers and their utility, information about solar industry best practices, and dispute resolution resources.[195] Most importantly, this proposal would increase

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190 *See, e.g.*, SCE Proposal, p. 44.

191 *See, e.g.*, SCE Proposal, p. 44; SDG&E Proposal, Attachment A, pp. A-79 – A-80.

192 *See e.g.*, TURN Proposal, pp. 26-28; SDG&E Proposal, Appendix A, p. A-80.

193 SCE Proposal, p. 44.

194 *See e.g.*, SCE Proposal, p. 44.

195 ORA Proposal, pp. A-31 – A-32.

resources for consumers to help them understand their rights while also respecting the limits of the Commission's jurisdiction over the solar industry.

XII. ALTERNATIVES DESIGNED FOR GROWTH IN DISADVANTAGED COMMUNITIES

The Joint Solar Parties appreciate the utilities' and other parties' proposals of new programs and expanding existing programs for disadvantaged communities. We are encouraged by the clear demonstration of commitment to increasing opportunities for low-income customers to participate in California's clean energy revolution. All the proposals demonstrate an effort by parties to tackle the barriers that have resulted in substantially lower rates of deployment of solar in disadvantaged communities.

A number of proposals recommended the expansion of existing SASH and MASH programs. While we support an expansion of SASH and MASH incentives as part of the solution for disadvantaged communities, we do not consider such an approach a sufficient solution on its own, since only a small slice of customers in disadvantaged communities would be eligible for those incentives and since it is not clear that an ongoing and sufficiently large source of funding can be made available to make these programs fully scalable.

The utilities propose a number of approaches to increasing deployment of solar in disadvantaged communities, including programs where the solar capacity would be solely utility-owned. We submit that a requirement for utility ownership will not provide the best results for ratepayers, particularly at this stage of market maturity.

In the Disadvantaged Communities portion of Vote Solar/SEIA's Aug 3 proposal, we outlined three Guiding Principles for designing effective proposals for these communities, included again for the reader's convenience below. These Guiding Principles are useful to highlight the elements we support – and those with which we are concerned – in the Disadvantaged Communities proposals of the three IOUs, in the two alternatives noted in the Disadvantaged Communities Staff Paper, and in the proposals from TURN and ORA.

<u>Guiding Principles for Designing Effective Alternatives for Disadvantaged Communities</u>

1. *The policy effectively addresses or avoids two or more of the barriers specific to disadvantaged communities listed above.* These include 1) barriers to accessing capital or financing, 2) small or nonexistent tax liability, 3) barriers to education and

marketing, 4) low levels of homeownership and 5) lower rates that reduce bill savings.

2. *Projects facilitated by the policy will be financeable.* For example, under virtual net metering, the geographic footprint of the program must be large enough to identify sufficient customer offtakers, and developers must have sufficient certainty about the contract price they will receive.

3. *The policy is truly scalable, allowing it to facilitate meaningful DG growth in disadvantaged communities on an ongoing basis.* Policies or programs that rely on a temporary pool of incentive funds that are likely to be exhausted over a short period, for example, should be lower priority than policies that make more efficient use of existing, ongoing subsidies or that do not require dedicated funding at all.

A. PG&E

PG&E proposes a program it calls "SolarCARE," in which CARE customers in disadvantaged communities could enroll to have 100% of their annual usage provided by a local solar project, built and operated by a third party developer, sited in a disadvantaged community. Participants would stay on their CARE rate. Additional premiums to cover the cost of solar generation would be subsidized through other non-CARE customers or through outside funding, such as general ratepayer rate increases or Greenhouse Gas Reduction Fund (GGRF) funding, in order to ensure that the CARE customer's rates remain the same.[196] PG&E proposes a program size of 28 MW over the next three years, and proposes that the utility would be the program administrator.

We commend PG&E for proposing a new approach that would expand access to shared solar for CARE customers. We view PG&E's proposal as aligning reasonably well with our first Guiding Principle. Solar CARE would address or avoid several of the barriers specific to these communities (namely, barriers to accessing capital or financing, small or nonexistent tax liability, and low levels of homeownership, although it seems that barriers to education and marketing and the barrier of lower rates and reduced bill savings would still remain.)

While PG&E's proposed program could potentially meet Guiding Principle 2, focused

[196] Enabling legislation included AB 32 (2006) and SB 1018 (2012), which the Commission implemented in Decision12-12-033.

on ensuring projects will be financeable, more information is needed about the geographic limitations of the program. While PG&E's proposal would cover the premium for CARE customers through ratepayer or GHG funding, it is unclear whether the shared solar program PG&E is proposing would be designed in a way that would attract market participants. PG&E proposes to "determine a preliminary set of locations within disadvantaged communities that would be ideal for siting the community solar systems" and "solicit input from members of these local communities… for the best places to site such systems."[197] PG&E notes that participants would "support renewables in their community" but does not make clear what limitations would be apply as the definition of "their community." As VS/SEIA noted in our August 3 proposals, geographic flexibility is necessary to ensure that developers can build well-sited and cost-effective VNEM projects in disadvantaged communities. We recommend that there be no geographic restriction beyond the projects and participants both being located in a designated disadvantaged community within the same utility service territory.

Since PG&E's proposal will require additional funding, it is unlikely to be truly scalable, as our Guiding Principle 3 requires. As PG&E notes, "Customers would continue to take service on their regular CARE rate and would not pay any additional premium for this service… Any cost in excess of the revenue from participants would be funded through other non-CARE customers or through outside funding, such as through Greenhouse Gas Reduction Fund (GGRF) funding… Using the 28 MW program cap, PG&E estimates the range of first year program subsidy to be from a low of $500,000 to $2,500,000." [198] AB 327's statutory requirement to develop alternatives for disadvantaged communities offers a powerful opportunity for the Commission to approve policies that will create meaningful and permanent new paths to allow hard-to-reach customers to gain access to the benefits of clean DG. While the growth targets for disadvantaged communities have not yet been set in this proceeding, PG&E's proposed 28 MW program is too limited in size to fully address this opportunity on its own. Even if the first round of funding is approved, additional funding may not follow or may come only sporadically, thereby creating a stop-start program that suffers from inefficiencies and does not grow organically as customer demand grows. By comparison, CleanCARE would make more efficient

[197] PG&E Proposal, pp. 60-61.

[198] *Id.*, p. 62.

use of already-allocated CARE funding and could be scaled up as demand grows, and Disadvantaged Communities VNEM would leverage private capital instead of ratepayer or taxpayer funding; both options avoid the need to secure additional funding over the long-term.

In addition, PG&E's proposal would be available only to CARE customers. As many parties proposed in their August 3 proposals, disadvantaged communities should be defined in this proceeding as including both socioeconomic and environmental pollution factors. Non-CARE customers in Disadvantaged Communities should also have new opportunities to access clean DG, which would require additional alternatives beyond any proposal that is limited only to CARE customers.

Finally, we have concerns with PG&E's proposal to be the administrator of SolarCARE. Barriers to education and marketing for these customers exist, and utilities may not be properly motivated to overcome these barriers in order to facilitate the growth of clean DG that will not be part of their rate-based infrastructure. We propose that a third-party program administrator with experience outreaching to these communities may be a more effective choice for administering programs in disadvantaged communities.

B. SDG&E

SDG&E proposes two program elements for disadvantaged communities: the Multi-Family Solar Share program and the Solar At Schools program. SDG&E is the only utility that proposes an exclusively utility-owned approach for disadvantaged communities; SDG&E would install and own all of the solar arrays, which would be sited on customer-owned buildings located in Disadvantaged Communities. Participants of either program would receive bill credits at the system average commodity rate, rather than the full retail rate.

We strongly disagree with SDG&E that participants will be best served by a solely utility-owned program. When suppliers compete to serve a market, costs are driven down and suppliers innovate to provide the greatest value for customers. The Commission's California Solar Statistics website, for example, shows that the competitive solar market in California has driven average installed costs down by half from 2009 to 2014.[199] By contrast, when a utility installs and owns solar that will be added to its rate base and paid for by its non-participating

[199] See https://www.californiasolarstatistics.ca.gov/

customers, the utility faces no competition from other suppliers and it has little incentive to keep costs as low as possible. As past experience with other IOU-led PV programs demonstrates, sole-source, utility-owned solar programs have not proved to be cost-effective in comparison to competitively bid programs. We urge the Commission to reject SDG&E's proposal outright and require alternatives for disadvantaged communities that promote competition and innovation.

C. SCE

SCE proposes a more complex set of disadvantaged communities proposals than the other two utilities. The proposal includes four elements, listed below. To fund the incentives and marketing-related activities for SCE's proposal for disadvantaged communities, SCE requests that the Commission authorize it to use 15% of its net greenhouse gas (GHG) Cap-and-Trade program revenues.

1) Enhanced up-front incentives to install solar PV systems for low-income customers living in single or multi-family residences in disadvantaged communities. SCE proposes creating new incentive programs that are structured like SASH and MASH, but available only to customers who own low income homes, either single-family or in multi-family residences; the programs would be administered by the current SASH and MASH administrators (GRID Alternatives for SASH, and PG&E, SCE and the Center for Sustainable Energy in SDG&E territory for MASH.)
2) Bill credits for any individually metered customers in multi-family residences in disadvantaged communities equal to the utility's proposed Export Compensation Rate of $0.08 c/kWh.
3) Targeted marketing, education and outreach in disadvantaged communities regarding SCE's renewable programs, and
4) Expanded community solar in disadvantaged communities, either through PPAs with third party developers (with any premium payment for participants subsidized with available funding) or through utility-owned community solar systems built by third parties.

SCE's proposal to create a MASH and SASH specifically for customers in disadvantaged communities does address barriers to accessing capital and financing, and avoids the issue of small or nonexistent tax liability. We agree that expanding solar incentives for low-income homeowners is a positive step for expanding solar access in disadvantaged communities. However, we do not see increased SASH and MASH-like incentives as adequate solutions on their own, for two reasons. First, a major failure of this approach is that it does not address the barrier of low levels of homeownership in disadvantaged communities, because SASH and MASH-style incentives are only available to customers who own roofs that are properly oriented and otherwise suitable for solar. Renters, for example, comprise 66% of disadvantaged communities, as noted in the Disadvantaged Communities Staff Paper. Fairness requires that they, and homeowners with roofs not suitable for solar, also be provided with viable new alternatives via this proceeding.

A second issue with increasing incentives for SASH and MASH relates to our Guiding Principle #3 on scalability. The SCE proposal is not a truly scalable option if it relies on limited funding that will be quickly exhausted as demand grows. The history of SASH and MASH funding provides a stark recent example; as SCE notes, AB 217 authorized additional funding for both programs in 2013, and SCE expects that this additional MASH funding in its service territory will already be exhausted by early 2016.[200] SCE attempts to solve this problem by proposing that its new incentives be funded on an ongoing basis with 15% of the annual net GHG Cap-and-Trade program revenue that SCE was authorized to collect in D.12-12-033. However, some of these incentives should be administered by non-utility entities like GRID Alternatives and CSE, and it appears that this would not be an allowable use of such funds, since SCE notes that D.12-12-033 requires that eligible programs must be administered by the utility.[201] Without an ongoing allocated source of funding, incentives are likely to serve only a tiny percentage of customers in disadvantaged communities before being exhausted, and are therefore not a fully scalable solution on their own.

In addition, SCE’s proposed ECR rate of $0.08 cents/kWh would greatly undercompensate participating customers for the benefits of their clean solar generation, as discussed in Section V regarding the broader successor tariff proposals above. Instead, the Commission should expand VNEM as proposed in our Disadvantaged Communities VNEM proposal, providing a full retail rate credit for customers in those communities who sign up for

200 SCE Proposal, p. 56.

201 *Id.*, p. 57.

VNEM.

D. ORA

In contrast to SCE's more complex proposal, ORA's proposal for disadvantaged communities is narrow: ORA notes that the Commission directed GRID Alternatives to submit a proposal for a third party ownership (TPO) model for SASH in D.15-01-027, and approved that advice letter in June of this year. ORA proposes that the Commission wait for data on the success of this program and consider increasing SASH incentives for that program if it is successful.

We agree with ORA that a successful TPO model for SASH will need to allow customers in disadvantaged communities to access solar by overcoming the barrier of upfront costs. ORA's proposal aligns with Guiding Principle 1 by overcoming barriers to accessing capital or financing, and small or nonexistent tax liability. The TPO model also addresses Guiding Principle 2 by providing a program that enables projects to be financeable, since the program administrator will prepay the PPA payments on behalf of customers.

However, ORA's proposal on its own is even less scalable than SCE's disadvantaged communities proposal. The goal in implementing Section 2827.1(b)(1) should be to create policy alternatives that meaningfully expand access to clean DG in disadvantaged communities on an ongoing basis, but expanding the SASH TPO program would expand access to only a narrow set of those customers: those who own single-family low income housing and have roofs suitable for solar. Many customers in disadvantaged communities would be left out of this plan – renters, occupants of multi-family housing of all kinds, homeowners who do not qualify as SASH-eligible, and SASH-eligible homeowners whose roofs are not suitable for solar. In addition, ORA does not propose an ongoing source of funding for expanding SASH TPO incentives. And as noted above, without an ongoing allocated source of funding, SASH TPO incentives are likely to serve only a tiny percentage of customers in disadvantaged communities before being exhausted, and thus do not provide a scalable solution on their own.

E. TURN

TURN's proposal for disadvantaged communities is similar to its NEM successor tariff proposal, with the addition of upfront financial incentives to help customers finance their own solar installation. Under TURN's proposal, once a customer in a disadvantaged community leverages the upfront incentives to install solar, they will be eligible for the same VODE and DGA as will be used for other NEM customers. TURN's recommendation to leverage GGRF or ratepayer dollars to expand the SASH and MASH program is in line with a number of other proposals for disadvantaged communities in this proceeding and we support such a proposal, particularly if ongoing funding is made available rather than a one-time allocation that will be quickly exhausted. However, as we note elsewhere in this section, expansion of upfront incentives in the form of SASH and MASH should not be the only program leveraged to address the challenges of deploying solar in disadvantaged communities, as it does not fully address the various barriers to deployment in these communities.

TURN's proposal aligns reasonably well with Guiding Principle 1 by overcoming at least two of the barriers to deployment specific to disadvantaged communities. As TURN notes in its comments, the proposal addresses financial barriers by providing upfront incentives. However, in leveraging the SASH and MASH program, this proposal does not address the issue of low levels of homeownership, which is a significant barrier in low-income communities.

It is also not clear if TURN's proposal meets the second guiding principle of financeability. While we know that the SASH and MASH program, when coupled with the existing NEM tariff, have been successful programs, it is not at all clear that the same upfront incentives will be appealing to customers with a different tariff proposal.

Last, unless funding is made on an ongoing basis, TURN's proposal falls short of Guiding Principle 3 regarding scalability. SASH and MASH incentives would need to subsidize the entire upfront system cost of installing solar in low-income communities, since many customers in these communities can only participate if the system is cash flow positive from the first day. Therefore, it may be difficult to allocate sufficient ongoing funds to support meaningful growth in these communities via increased SASH and MASH incentives alone.

F. Staff Proposal: Neighborhood VNEM

We are very encouraged by the Staff proposal for a Neighborhood Virtual Net Metering program, as we believe that it both addresses the main barriers to solar adoption for disadvantaged communities, and proposes a remedy that can work. The Staff Disadvantaged Communities Paper appropriately identifies the Massachusetts Virtual Net Metering program as a model in many ways for developing California's disadvantaged communities NEM tariff. As

Vote Solar/SEIA noted in their August 3 Disadvantaged Communities tariff proposal, an expanded VNEM program could be an effective program design to address the main obstacles preventing significant deployment of solar in low-income communities, leveraging private capital to expand access to clean DG in disadvantaged communities in a financeable and scalable way.

Staff's Neighborhood VNEM proposal aligns well with Guiding Principle 1, since it addresses or avoids at least four of the barriers specific to these communities. First, since participants are able to receive credit from an offsite DG project, low levels of homeownership in disadvantaged communities will not reduce participation. Second, since participants would not have to own the system but could rather participate in a PPA agreement with a developer, low tax liability will not prevent participation, and the need to access capital or financing is avoided. Staff's Neighborhood VNEM program also addresses barriers to accessing capital or financing. Barriers to education and marketing would also be overcome because developers are incented to target these communities in order to secure customers.

Vote Solar/SEIA recommended several amendments to Staff's VNEM program design as necessary to ensure that the program is effective in its goal of deploying solar in disadvantaged communities. First, in order to address the barrier of low discounted bill savings, Vote Solar/SEIA proposed adding a VNEM credit multiplier that would apply to CARE customers.

Second, in order to align with our second Guiding Principle of ensuring financeable projects, we proposed expanding the eligible geographic area for projects and participants from the same census tract to any disadvantaged community within the same IOU service territory. A census tract is smaller than a zip code and includes an average of only 4000 residents; this is not a large enough eligible area to ensure that both developers and customers have the flexibility they need to make the program viable and financeable. So long as developers are able to access a wide pool of potential customers and replace them if the customer moves outside a disadvantaged community or defaults on its PPA, the risks to developing projects for lower-income communities will not deter investments.

Third, in order to improve scalability, Vote Solar/SEIA proposed to remove the requirement that VNEM projects in disadvantaged communities be sized based on customer commitments, since participants should be able to sign up throughout the development process, not just before. Since the host customer and not the utility will be assigned any unsubscribed

NEM credits, projects developers will already be incentivized to size their projects appropriately. And finally, also to facilitate scalability, Vote Solar/SEIA proposed to allow the host customer to have only parasitic load for the project to qualify for the program, consistent with the Massachusetts VNEM program rules. This clarification of Staff's proposal would expand the pool of available project types to ground-mounted projects and others not co-located with a significant load, driving down overall costs.

G. Staff Proposal: SASH AND MASH Expansion

Staff's alternative proposal was to expand funding under the SASH and MASH programs. These programs have been successful at increasing deployment of solar for some segments of disadvantaged communities and we support the expansion of funding for these programs. However, as discussed above, we believe expansion of these programs must be accompanied by other policies in order to sufficiently meet the intent of Section 2827.1(b)(1).

XIII. CONCLUSION

The Joint Solar Parties appreciate the opportunity to file these comments addressing party proposals.

Respectfully submitted this September 1, 2015 at San Francisco, California.

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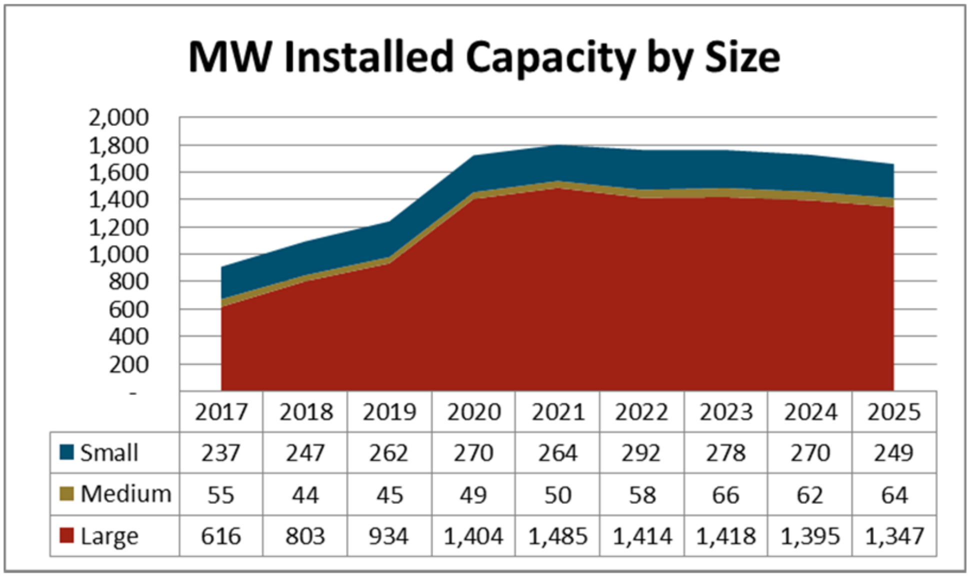
202 In accordance *with* Commission Rule 1.8(d), counsel for the Solar Energy Industries Association is authorized to sign these comments on behalf of the members of the Joint Solar Parties.

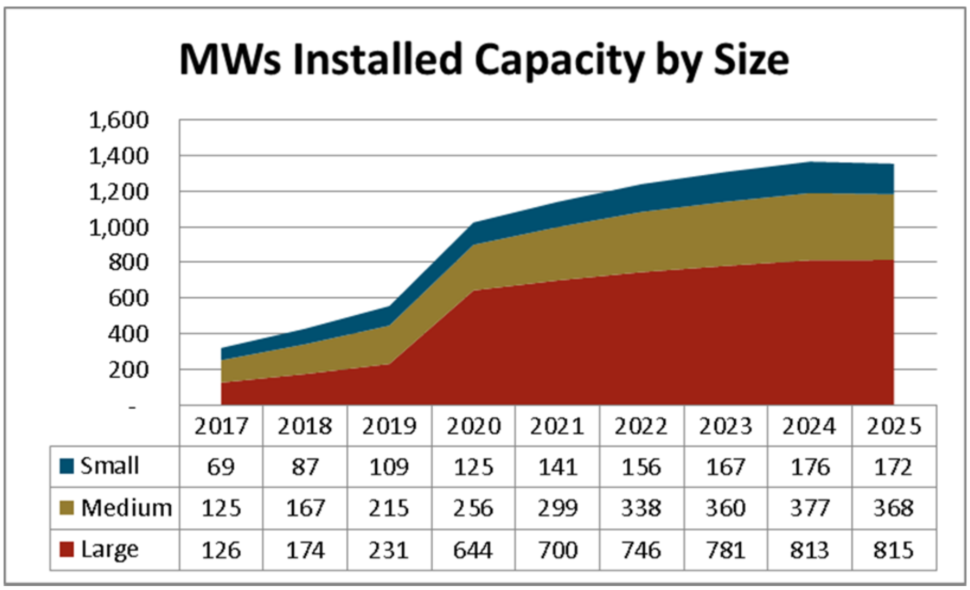
Appendix A: Comparison of System Size Mix in Party Proposals With and Without System Sizing Correction

Figure A-1. System Size Results of PG&E Proposal Without Sizing Correction[203]



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	237	247	262	270	264	292	278	270	249
Medium	55	44	45	49	50	58	66	62	64
Large	616	803	934	1,404	1,485	1,414	1,418	1,395	1,347

Figure A-2. System Size Results of PG&E Proposal With Sizing Correction[204]

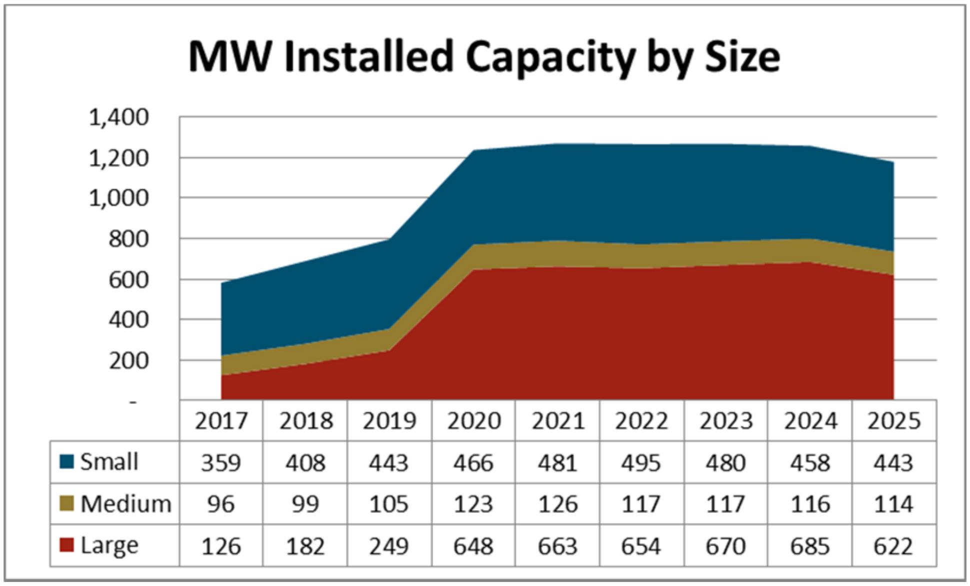


	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	69	87	109	125	141	156	167	176	172
Medium	125	167	215	256	299	338	360	377	368
Large	126	174	231	644	700	746	781	813	815

203 Using PG&E Third Case with Tiered Rates.

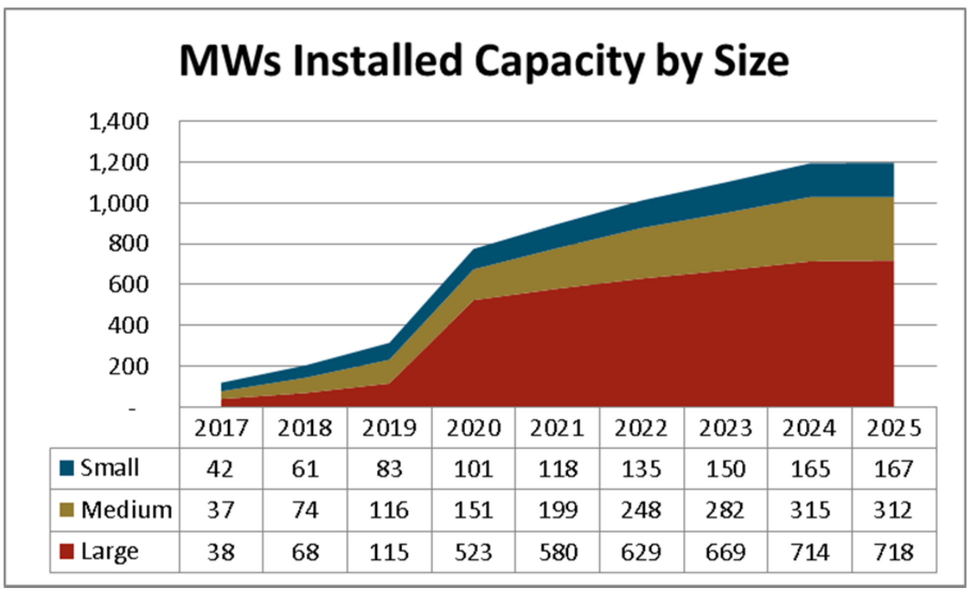
204 Each of the charts with the sizing correction uses the JSP Inputs with tiered rates.

Figure A-3. System Size Results of SCE Proposal Without Sizing Correction[205]



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	359	408	443	466	481	495	480	458	443
Medium	96	99	105	123	126	117	117	116	114
Large	126	182	249	648	663	654	670	685	622

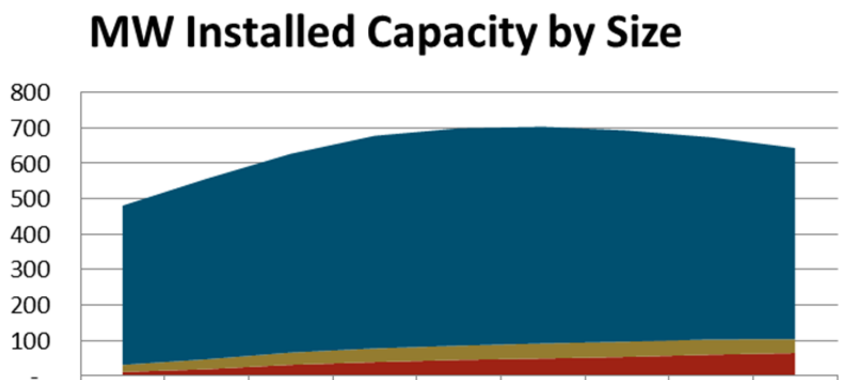
Figure A-4. System Size Results of SCE Proposal With Sizing Correction



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	42	61	83	101	118	135	150	165	167
Medium	37	74	116	151	199	248	282	315	312
Large	38	68	115	523	580	629	669	714	718

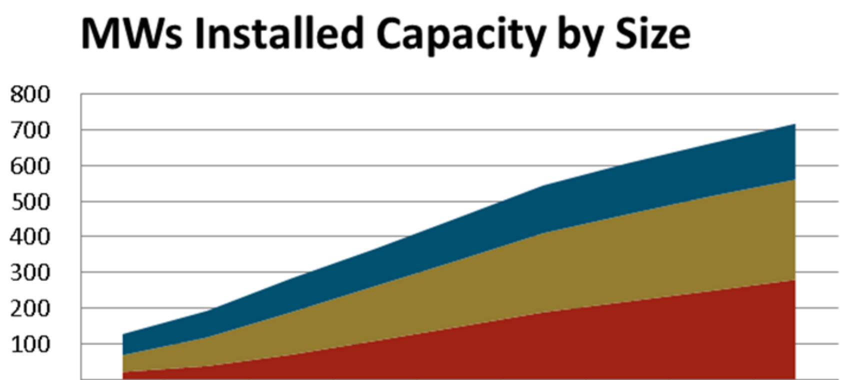
205 Using SCE Third Case with Tiered Rates.

Figure A-5. System Size Results of SDG&E Default Without Sizing Correction[206]



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	449	509	561	600	613	611	596	570	539
Medium	20	28	34	38	40	43	43	43	39
Large	12	20	32	40	46	50	54	61	65

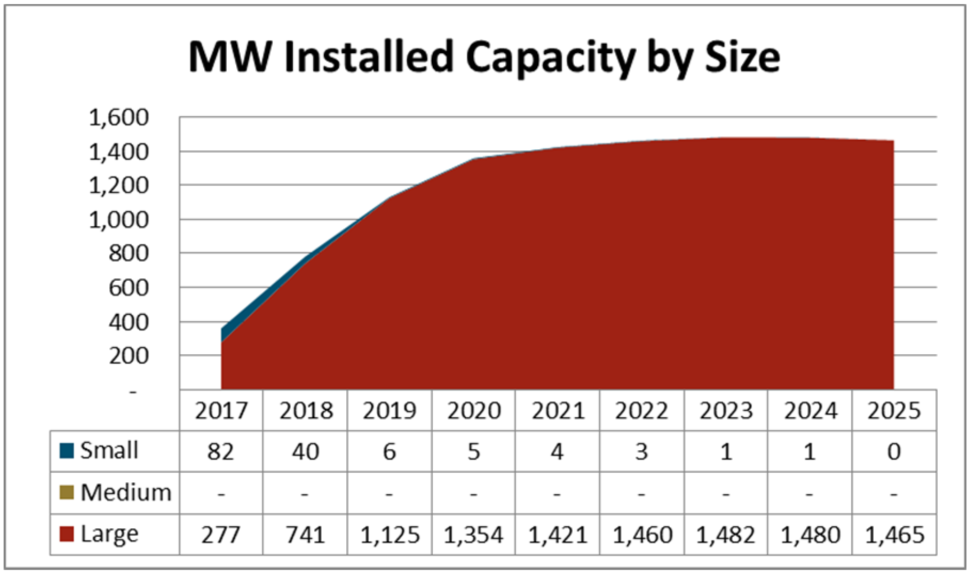
Figure A-6. System Size Results of SDG&E Default With Sizing Correction



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	59	74	95	105	120	134	143	148	157
Medium	47	80	119	153	187	222	244	265	281
Large	21	37	69	108	148	189	219	249	280

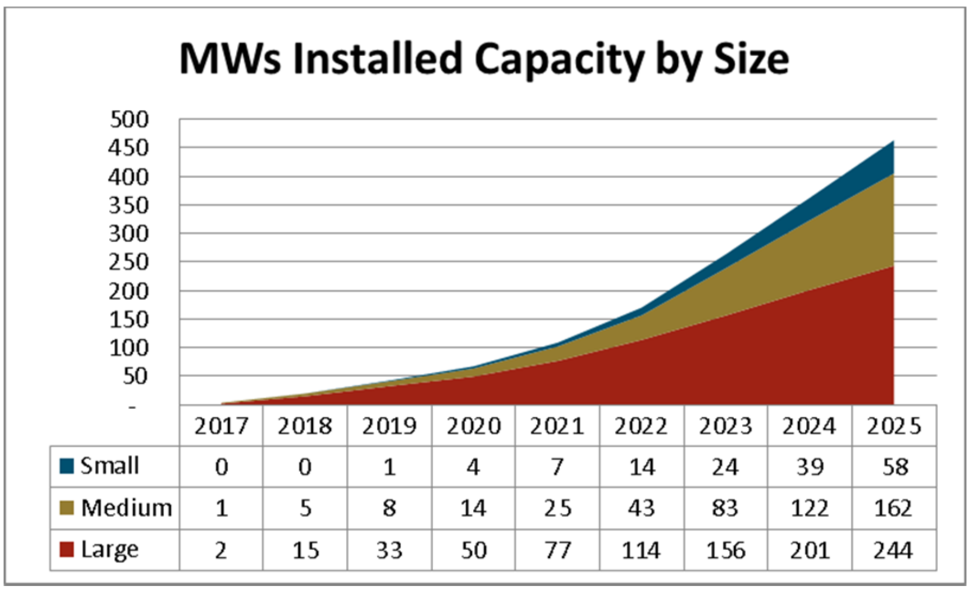
206 Using High DG Value bookend.

Figure A-7. System Size Results of SDG&E Default Without Sizing Correction



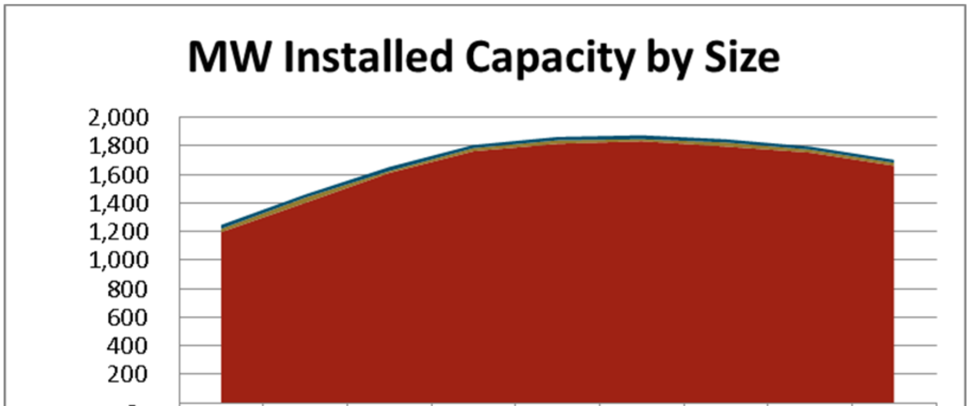
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	82	40	6	5	4	3	1	1	0
Medium	-	-	-	-	-	-	-	-	-
Large	277	741	1,125	1,354	1,421	1,460	1,482	1,480	1,465

Figure A-8. System Size Results of SDG&E Default With Sizing Correction



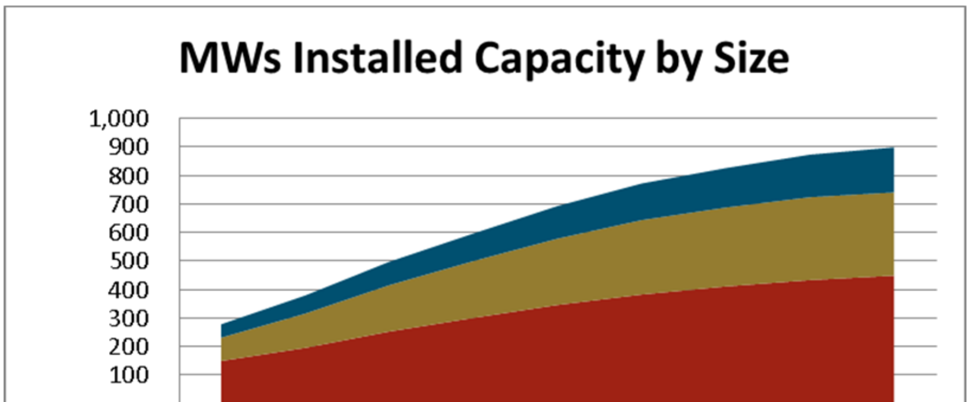
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	0	0	1	4	7	14	24	39	58
Medium	1	5	8	14	25	43	83	122	162
Large	2	15	33	50	77	114	156	201	244

Figure A-9. System Size Results of ORA $10 ICF Proposal Without Sizing Correction[207]



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	28	22	29	22	24	28	23	22	22
Medium	23	36	13	22	24	14	28	20	20
Large	1,197	1,402	1,612	1,764	1,816	1,834	1,797	1,754	1,662

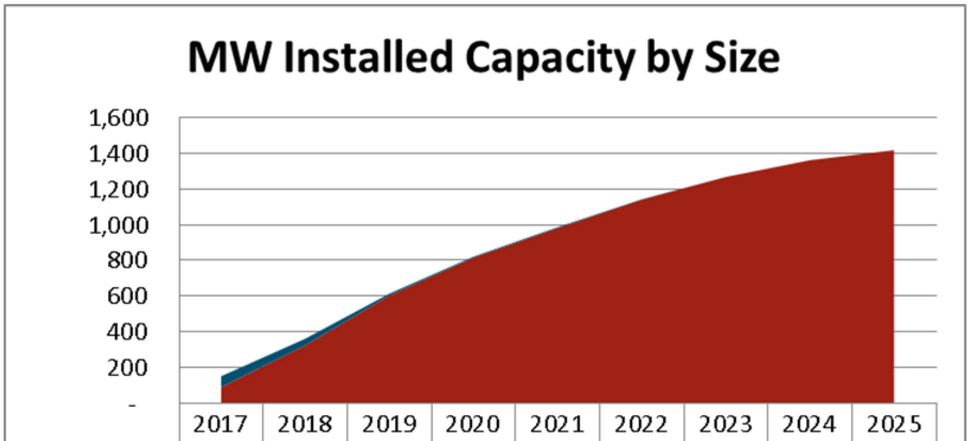
Figure A-10. System Size Results of ORA $10 ICF Proposal With Sizing Correction



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	47	64	82	97	115	129	138	149	158
Medium	82	120	163	199	232	261	277	291	292
Large	150	196	253	301	346	383	411	434	449

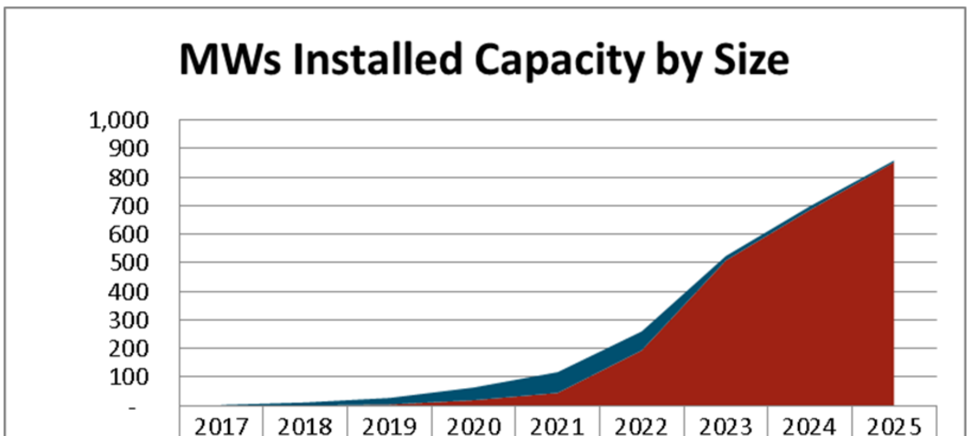
207 High Value DG 2-Tier case.

Figure A-11. System Size Results of TURN Proposal With $0.06 Adder Without Sizing Correction[208]



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	60	37	10	5	4	2	0	0	0
Medium	0	0	0	0	0	0	0	0	0
Large	90	323	603	816	982	1,141	1,268	1,362	1,418

Figure A-12. System Size Results of TURN Proposal With $0.06 Adder With Sizing Correction



	2017	2018	2019	2020	2021	2022	2023	2024	2025
Small	3	11	23	45	73	67	16	13	6
Medium	-	0	0	-	-	-	-	-	-
Large	0	0	4	19	45	194	509	686	853

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208 Base DG Costs Case.

Appendix B. Analysis of Simple Payback for U.S. DOE Typical Residential Customer

As described in Section IV.B.4, analysis of the capital recovery period for a typical customer demonstrates that the Public Tool's "implied payback period" methodology produces results that are far shorter than what is commonly known as the payback period. Simple payback periods under the IOUs' successor tariff proposals can modeled in a straightforward and transparent manner, and are vastly different form the implied payback periods in the Public Tool.

The U.S. Department of Energy (U.S. DOE) maintains a database for study purposes of hourly load profiles that are calibrated to the typical meteorological year. The profiles are derived from the Residential Energy Consumption Survey, now in its thirteenth iteration, which is designed to determine average electricity usage characteristics separated into high, base, and low usage categories.[209] For this analysis, a base residential customer in Fresno was chosen, simply because Fresno is a well-known city in a sunny part of the state.[210] Consumption totals are summarized in Table B-1 according to TOU periods proposed by PG&E in A.14-11-014 and by SDG&E in A.14-01-027.

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209 U.S. DOE, Office of Energy Efficiency and Renewable Energy, "Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States," available at http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states/resource/b341f6c6-ab5a-4976-bd07-adc68a2239c4.

210 The load profile is available at http://en.openei.org/datasets/files/961/pub/RESIDENTIAL_LOAD_DATA_E_PLUS_OUTPUT/BASE/USA_CA_Fresno.Air.Terminal.723890_TMY3_BASE.csv.

Table B-1. Consumption Profile of U.S. DOE Typical Residential Customer in Fresno

		PGE		SCE	SDGE		
Month	Total	On Peak	Off Peak	Non-TOU	On-Peak	Semi-Peak	Off-Peak
Jan	754	241	513	754	207	432	115
Feb	646	202	444	646	174	371	101
Mar	643	198	445	643	171	371	101
Apr	602	194	408	602	161	348	93
May	771	274	497	771	219	456	96
Jun	960	357	602	960	483	384	93
Jul	1,272	459	813	1,272	625	520	127
Aug	1,144	423	721	1,144	574	456	113
Sep	961	348	614	961	469	394	98
Oct	840	301	539	840	241	505	94
Nov	647	217	430	647	185	369	92
Dec	745	242	502	745	207	424	114
Total	9,984	3,455	6,529	9,984	3,717	5,030	1,238

Using assumptions that the roof has 5% shading and is oriented at 210 degrees (south-southwest), a 4.6 kW-DC system would be needed to offset two-thirds of the customer's usage. Entering those assumptions with a Fresno location in NREL's PV Watts tool produces hourly production estimates for the system. Those 8760 data points are summarized in Table B-2.

Table B-2. Production Profile of 4.6 kW Solar System in Fresno

		PGE		SCE	SDGE		
Month	Total	On Peak	Off Peak	Non-TOU	On-Peak	Semi-Peak	Off-Peak
Jan	285	13	272	285	2	283	
Feb	386	26	359	386	6	380	
Mar	568	46	522	568	14	554	
Apr	674	67	607	674	25	649	1
May	754	84	670	754	35	716	3
Jun	748	91	657	748	241	504	3
Jul	766	98	668	766	255	509	2
Aug	724	81	642	724	234	489	1
Sep	607	46	562	607	167	441	
Oct	530	24	506	530	4	526	
Nov	375	10	366	375	1	374	
Dec	263	7	256	263	1	262	
Total	6,680	591	6,089	6,680	982	5,687	11

Matching consumption against production for each hour of the year results in a determination of the portion of solar electricity production that is consumed on-site and the portion that is exported to the grid. The amounts of electricity that would be exported to the grid by this customer are summarized in Table B-3.

Table B-3. Exports to the Grid for Typical Solar Customer

		PGE		SCE	SDGE		
Month	Total	On Peak	Off Peak	Non-TOU	On-Peak	Semi-Peak	Off-Peak
Jan	(90)		(90)	(90)		(90)	
Feb	(184)	(2)	(182)	(184)		(184)	
Mar	(332)	(9)	(323)	(332)		(332)	
Apr	(411)	(12)	(399)	(411)		(411)	
May	(392)	(7)	(384)	(392)		(392)	
Jun	(286)	(1)	(285)	(286)	(33)	(253)	
Jul	(187)		(187)	(187)	(11)	(175)	
Aug	(220)		(219)	(220)	(17)	(202)	
Sep	(215)		(215)	(215)	(19)	(196)	
Oct	(216)		(216)	(216)		(216)	
Nov	(183)		(183)	(183)		(183)	
Dec	(82)		(82)	(82)		(82)	
Total	(2,796)	(31)	(2,766)	(2,796)	(81)	(2,715)	0

Determining the bill savings from solar requires calculating the pre-solar bill and the post-solar bill. The pre-solar bill is simply a matter of applying rates to the usage totals. In order to take the differences between IOU rates out of the picture, this analysis uses PG&E rates,[211] which are higher than SCE's rates and lower than SDG&E's rates.

211 The specific rates used are PG&E's rates after the restructuring ordered by D.15-07-001 is complete, as reported in "Supplemental Information of Pacific Gas and Electric Company Pursuant to July 23, 2015, Administrative Law Judge's Email Ruling," July 9, 2015: 18.432 c/kWh for usage up to baseline and 23.244 c/kWh for usage above baseline.

Table B-4. Pre-Solar Bill for Typical Solar Customer

Month	Usage (kWh)	Bill
Jan	754	$158.73
Feb	646	$135.15
Mar	643	$133.00
Apr	602	$123.80
May	771	$162.72
Jun	960	$202.97
Jul	1,272	$274.92
Aug	1,144	$245.16
Sep	961	$203.37
Oct	840	$178.73
Nov	647	$134.31
Dec	745	$156.51
Total	9,985	$2,109.38

The post-solar bill is then calculated by applying rates to the portion of usage that is not simultaneously offset by solar, then subtracting the compensation for exported power. The post-solar bills for each of the IOU successor tariff proposals are shown in Tables B-5 - B-7.

For simplicity of analysis, the bill savings under PG&E's proposal uses the blended compensation rate of 9.2 c/kWh rather than the time-dependent compensation rates in the actual proposal. Because almost none of the exported power occurs during PG&E's proposed new peak period of 4:00-9:00 pm, this may be an overly generous assumption. Also note that this load profile has a high load factor, i.e. it is not very "peaky" and would not incur high demand charges. The mean peak annual demand for PG&E residential customers is 4.87 kW,[212] and the US. DOE Fresno profile peaks at 4.05 kW (without solar). For these reasons, the payback period for PG&E is likely to be significantly understated.

[212] PG&E response to data request number CalSEIA_006-01-08, Question 1, August 26, 2015.

Table B-5. Post-Solar Bill After Solar Investment Under PG&E Proposal

	Compensation		Charges					
			Usage from Grid (kWh)					
Month	Exports	Export Comp	On Peak	Part Peak	Off Peak	Demand	Energy	Total
Jan	90	$8.26		170	299	$6.00	$92.78	$90.52
Feb	184	$16.92		123	137	$6.00	$72.94	$62.02
Mar	332	$30.56		102	(27)	$6.00	$65.92	$41.35
Apr	411	$37.83		92	(164)	$6.00	$54.44	$22.61
May	392	$36.04		143	(125)	$9.00	$66.86	$39.82
Jun	286	$26.32	187		25	$9.00	$123.41	$106.09
Jul	187	$17.18	271		235	$9.00	$173.90	$165.71
Aug	220	$20.24	229		192	$9.00	$158.21	$146.97
Sep	215	$19.74	218		136	$9.00	$142.01	$131.27
Oct	216	$19.84		208	103	$9.00	$87.56	$76.72
Nov	183	$16.84		139	132	$6.00	$74.82	$63.98
Dec	82	$7.52		174	307	$6.00	$93.54	$92.02
Total	2,797	$257.30	905	1,151	1,250	$90.00	$1,206.38	$1,039.08

Table B-6. Post-Solar Bill from Solar Investment Under SCE Proposal

	Compensation		Charges			
Month	Exports	Export Comp	Usage (kWh)	Fixed	Energy	Total
Jan	90	$7.19	559	$14.74	$104.80	$112.35
Feb	184	$14.71	444	$14.74	$80.81	$80.83
Mar	332	$26.58	407	$14.74	$72.48	$60.64
Apr	411	$32.90	339	$14.74	$60.29	$42.13
May	392	$31.34	410	$14.74	$72.90	$56.30
Jun	286	$22.88	498	$14.74	$89.93	$81.78
Jul	187	$14.94	693	$14.74	$133.65	$133.45
Aug	220	$17.60	640	$14.74	$121.57	$118.71
Sep	215	$17.17	568	$14.74	$106.06	$103.63
Oct	216	$17.25	526	$14.74	$97.28	$94.76
Nov	183	$14.64	454	$14.74	$81.68	$81.78
Dec	82	$6.54	563	$14.74	$105.79	$113.99
Total	2,797	$223.74	6,101	$176.88	$1,127.23	$1,080.37

Table B-7. Post-Solar Bill after Solar Investment Under SDG&E Proposal

	Compensation		Usage from Grid (kWh)			Charges			
Month	Exports	Export Comp	On-Peak	Semi-Peak	Off-Peak	Fixed	Demand	Energy	Total
Jan	90	$3.60	153	291	115	$20.54	$18.38	$63.47	$98.79
Feb	184	$7.36	120	223	101	$20.54	$18.38	$50.30	$81.86
Mar	332	$13.28	106	199	101	$20.54	$18.38	$45.84	$71.48
Apr	411	$16.44	100	147	91	$20.54	$18.38	$38.29	$60.77
May	392	$15.68	151	166	93	$20.54	$27.57	$81.49	$113.92
Jun	286	$11.44	192	215	90	$20.54	$27.57	$101.29	$137.96
Jul	187	$7.48	288	280	125	$20.54	$27.57	$145.38	$186.01
Aug	219	$8.76	239	288	112	$20.54	$27.57	$128.73	$168.08
Sep	215	$8.60	232	239	98	$20.54	$27.57	$118.61	$158.12
Oct	216	$8.64	222	211	93	$20.54	$27.57	$111.10	$150.57
Nov	183	$7.32	123	239	92	$20.54	$18.38	$51.53	$83.13
Dec	82	$3.28	153	297	114	$20.54	$18.38	$64.03	$99.67
Total	2,797	$111.88	2,079	2,795	1,225	$246.48	$275.70	$1,000.08	$1,410.38

The cost of solar was determined according to the base solar cost in the Public Tool for 2017 ($3.44/W-DC). For determining the payback period, the first year bill savings was escalated each year at 2.5%, representing a 3% rate escalation less 0.5% panel degradation. The resulting cumulative cash flows shown in the following tables equate to payback periods of 13.0 years for PG&E, 13.3 years for SCE, and 20.7 years for SDG&E.

Table B-8. Cash Flow for Solar Investment Under PG&E Proposal and Rates

Year	Project Cost	Application Fee	O&M	Electric Bill Savings	Cash Flow	Cumulative Cash Flow
	($15,824)	($100)			($15,924)	($15,924)
1			$0	$1,056	$1,056	($14,868)
2			$0	$1,082	$1,082	($13,786)
3			$0	$1,109	$1,109	($12,676)
4			$0	$1,137	$1,137	($11,539)
5			$0	$1,166	$1,166	($10,373)
6			$0	$1,195	$1,195	($9,179)
7			$0	$1,225	$1,225	($7,954)
8			$0	$1,255	$1,255	($6,699)
9			$0	$1,287	$1,287	($5,412)
10			$0	$1,319	$1,319	($4,093)
11			($32)	$1,352	$1,320	($2,773)
12			($32)	$1,386	$1,354	($1,420)
13			($32)	$1,420	$1,388	($32)
14			($32)	$1,456	$1,424	$1,392
15			($2,272)	$1,492	($780)	$612
16			($32)	$1,529	$1,497	$2,110
17			($32)	$1,568	$1,536	$3,645
18			($32)	$1,607	$1,575	$5,220
19			($32)	$1,647	$1,615	$6,835
20			($32)	$1,688	$1,656	$8,491

Table B-9. Cash Flow for Solar Investment Under SCE Proposal and Rates

Year	Project Cost	Application Fee	O&M	Electric Bill Savings	Cash Flow	Cumulative Cash Flow
	($15,824)	($75)			($15,899)	($15,899)
1			$0	$1,029	$1,029	($14,870)
2			$0	$1,055	$1,055	($13,815)
3			$0	$1,081	$1,081	($12,734)
4			$0	$1,108	$1,108	($11,626)
5			$0	$1,136	$1,136	($10,490)
6			$0	$1,164	$1,164	($9,326)
7			$0	$1,193	$1,193	($8,133)
8			$0	$1,223	$1,223	($6,910)
9			$0	$1,254	$1,254	($5,656)
10			$0	$1,285	$1,285	($4,371)
11			($32)	$1,317	$1,285	($3,086)
12			($32)	$1,350	$1,318	($1,767)
13			($32)	$1,384	$1,352	($415)
14			($32)	$1,418	$1,386	$971
15			($2,272)	$1,454	($818)	$153
16			($32)	$1,490	$1,458	$1,611
17			($32)	$1,528	$1,496	$3,107
18			($32)	$1,566	$1,534	$4,641
19			($32)	$1,605	$1,573	$6,213
20			($32)	$1,645	$1,613	$7,826

Table B-10. Cash Flow for Solar Investment Under SDG&E Proposal

Year	Project Cost	Application Fee	O&M	Electric Bill Savings	Cash Flow	Cumulative Cash Flow
	($15,824)	($280)			($16,104)	($16,104)
1			$0	$699	$699	($15,405)
2			$0	$716	$716	($14,689)
3			$0	$734	$734	($13,954)
4			$0	$753	$753	($13,201)
5			$0	$772	$772	($12,430)
6			$0	$791	$791	($11,639)
7			$0	$811	$811	($10,828)
8			$0	$831	$831	($9,997)
9			$0	$852	$852	($9,146)
10			$0	$873	$873	($8,273)
11			($32)	$895	$863	($7,410)
12			($32)	$917	$885	($6,525)
13			($32)	$940	$908	($5,617)
14			($32)	$964	$932	($4,685)
15			($2,272)	$988	($1,284)	($5,970)
16			($32)	$1,012	$980	($4,989)
17			($32)	$1,038	$1,006	($3,984)
18			($32)	$1,064	$1,032	($2,952)
19			($32)	$1,090	$1,058	($1,894)
20			($32)	$1,117	$1,085	($808)

For ORA, the bill savings from continuing NEM was calculated, then a fixed charge equivalent to the $10 ICF was added ($552 per year for a 4.6 kW system). The result is a payback period of 13.4 years, as shown in the cash flow in Table B-11.

Table B-11. Cash Flow for Solar Investment Under ORA Proposal

Year	Project Cost	O&M	Bill Savings Without Fee	Installed Capacity Fee	Bill Savings With Fee	Cash Flow	Cumulative Cash Flow
	($15,824)					($15,824)	($15,824)
1		$0	$1,484	($552)	$932	$932	($14,892)
2		$0	$1,521	($552)	$969	$969	($13,923)
3		$0	$1,559	($552)	$1,007	$1,007	($12,916)
4		$0	$1,598	($552)	$1,046	$1,046	($11,870)
5		$0	$1,638	($552)	$1,086	$1,086	($10,784)
6		$0	$1,679	($552)	$1,127	$1,127	($9,657)
7		$0	$1,721	($552)	$1,169	$1,169	($8,488)
8		$0	$1,764	($552)	$1,212	$1,212	($7,276)
9		$0	$1,808	($552)	$1,256	$1,256	($6,019)
10		$0	$1,853	($552)	$1,301	$1,301	($4,718)
11		($32)	$1,900	($552)	$1,348	$1,316	($3,403)
12		($32)	$1,947	($552)	$1,395	$1,363	($2,039)
13		($32)	$1,996	($552)	$1,444	$1,412	($628)
14		($32)	$2,046	($552)	$1,494	$1,462	$834
15		($2,272)	$2,097	($552)	$1,545	($727)	$107
16		($32)	$2,149	($552)	$1,597	$1,565	$1,672
17		($32)	$2,203	($552)	$1,651	$1,619	$3,291
18		($32)	$2,258	($552)	$1,706	$1,674	$4,965
19		($32)	$2,315	($552)	$1,763	$1,731	$6,696
20		($32)	$2,372	($552)	$1,820	$1,788	$8,484

Appendix C: Central Valley School System Pro Forma

Summary of Results

Project: Central Valley USD

Scenario	PPA Start Price ($/kWh)	PPA Escalator	System Cost ($/kWh)	Net Operating Benefit Year 1	Net Operating Benefit Years 1-5	Net Operating Benefit Years 1-25
NEM 1.0 PPA	$ 0.1425	2.90%	n/a	$ 170,161	$ 893,148	$ 5,752,665
NEM 2.0 PPA	$ 0.1425	2.90%	n/a	$ (41,735)	$ (215,423)	$ (1,267,808)
NEM 1.0 COP Financing (4.00%)	n/a	n/a	$ 3.05	$ 43,485	$ 370,082	$ 8,068,847
NEM 2.0 COP Financing (4.00%)	n/a	n/a	$ 3.05	$ (139,341)	$ (618,663)	$ 507,257
NEM 1.0 CREBs Financing (2.00%)	n/a	n/a	$ 3.05	$ 142,090	$ 863,110	$ 10,040,959
NEM 2.0 CREBs Financing (2.00%)	n/a	n/a	$ 3.05	$ (63,510)	$ (239,510)	$ 2,023,869

Meter	Included (Y/N)	Customer Usage (kWh)	NEM 1.0 Production (kWh)	NEM 1.0 Size (kW)	NEM 2.0 Production (kWh)	NEM 2.0 Size (kW)
1 - HIGH SCHOOL	Y	2,029,384	262,508	182	194,748	135
2 - SCHOOL	Y	1,054,184	976,349	677	605,883	420
3 - ELEMENTARY SCHOOL	Y	330,722	103,441	72	85,112	59
4 - CLASSROOMS	Y	316,117	313,799	218	207,731	144
5 - ELEMENTARY SCHOOL	Y	296,165	92,581	64	77,899	54
6 - CHARTER SCHOOL	Y	114,732	299,226	207	183,208	127
7 - SCHOOL CLASS ROOM	Y	94,055	1,644,540	1,140	1,477,201	1,024
8 - SCHOOL GARAGE	Y	75,220	61,121	42	53,375	38
Total		**4,310,579**	**3,753,565**	**2,602**	**2,885,158**	**2,001**

Disclaimers and Assumptions:

With both scenarios NEM 1.0 (current Net Energy Metering) and NEM 2.0 (proposed Net Energy Metering), the system size and production target is the optima point where annual savings are maximized against the cost of construction and operating expenses. Smaller system sizes would yield lower savings and large system sizes would not create enough benefit to outweigh the additional cost of solar production.

Project Name: Central Valley USD
Scenario #1: NEM 1.0 PPA

	Electricity Assumptions		Avoided Cost and Revenue		Expenses			Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	**Subtotal: Annual Gross Benefits**	PPA Payments	Asset Management Service	**Subtotal: Annual Operating Expenses**	Net Benefits	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	3,753,565	$ 0.1978	$ 742,579	$ 742,579	$ (534,883)	$ (37,536)	$ (572,419)	$ 170,161	$ 170,161
2	3,725,413	$ 0.2038	$ 759,120	$ 759,120	$ (546,267)	$ (38,558)	$ (584,825)	$ 174,296	$ 344,456
3	3,697,472	$ 0.2099	$ 776,030	$ 776,030	$ (557,893)	$ (39,608)	$ (597,501)	$ 178,529	$ 522,985
4	3,669,741	$ 0.2162	$ 793,316	$ 793,316	$ (569,766)	$ (40,687)	$ (610,453)	$ 182,863	$ 705,848
5	3,642,218	$ 0.2227	$ 810,987	$ 810,987	$ (581,892)	$ (41,795)	$ (623,687)	$ 187,300	$ 893,148
6	3,614,902	$ 0.2293	$ 829,052	$ 829,052	$ (594,276)	$ (42,934)	$ (637,210)	$ 191,842	$ 1,084,990
7	3,587,790	$ 0.2362	$ 847,519	$ 847,519	$ (606,924)	$ (44,103)	$ (651,027)	$ 196,492	$ 1,281,482
8	3,560,881	$ 0.2433	$ 866,397	$ 866,397	$ (619,841)	$ (45,304)	$ (665,145)	$ 201,252	$ 1,482,734
9	3,534,175	$ 0.2506	$ 885,696	$ 885,696	$ (633,032)	$ (46,538)	$ (679,571)	$ 206,126	$ 1,688,860
10	3,507,668	$ 0.2581	$ 905,425	$ 905,425	$ (646,505)	$ (47,806)	$ (694,311)	$ 211,114	$ 1,899,974
11	3,481,361	$ 0.2659	$ 925,593	$ 925,593	$ (660,264)	$ (49,108)	$ (709,372)	$ 216,221	$ 2,116,195
12	3,455,251	$ 0.2738	$ 946,211	$ 946,211	$ (674,316)	$ (50,446)	$ (724,762)	$ 221,449	$ 2,337,645
13	3,429,336	$ 0.2821	$ 967,288	$ 967,288	$ (688,667)	$ (51,820)	$ (740,487)	$ 226,801	$ 2,564,446
14	3,403,616	$ 0.2905	$ 988,834	$ 988,834	$ (703,324)	$ (53,231)	$ (756,555)	$ 232,279	$ 2,796,725
15	3,378,089	$ 0.2992	$ 1,010,861	$ 1,010,861	$ (718,292)	$ (54,681)	$ (772,973)	$ 237,887	$ 3,034,612
16	3,352,753	$ 0.3082	$ 1,033,377	$ 1,033,377	$ (733,579)	$ (56,170)	$ (789,750)	$ 243,628	$ 3,278,240
17	3,327,608	$ 0.3175	$ 1,056,396	$ 1,056,396	$ (749,192)	$ (57,700)	$ (806,892)	$ 249,504	$ 3,527,744
18	3,302,651	$ 0.3270	$ 1,079,927	$ 1,079,927	$ (765,136)	$ (59,272)	$ (824,408)	$ 255,519	$ 3,783,263
19	3,277,881	$ 0.3368	$ 1,103,983	$ 1,103,983	$ (781,420)	$ (60,886)	$ (842,307)	$ 261,676	$ 4,044,938
20	3,253,297	$ 0.3469	$ 1,128,574	$ 1,128,574	$ (798,051)	$ (62,545)	$ (860,596)	$ 267,978	$ 4,312,916
21	3,228,897	$ 0.3573	$ 1,153,713	$ 1,153,713	$ (815,036)	$ (64,248)	$ (879,284)	$ 274,429	$ 4,587,345
22	3,204,680	$ 0.3680	$ 1,179,412	$ 1,179,412	$ (832,382)	$ (65,998)	$ (898,380)	$ 281,032	$ 4,868,377
23	3,180,645	$ 0.3791	$ 1,205,683	$ 1,205,683	$ (850,097)	$ (67,796)	$ (917,893)	$ 287,791	$ 5,156,168
24	3,156,790	$ 0.3904	$ 1,232,540	$ 1,232,540	$ (868,189)	$ (69,642)	$ (937,831)	$ 294,708	$ 5,450,876
25	3,133,114	$ 0.4022	$ 1,259,994	$ 1,259,994	$ (886,666)	$ (71,539)	$ (958,205)	$ 301,789	$ 5,752,665
Totals	**85,859,796**		**$ 24,488,506**	**$ 24,488,506**	**$ (17,415,889)**	**$ (1,319,952)**	**$ (18,735,841)**	**$ 5,752,665**	**$ 5,752,665**

Key Project Assumptions	
Total Project Size (MW, DC):	2.60 MW
Estimated Cost of Utility Escalator:	3.00%
PPA Rate	$0.1425
PPA Annual Escalator	2.90%
Asset Management Services ($/kWh) PPA	$0.0100
Asset Management Services Escalator	3.50%

Project Name: Central Valley USD
Scenario #2: NEM 2.0 PPA

	Electricity Assumptions		Avoided Cost and Revenue		Expenses			Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	**Subtotal: Annual Gross Benefits**	PPA Payments	Asset Management Service	**Subtotal: Annual Operating Expenses**	Net Benefits	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	2,885,158	$ 0.1380	$ 398,252	$ 398,252	$ (411,135)	$ (28,852)	$ (439,987)	$ (41,735)	$ (41,735)
2	2,863,519	$ 0.1422	$ 407,123	$ 407,123	$ (419,885)	$ (29,637)	$ (449,522)	$ (42,400)	$ (84,134)
3	2,842,043	$ 0.1464	$ 416,191	$ 416,191	$ (428,821)	$ (30,445)	$ (459,266)	$ (43,074)	$ (127,209)
4	2,820,727	$ 0.1508	$ 425,462	$ 425,462	$ (437,948)	$ (31,274)	$ (469,221)	$ (43,759)	$ (170,968)
5	2,799,572	$ 0.1554	$ 434,939	$ 434,939	$ (447,268)	$ (32,126)	$ (479,394)	$ (44,455)	$ (215,423)
6	2,778,575	$ 0.1600	$ 444,628	$ 444,628	$ (456,787)	$ (33,001)	$ (489,788)	$ (45,160)	$ (260,583)
7	2,757,736	$ 0.1648	$ 454,532	$ 454,532	$ (466,509)	$ (33,900)	$ (500,408)	$ (45,877)	$ (306,460)
8	2,737,053	$ 0.1698	$ 464,656	$ 464,656	$ (476,437)	$ (34,823)	$ (511,260)	$ (46,604)	$ (353,064)
9	2,716,525	$ 0.1749	$ 475,007	$ 475,007	$ (486,577)	$ (35,771)	$ (522,348)	$ (47,342)	$ (400,405)
10	2,696,151	$ 0.1801	$ 485,587	$ 485,587	$ (496,933)	$ (36,746)	$ (533,678)	$ (48,091)	$ (448,496)
11	2,675,930	$ 0.1855	$ 496,404	$ 496,404	$ (507,509)	$ (37,747)	$ (545,255)	$ (48,851)	$ (497,348)
12	2,655,860	$ 0.1911	$ 507,461	$ 507,461	$ (518,310)	$ (38,775)	$ (557,084)	$ (49,623)	$ (546,971)
13	2,635,941	$ 0.1968	$ 518,765	$ 518,765	$ (529,340)	$ (39,831)	$ (569,171)	$ (50,406)	$ (597,377)
14	2,616,172	$ 0.2027	$ 530,320	$ 530,320	$ (540,606)	$ (40,916)	$ (581,522)	$ (51,202)	$ (648,579)
15	2,596,551	$ 0.2088	$ 542,133	$ 542,133	$ (552,112)	$ (42,030)	$ (594,142)	$ (52,009)	$ (700,588)
16	2,577,076	$ 0.2151	$ 554,209	$ 554,209	$ (563,862)	$ (43,175)	$ (607,037)	$ (52,828)	$ (753,415)
17	2,557,748	$ 0.2215	$ 566,554	$ 566,554	$ (575,862)	$ (44,351)	$ (620,213)	$ (53,659)	$ (807,074)
18	2,538,565	$ 0.2282	$ 579,174	$ 579,174	$ (588,118)	$ (45,559)	$ (633,677)	$ (54,503)	$ (861,577)
19	2,519,526	$ 0.2350	$ 592,075	$ 592,075	$ (600,635)	$ (46,800)	$ (647,435)	$ (55,359)	$ (916,936)
20	2,500,630	$ 0.2420	$ 605,264	$ 605,264	$ (613,418)	$ (48,075)	$ (661,492)	$ (56,229)	$ (973,165)
21	2,481,875	$ 0.2493	$ 618,746	$ 618,746	$ (626,473)	$ (49,384)	$ (675,857)	$ (57,111)	$ (1,030,276)
22	2,463,261	$ 0.2568	$ 632,529	$ 632,529	$ (639,806)	$ (50,729)	$ (690,535)	$ (58,006)	$ (1,088,282)
23	2,444,786	$ 0.2645	$ 646,618	$ 646,618	$ (653,422)	$ (52,111)	$ (705,533)	$ (58,915)	$ (1,147,197)
24	2,426,450	$ 0.2724	$ 661,022	$ 661,022	$ (667,329)	$ (53,530)	$ (720,859)	$ (59,837)	$ (1,207,034)
25	2,408,252	$ 0.2806	$ 675,746	$ 675,746	$ (681,531)	$ (54,988)	$ (736,520)	$ (60,774)	$ (1,267,808)
Totals	**65,995,681**		**$ 13,133,398**	**$ 13,133,398**	**$ (13,386,632)**	**$ (1,014,574)**	**$ (14,401,206)**	**$ (1,267,808)**	**$ (1,267,808)**

Key Project Assumptions	
Total Project Size (MW, DC):	2.00 MW
Estimated Cost of Utility Escalator:	3.00%
PPA Rate	$0.1425
PPA Annual Escalator	2.90%
Asset Management Services ($/kWh) PPA	$0.0100
Asset Management Services Escalator	3.50%

Project Name: Central Valley USD
Scenario #3: NEM 1.0 COP Financing (4.00%)

	Electricity Assumptions		Avoided Cost and Revenue			Expenses						NOB	Financing & Reporting Outflows		Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	Renewable Energy Certificates (RECs)	**Subtotal: Annual Gross Benefits**	Asset Management Service	Contingency Reserve Fund	Module Washing (2 per Year)	Inverter Replacement	Insurance	**Subtotal: Annual Operating Expenses**	**Net Operating Benefits Available for Debt Service**	Primary Financing COP	**Subtotal: Annual Debt Service**	Net Benefits After Debt Service	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	3,753,565	$ 0.1978	$ 742,579	$ -	$ 742,579	$ (82,578)	$ (19,515)	$ (10,408)	$ -	$ (2,645)	$ (115,147)	$ 627,433	$ (583,948)	$ (583,948)	$ 43,485	$ 43,485
2	3,725,413	$ 0.2038	$ 759,120	$ 3,754	$ 762,874	$ (84,828)	$ (20,003)	$ (10,668)	$ -	$ (2,698)	$ (118,197)	$ 644,677	$ (583,948)	$ (583,948)	$ 60,729	$ 104,214
3	3,697,472	$ 0.2099	$ 776,030	$ 3,725	$ 779,755	$ (87,138)	$ (20,503)	$ (10,935)	$ -	$ (2,752)	$ (121,328)	$ 658,427	$ (583,948)	$ (583,948)	$ 74,479	$ 178,693
4	3,669,741	$ 0.2162	$ 793,316	$ 3,697	$ 797,013	$ (89,512)	$ (21,015)	$ (11,208)	$ -	$ (2,807)	$ (124,542)	$ 672,471	$ (583,948)	$ (583,948)	$ 88,523	$ 267,215
5	3,642,218	$ 0.2227	$ 810,987	$ 3,670	$ 814,657	$ (91,950)	$ (21,541)	$ (11,488)	$ -	$ (2,863)	$ (127,842)	$ 686,814	$ (583,948)	$ (583,948)	$ 102,866	$ 370,082
6	3,614,902	$ 0.2293	$ 829,052	$ 3,642	$ 832,694	$ (94,454)	$ (22,079)	$ (11,776)	$ -	$ (2,921)	$ (131,230)	$ 701,464	$ (583,948)	$ (583,948)	$ 117,516	$ 487,598
7	3,587,790	$ 0.2362	$ 847,519	$ 5,422	$ 852,941	$ (97,027)	$ (22,631)	$ (12,070)	$ -	$ (2,979)	$ (134,707)	$ 718,234	$ (583,948)	$ (583,948)	$ 134,286	$ 621,883
8	3,560,881	$ 0.2433	$ 866,397	$ 5,382	$ 871,779	$ (99,670)	$ (23,197)	$ (12,372)	$ -	$ (3,039)	$ (138,277)	$ 733,502	$ (583,948)	$ (583,948)	$ 149,554	$ 771,437
9	3,534,175	$ 0.2506	$ 885,696	$ 5,341	$ 891,038	$ (102,384)	$ (23,777)	$ (12,681)	$ -	$ (3,099)	$ (141,942)	$ 749,096	$ (583,948)	$ (583,948)	$ 165,148	$ 936,585
10	3,507,668	$ 0.2581	$ 905,425	$ 5,301	$ 910,726	$ (105,173)	$ (24,371)	$ (12,998)	$ -	$ (3,161)	$ (145,704)	$ 765,022	$ (583,948)	$ (583,948)	$ 181,074	$ 1,117,659
11	3,481,361	$ 0.2659	$ 925,593	$ 5,262	$ 930,855	$ (108,038)	$ (24,981)	$ (13,323)	$ -	$ (3,225)	$ (149,566)	$ 781,289	$ (583,948)	$ (583,948)	$ 197,341	$ 1,315,000
12	3,455,251	$ 0.2738	$ 946,211	$ 6,963	$ 953,174	$ (110,980)	$ (25,605)	$ (13,656)	$ -	$ (3,289)	$ (153,531)	$ 799,643	$ (583,948)	$ (583,948)	$ 215,695	$ 1,530,694
13	3,429,336	$ 0.2821	$ 967,288	$ 6,911	$ 974,198	$ (114,003)	$ (26,245)	$ (13,998)	$ -	$ (3,355)	$ (157,601)	$ 816,597	$ (583,948)	$ (583,948)	$ 232,649	$ 1,763,344
14	3,403,616	$ 0.2905	$ 988,834	$ 6,859	$ 995,693	$ (117,108)	$ (26,901)	$ (14,347)	$ -	$ (3,422)	$ (161,779)	$ 833,914	$ (583,948)	$ (583,948)	$ 249,965	$ 2,013,309
15	3,378,089	$ 0.2992	$ 1,010,861	$ 6,807	$ 1,017,668	$ (120,298)	$ (27,574)	$ (14,706)	$ -	$ (3,490)	$ (166,069)	$ 851,599	$ (583,948)	$ (583,948)	$ 267,651	$ 2,280,960
16	3,352,753	$ 0.3082	$ 1,033,377	$ 6,756	$ 1,040,134	$ (123,575)	$ (28,263)	$ (15,074)	$ -	$ (3,560)	$ (170,472)	$ 869,661	$ (583,948)	$ (583,948)	$ 285,713	$ 2,566,673
17	3,327,608	$ 0.3175	$ 1,056,396	$ 8,382	$ 1,064,778	$ (126,941)	$ (28,970)	$ (15,451)	$ -	$ (3,631)	$ (174,993)	$ 889,785	$ (583,948)	$ (583,948)	$ 305,837	$ 2,872,511
18	3,302,651	$ 0.3270	$ 1,079,927	$ 8,319	$ 1,088,246	$ (130,398)	$ (29,694)	$ (15,837)	$ -	$ (3,704)	$ (179,633)	$ 908,613	$ (583,948)	$ (583,948)	$ 324,665	$ 3,197,175
19	3,277,881	$ 0.3368	$ 1,103,983	$ 8,257	$ 1,112,239	$ (133,950)	$ (30,437)	$ (16,233)	$ -	$ (3,778)	$ (184,397)	$ 927,842	$ (583,948)	$ (583,948)	$ 343,894	$ 3,541,069
20	3,253,297	$ 0.3469	$ 1,128,574	$ 8,195	$ 1,136,768	$ (137,598)	$ (31,197)	$ (16,639)	$ -	$ (3,854)	$ (189,288)	$ 947,480	$ (583,948)	$ (583,948)	$ 363,532	$ 3,904,601
21	3,228,897	$ 0.3573	$ 1,153,713	$ 8,133	$ 1,161,846	$ (141,346)	$ (31,977)	$ (17,055)	$ (177,813)	$ (3,931)	$ (372,122)	$ 789,724	$ -	$ -	$ 789,724	$ 4,694,325
22	3,204,680	$ 0.3680	$ 1,179,412	$ 9,687	$ 1,189,098	$ (145,196)	$ (32,777)	$ (17,481)	$ (177,813)	$ (4,009)	$ (377,276)	$ 811,822	$ -	$ -	$ 811,822	$ 5,506,147
23	3,180,645	$ 0.3791	$ 1,205,683	$ 9,614	$ 1,215,297	$ (149,151)	$ (33,596)	$ (17,918)	$ (177,813)	$ (4,090)	$ (382,568)	$ 832,729	$ -	$ -	$ 832,729	$ 6,338,877
24	3,156,790	$ 0.3904	$ 1,232,540	$ 9,542	$ 1,242,082	$ (153,213)	$ (34,436)	$ (18,366)	$ (177,813)	$ (4,171)	$ (388,000)	$ 854,082	$ -	$ -	$ 854,082	$ 7,192,958
25	3,133,114	$ 0.4022	$ 1,259,994	$ 9,470	$ 1,269,465	$ (157,386)	$ (35,297)	$ (18,825)	$ (177,813)	$ (4,255)	$ (393,576)	$ 875,888	$ -	$ -	$ 875,888	$ 8,068,847
Totals	**85,859,796**		**$ 24,488,506**	**$ 159,090**	**$ 24,647,597**	**$ (2,903,895)**	**$ (666,584)**	**$ (355,512)**	**$ (889,065)**	**$ (84,731)**	**$ (4,899,787)**	**$ 19,747,810**	**$ (11,678,963)**	**$ (11,678,963)**	**$ 8,068,847**	**$ 8,068,847**

Key Project Assumptions	
Total Project Size (MW, DC):	2.60 MW
Estimated Cost of Utility Escalator:	3.00%
Total Project Cost (including Financing COI):	$7,936,046
Asset Management Services ($/kWh)	$0.0220
Asset Management Services Escalator	3.50%

Project Name: Central Valley USD
Scenario #4: NEM 2.0 COP Financing (4.00%)

	Electricity Assumptions		Avoided Cost and Revenue			Expenses						NOB	Financing & Reporting Outflows		Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	Renewable Energy Certificates (RECs)	**Subtotal: Annual Gross Benefits**	Asset Management Service	Contingency Reserve Fund	Module Washing (2 per Year)	Inverter Replacement	Insurance	**Subtotal: Annual Operating Expenses**	**Net Operating Benefits Available for Debt Service**	Primary Financing COP	**Subtotal: Annual Debt Service**	Net Benefits After Debt Service	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	2,885,158	$ 0.1380	$ 398,252	$ -	$ 398,252	$ (63,473)	$ (15,008)	$ (8,004)	$ -	$ (2,034)	$ (88,519)	$ 309,732	$ (449,073)	$ (449,073)	$ (139,341)	$ (139,341)
2	2,863,519	$ 0.1422	$ 407,123	$ 2,885	$ 410,008	$ (65,202)	$ (15,383)	$ (8,204)	$ -	$ (2,075)	$ (90,864)	$ 319,144	$ (449,073)	$ (449,073)	$ (129,929)	$ (269,270)
3	2,842,043	$ 0.1464	$ 416,191	$ 2,864	$ 419,055	$ (66,978)	$ (15,767)	$ (8,409)	$ -	$ (2,117)	$ (93,271)	$ 325,784	$ (449,073)	$ (449,073)	$ (123,289)	$ (392,559)
4	2,820,727	$ 0.1508	$ 425,462	$ 2,842	$ 428,304	$ (68,803)	$ (16,161)	$ (8,619)	$ -	$ (2,159)	$ (95,742)	$ 332,562	$ (449,073)	$ (449,073)	$ (116,511)	$ (509,071)
5	2,799,572	$ 0.1554	$ 434,939	$ 2,821	$ 437,760	$ (70,677)	$ (16,565)	$ (8,835)	$ -	$ (2,202)	$ (98,279)	$ 339,481	$ (449,073)	$ (449,073)	$ (109,592)	$ (618,663)
6	2,778,575	$ 0.1600	$ 444,628	$ 2,800	$ 447,427	$ (72,602)	$ (16,980)	$ (9,056)	$ -	$ (2,246)	$ (100,883)	$ 346,544	$ (449,073)	$ (449,073)	$ (102,529)	$ (721,192)
7	2,757,736	$ 0.1648	$ 454,532	$ 4,168	$ 458,699	$ (74,579)	$ (17,404)	$ (9,282)	$ -	$ (2,291)	$ (103,556)	$ 355,143	$ (449,073)	$ (449,073)	$ (93,930)	$ (815,122)
8	2,737,053	$ 0.1698	$ 464,656	$ 4,137	$ 468,793	$ (76,610)	$ (17,839)	$ (9,514)	$ -	$ (2,337)	$ (106,301)	$ 362,492	$ (449,073)	$ (449,073)	$ (86,581)	$ (901,703)
9	2,716,525	$ 0.1749	$ 475,007	$ 4,106	$ 479,112	$ (78,697)	$ (18,285)	$ (9,752)	$ -	$ (2,384)	$ (109,118)	$ 369,994	$ (449,073)	$ (449,073)	$ (79,079)	$ (980,782)
10	2,696,151	$ 0.1801	$ 485,587	$ 4,075	$ 489,662	$ (80,841)	$ (18,742)	$ (9,996)	$ -	$ (2,431)	$ (112,010)	$ 377,652	$ (449,073)	$ (449,073)	$ (71,421)	$ (1,052,203)
11	2,675,930	$ 0.1855	$ 496,404	$ 4,044	$ 500,448	$ (83,043)	$ (19,211)	$ (10,246)	$ -	$ (2,480)	$ (114,979)	$ 385,469	$ (449,073)	$ (449,073)	$ (63,604)	$ (1,115,807)
12	2,655,860	$ 0.1911	$ 507,461	$ 5,352	$ 512,813	$ (85,304)	$ (19,691)	$ (10,502)	$ -	$ (2,529)	$ (118,027)	$ 394,786	$ (449,073)	$ (449,073)	$ (54,287)	$ (1,170,094)
13	2,635,941	$ 0.1968	$ 518,765	$ 5,312	$ 524,077	$ (87,628)	$ (20,183)	$ (10,764)	$ -	$ (2,580)	$ (121,156)	$ 402,921	$ (449,073)	$ (449,073)	$ (46,152)	$ (1,216,247)
14	2,616,172	$ 0.2027	$ 530,320	$ 5,272	$ 535,592	$ (90,015)	$ (20,688)	$ (11,034)	$ -	$ (2,632)	$ (124,368)	$ 411,224	$ (449,073)	$ (449,073)	$ (37,849)	$ (1,254,096)
15	2,596,551	$ 0.2088	$ 542,133	$ 5,232	$ 547,366	$ (92,466)	$ (21,205)	$ (11,309)	$ -	$ (2,684)	$ (127,665)	$ 419,700	$ (449,073)	$ (449,073)	$ (29,373)	$ (1,283,469)
16	2,577,076	$ 0.2151	$ 554,209	$ 5,193	$ 559,402	$ (94,985)	$ (21,735)	$ (11,592)	$ -	$ (2,738)	$ (131,051)	$ 428,352	$ (449,073)	$ (449,073)	$ (20,721)	$ (1,304,190)
17	2,557,748	$ 0.2215	$ 566,554	$ 6,443	$ 572,997	$ (97,572)	$ (22,279)	$ (11,882)	$ -	$ (2,793)	$ (134,526)	$ 438,471	$ (449,073)	$ (449,073)	$ (10,602)	$ (1,314,792)
18	2,538,565	$ 0.2282	$ 579,174	$ 6,394	$ 585,569	$ (100,230)	$ (22,836)	$ (12,179)	$ -	$ (2,849)	$ (138,093)	$ 447,476	$ (449,073)	$ (449,073)	$ (1,598)	$ (1,316,389)
19	2,519,526	$ 0.2350	$ 592,075	$ 6,346	$ 598,422	$ (102,960)	$ (23,407)	$ (12,484)	$ -	$ (2,906)	$ (141,755)	$ 456,666	$ (449,073)	$ (449,073)	$ 7,593	$ (1,308,796)
20	2,500,630	$ 0.2420	$ 605,264	$ 6,299	$ 611,563	$ (105,764)	$ (23,992)	$ (12,796)	$ -	$ (2,964)	$ (145,515)	$ 466,047	$ (449,073)	$ (449,073)	$ 16,974	$ (1,291,822)
21	2,481,875	$ 0.2493	$ 618,746	$ 6,252	$ 624,998	$ (108,645)	$ (24,592)	$ (13,115)	$ (136,743)	$ (3,023)	$ (286,118)	$ 338,879	$ -	$ -	$ 338,879	$ (952,942)
22	2,463,261	$ 0.2568	$ 632,529	$ 7,446	$ 639,974	$ (111,604)	$ (25,206)	$ (13,443)	$ (136,743)	$ (3,083)	$ (290,081)	$ 349,894	$ -	$ -	$ 349,894	$ (603,048)
23	2,444,786	$ 0.2645	$ 646,618	$ 7,390	$ 654,008	$ (114,644)	$ (25,836)	$ (13,779)	$ (136,743)	$ (3,145)	$ (294,148)	$ 359,860	$ -	$ -	$ 359,860	$ (243,189)
24	2,426,450	$ 0.2724	$ 661,022	$ 7,334	$ 668,356	$ (117,767)	$ (26,482)	$ (14,124)	$ (136,743)	$ (3,208)	$ (298,324)	$ 370,032	$ -	$ -	$ 370,032	$ 126,843
25	2,408,252	$ 0.2806	$ 675,746	$ 7,279	$ 683,025	$ (120,974)	$ (27,144)	$ (14,477)	$ (136,743)	$ (3,272)	$ (302,611)	$ 380,414	$ -	$ -	$ 380,414	$ 507,257
Totals	**65,995,681**		**$ 13,133,398**	**$ 122,284**	**$ 13,255,682**	**$ (2,232,064)**	**$ (512,623)**	**$ (273,399)**	**$ (683,717)**	**$ (65,161)**	**$ (3,766,963)**	**$ 9,488,719**	**$ (8,981,462)**	**$ (8,981,462)**	**$ 507,257**	**$ 507,257**

Key Project Assumptions	
Total Project Size (MW, DC):	2.00 MW
Estimated Cost of Utility Escalator:	3.00%
Total Project Cost (including Financing COI):	$6,103,050
Asset Management Services ($/kWh)	$0.0220
Asset Management Services Escalator	3.50%

Project Name: Central Valley USD
Scenario #5: NEM 1.0 CREBs Financing (2.00%)

	Electricity Assumptions		Avoided Cost and Revenue			Expenses						NOB	Financing & Reporting Outflows		Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	Renewable Energy Certificates (RECs)	**Subtotal: Annual Gross Benefits**	Asset Management Service	Contingency Reserve Fund	Module Washing (2 per Year)	Inverter Replacement	Insurance	**Subtotal: Annual Operating Expenses**	**Net Operating Benefits Available for Debt Service**	Primary Financing COP	**Subtotal: Annual Debt Service**	Net Benefits After Debt Service	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	3,753,565	$ 0.1978	$ 742,579	$ -	$ 742,579	$ (82,578)	$ (19,515)	$ (10,408)	$ -	$ (2,645)	$ (115,147)	$ 627,433	$ (485,343)	$ (485,343)	$ 142,090	$ 142,090
2	3,725,413	$ 0.2038	$ 759,120	$ 3,754	$ 762,874	$ (84,828)	$ (20,003)	$ (10,668)	$ -	$ (2,698)	$ (118,197)	$ 644,677	$ (485,343)	$ (485,343)	$ 159,335	$ 301,425
3	3,697,472	$ 0.2099	$ 776,030	$ 3,725	$ 779,755	$ (87,138)	$ (20,503)	$ (10,935)	$ -	$ (2,752)	$ (121,328)	$ 658,427	$ (485,343)	$ (485,343)	$ 173,085	$ 474,509
4	3,669,741	$ 0.2162	$ 793,316	$ 3,697	$ 797,013	$ (89,512)	$ (21,015)	$ (11,208)	$ -	$ (2,807)	$ (124,542)	$ 672,471	$ (485,343)	$ (485,343)	$ 187,128	$ 661,638
5	3,642,218	$ 0.2227	$ 810,987	$ 3,670	$ 814,657	$ (91,950)	$ (21,541)	$ (11,488)	$ -	$ (2,863)	$ (127,842)	$ 686,814	$ (485,343)	$ (485,343)	$ 201,472	$ 863,110
6	3,614,902	$ 0.2293	$ 829,052	$ 3,642	$ 832,694	$ (94,454)	$ (22,079)	$ (11,776)	$ -	$ (2,921)	$ (131,230)	$ 701,464	$ (485,343)	$ (485,343)	$ 216,122	$ 1,079,231
7	3,587,790	$ 0.2362	$ 847,519	$ 5,422	$ 852,941	$ (97,027)	$ (22,631)	$ (12,070)	$ -	$ (2,979)	$ (134,707)	$ 718,234	$ (485,343)	$ (485,343)	$ 232,891	$ 1,312,123
8	3,560,881	$ 0.2433	$ 866,397	$ 5,382	$ 871,779	$ (99,670)	$ (23,197)	$ (12,372)	$ -	$ (3,039)	$ (138,277)	$ 733,502	$ (485,343)	$ (485,343)	$ 248,159	$ 1,560,282
9	3,534,175	$ 0.2506	$ 885,696	$ 5,341	$ 891,038	$ (102,384)	$ (23,777)	$ (12,681)	$ -	$ (3,099)	$ (141,942)	$ 749,096	$ (485,343)	$ (485,343)	$ 263,753	$ 1,824,035
10	3,507,668	$ 0.2581	$ 905,425	$ 5,301	$ 910,726	$ (105,173)	$ (24,371)	$ (12,998)	$ -	$ (3,161)	$ (145,704)	$ 765,022	$ (485,343)	$ (485,343)	$ 279,680	$ 2,103,715
11	3,481,361	$ 0.2659	$ 925,593	$ 5,262	$ 930,855	$ (108,038)	$ (24,981)	$ (13,323)	$ -	$ (3,225)	$ (149,566)	$ 781,289	$ (485,343)	$ (485,343)	$ 295,946	$ 2,399,662
12	3,455,251	$ 0.2738	$ 946,211	$ 6,963	$ 953,174	$ (110,980)	$ (25,605)	$ (13,656)	$ -	$ (3,289)	$ (153,531)	$ 799,643	$ (485,343)	$ (485,343)	$ 314,300	$ 2,713,962
13	3,429,336	$ 0.2821	$ 967,288	$ 6,911	$ 974,198	$ (114,003)	$ (26,245)	$ (13,998)	$ -	$ (3,355)	$ (157,601)	$ 816,597	$ (485,343)	$ (485,343)	$ 331,255	$ 3,045,217
14	3,403,616	$ 0.2905	$ 988,834	$ 6,859	$ 995,693	$ (117,108)	$ (26,901)	$ (14,347)	$ -	$ (3,422)	$ (161,779)	$ 833,914	$ (485,343)	$ (485,343)	$ 348,571	$ 3,393,788
15	3,378,089	$ 0.2992	$ 1,010,861	$ 6,807	$ 1,017,668	$ (120,298)	$ (27,574)	$ (14,706)	$ -	$ (3,490)	$ (166,069)	$ 851,599	$ (485,343)	$ (485,343)	$ 366,257	$ 3,760,045
16	3,352,753	$ 0.3082	$ 1,033,377	$ 6,756	$ 1,040,134	$ (123,575)	$ (28,263)	$ (15,074)	$ -	$ (3,560)	$ (170,472)	$ 869,661	$ (485,343)	$ (485,343)	$ 384,319	$ 4,144,364
17	3,327,608	$ 0.3175	$ 1,056,396	$ 8,382	$ 1,064,778	$ (126,941)	$ (28,970)	$ (15,451)	$ -	$ (3,631)	$ (174,993)	$ 889,785	$ (485,343)	$ (485,343)	$ 404,443	$ 4,548,806
18	3,302,651	$ 0.3270	$ 1,079,927	$ 8,319	$ 1,088,246	$ (130,398)	$ (29,694)	$ (15,837)	$ -	$ (3,704)	$ (179,633)	$ 908,613	$ (485,343)	$ (485,343)	$ 423,270	$ 4,972,076
19	3,277,881	$ 0.3368	$ 1,103,983	$ 8,257	$ 1,112,239	$ (133,950)	$ (30,437)	$ (16,233)	$ -	$ (3,778)	$ (184,397)	$ 927,842	$ (485,343)	$ (485,343)	$ 442,499	$ 5,414,576
20	3,253,297	$ 0.3469	$ 1,128,574	$ 8,195	$ 1,136,768	$ (137,598)	$ (31,197)	$ (16,639)	$ -	$ (3,854)	$ (189,288)	$ 947,480	$ (485,343)	$ (485,343)	$ 462,138	$ 5,876,713
21	3,228,897	$ 0.3573	$ 1,153,713	$ 8,133	$ 1,161,846	$ (141,346)	$ (31,977)	$ (17,055)	$ (177,813)	$ (3,931)	$ (372,122)	$ 789,724	$ -	$ -	$ 789,724	$ 6,666,438
22	3,204,680	$ 0.3680	$ 1,179,412	$ 9,687	$ 1,189,098	$ (145,196)	$ (32,777)	$ (17,481)	$ (177,813)	$ (4,009)	$ (377,276)	$ 811,822	$ -	$ -	$ 811,822	$ 7,478,260
23	3,180,645	$ 0.3791	$ 1,205,683	$ 9,614	$ 1,215,297	$ (149,151)	$ (33,596)	$ (17,918)	$ (177,813)	$ (4,090)	$ (382,568)	$ 832,729	$ -	$ -	$ 832,729	$ 8,310,989
24	3,156,790	$ 0.3904	$ 1,232,540	$ 9,542	$ 1,242,082	$ (153,213)	$ (34,436)	$ (18,366)	$ (177,813)	$ (4,171)	$ (388,000)	$ 854,082	$ -	$ -	$ 854,082	$ 9,165,071
25	3,133,114	$ 0.4022	$ 1,259,994	$ 9,470	$ 1,269,465	$ (157,386)	$ (35,297)	$ (18,825)	$ (177,813)	$ (4,255)	$ (393,576)	$ 875,888	$ -	$ -	$ 875,888	$ 10,040,959
Totals	**85,859,796**		**$ 24,488,506**	**$ 159,090**	**$ 24,647,597**	**$ (2,903,895)**	**$ (666,584)**	**$ (355,512)**	**$ (889,065)**	**$ (84,731)**	**$ (4,899,787)**	**$ 19,747,810**	**$ (9,706,850)**	**$ (9,706,850)**	**$ 10,040,959**	**$ 10,040,959**

Key Project Assumptions	
Total Project Size (MW, DC):	2.60 MW
Estimated Cost of Utility Escalator:	3.00%
Total Project Cost (including Financing COI):	$7,936,046
Asset Management Services ($/kWh)	$0.0220
Asset Management Services Escalator	3.50%

Project Name: Central Valley USD
Scenario #6: NEM 2.0 CREBs Financing (2.00%)

	Electricity Assumptions		Avoided Cost and Revenue			Expenses						NOB	Financing & Reporting Outflows		Net Savings	
Year	Annual Solar Production (kWh)	Savings per kWh Produced	Avoided Cost from Solar Generation	Renewable Energy Certificates (RECs)	**Subtotal: Annual Gross Benefits**	Asset Management Service	Contingency Reserve Fund	Module Washing (2 per Year)	Inverter Replacement	Insurance	**Subtotal: Annual Operating Expenses**	**Net Operating Benefits Available for Debt Service**	Primary Financing COP	**Subtotal: Annual Debt Service**	Net Benefits After Debt Service	**Cumulative Net Benefits**
0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	2,885,158	$ 0.1380	$ 398,252	$ -	$ 398,252	$ (63,473)	$ (15,008)	$ (8,004)	$ -	$ (2,034)	$ (88,519)	$ 309,732	$ (373,243)	$ (373,243)	$ (63,510)	$ (63,510)
2	2,863,519	$ 0.1422	$ 407,123	$ 2,885	$ 410,008	$ (65,202)	$ (15,383)	$ (8,204)	$ -	$ (2,075)	$ (90,864)	$ 319,144	$ (373,243)	$ (373,243)	$ (54,099)	$ (117,609)
3	2,842,043	$ 0.1464	$ 416,191	$ 2,864	$ 419,055	$ (66,978)	$ (15,767)	$ (8,409)	$ -	$ (2,117)	$ (93,271)	$ 325,784	$ (373,243)	$ (373,243)	$ (47,459)	$ (165,068)
4	2,820,727	$ 0.1508	$ 425,462	$ 2,842	$ 428,304	$ (68,803)	$ (16,161)	$ (8,619)	$ -	$ (2,159)	$ (95,742)	$ 332,562	$ (373,243)	$ (373,243)	$ (40,681)	$ (205,748)
5	2,799,572	$ 0.1554	$ 434,939	$ 2,821	$ 437,760	$ (70,677)	$ (16,565)	$ (8,835)	$ -	$ (2,202)	$ (98,279)	$ 339,481	$ (373,243)	$ (373,243)	$ (33,762)	$ (239,510)
6	2,778,575	$ 0.1600	$ 444,628	$ 2,800	$ 447,427	$ (72,602)	$ (16,980)	$ (9,056)	$ -	$ (2,246)	$ (100,883)	$ 346,544	$ (373,243)	$ (373,243)	$ (26,699)	$ (266,208)
7	2,757,736	$ 0.1648	$ 454,532	$ 4,168	$ 458,699	$ (74,579)	$ (17,404)	$ (9,282)	$ -	$ (2,291)	$ (103,556)	$ 355,143	$ (373,243)	$ (373,243)	$ (18,099)	$ (284,308)
8	2,737,053	$ 0.1698	$ 464,656	$ 4,137	$ 468,793	$ (76,610)	$ (17,839)	$ (9,514)	$ -	$ (2,337)	$ (106,301)	$ 362,492	$ (373,243)	$ (373,243)	$ (10,750)	$ (295,058)
9	2,716,525	$ 0.1749	$ 475,007	$ 4,106	$ 479,112	$ (78,697)	$ (18,285)	$ (9,752)	$ -	$ (2,384)	$ (109,118)	$ 369,994	$ (373,243)	$ (373,243)	$ (3,248)	$ (298,307)
10	2,696,151	$ 0.1801	$ 485,587	$ 4,075	$ 489,662	$ (80,841)	$ (18,742)	$ (9,996)	$ -	$ (2,431)	$ (112,010)	$ 377,652	$ (373,243)	$ (373,243)	$ 4,409	$ (293,897)
11	2,675,930	$ 0.1855	$ 496,404	$ 4,044	$ 500,448	$ (83,043)	$ (19,211)	$ (10,246)	$ -	$ (2,480)	$ (114,979)	$ 385,469	$ (373,243)	$ (373,243)	$ 12,226	$ (281,671)
12	2,655,860	$ 0.1911	$ 507,461	$ 5,352	$ 512,813	$ (85,304)	$ (19,691)	$ (10,502)	$ -	$ (2,529)	$ (118,027)	$ 394,786	$ (373,243)	$ (373,243)	$ 21,544	$ (260,127)
13	2,635,941	$ 0.1968	$ 518,765	$ 5,312	$ 524,077	$ (87,628)	$ (20,183)	$ (10,764)	$ -	$ (2,580)	$ (121,156)	$ 402,921	$ (373,243)	$ (373,243)	$ 29,678	$ (230,449)
14	2,616,172	$ 0.2027	$ 530,320	$ 5,272	$ 535,592	$ (90,015)	$ (20,688)	$ (11,034)	$ -	$ (2,632)	$ (124,368)	$ 411,224	$ (373,243)	$ (373,243)	$ 37,982	$ (192,467)
15	2,596,551	$ 0.2088	$ 542,133	$ 5,232	$ 547,366	$ (92,466)	$ (21,205)	$ (11,309)	$ -	$ (2,684)	$ (127,665)	$ 419,700	$ (373,243)	$ (373,243)	$ 46,458	$ (146,010)
16	2,577,076	$ 0.2151	$ 554,209	$ 5,193	$ 559,402	$ (94,985)	$ (21,735)	$ (11,592)	$ -	$ (2,738)	$ (131,051)	$ 428,352	$ (373,243)	$ (373,243)	$ 55,109	$ (90,900)
17	2,557,748	$ 0.2215	$ 566,554	$ 6,443	$ 572,997	$ (97,572)	$ (22,279)	$ (11,882)	$ -	$ (2,793)	$ (134,526)	$ 438,471	$ (373,243)	$ (373,243)	$ 65,229	$ (25,671)
18	2,538,565	$ 0.2282	$ 579,174	$ 6,394	$ 585,569	$ (100,230)	$ (22,836)	$ (12,179)	$ -	$ (2,849)	$ (138,093)	$ 447,476	$ (373,243)	$ (373,243)	$ 74,233	$ 48,562
19	2,519,526	$ 0.2350	$ 592,075	$ 6,346	$ 598,422	$ (102,960)	$ (23,407)	$ (12,484)	$ -	$ (2,906)	$ (141,755)	$ 456,666	$ (373,243)	$ (373,243)	$ 83,424	$ 131,985
20	2,500,630	$ 0.2420	$ 605,264	$ 6,299	$ 611,563	$ (105,764)	$ (23,992)	$ (12,796)	$ -	$ (2,964)	$ (145,515)	$ 466,047	$ (373,243)	$ (373,243)	$ 92,805	$ 224,790
21	2,481,875	$ 0.2493	$ 618,746	$ 6,252	$ 624,998	$ (108,645)	$ (24,592)	$ (13,115)	$ (136,743)	$ (3,023)	$ (286,118)	$ 338,879	$ -	$ -	$ 338,879	$ 563,670
22	2,463,261	$ 0.2568	$ 632,529	$ 7,446	$ 639,974	$ (111,604)	$ (25,206)	$ (13,443)	$ (136,743)	$ (3,083)	$ (290,081)	$ 349,894	$ -	$ -	$ 349,894	$ 913,563
23	2,444,786	$ 0.2645	$ 646,618	$ 7,390	$ 654,008	$ (114,644)	$ (25,836)	$ (13,779)	$ (136,743)	$ (3,145)	$ (294,148)	$ 359,860	$ -	$ -	$ 359,860	$ 1,273,423
24	2,426,450	$ 0.2724	$ 661,022	$ 7,334	$ 668,356	$ (117,767)	$ (26,482)	$ (14,124)	$ (136,743)	$ (3,208)	$ (298,324)	$ 370,032	$ -	$ -	$ 370,032	$ 1,643,455
25	2,408,252	$ 0.2806	$ 675,746	$ 7,279	$ 683,025	$ (120,974)	$ (27,144)	$ (14,477)	$ (136,743)	$ (3,272)	$ (302,611)	$ 380,414	$ -	$ -	$ 380,414	$ 2,023,869
Totals	**65,995,681**		**$ 13,133,398**	**$ 122,284**	**$ 13,255,682**	**$ (2,232,064)**	**$ (512,623)**	**$ (273,399)**	**$ (683,717)**	**$ (65,161)**	**$ (3,766,963)**	**$ 9,488,719**	**$ (7,464,850)**	**$ (7,464,850)**	**$ 2,023,869**	**$ 2,023,869**

Key Project Assumptions	
Total Project Size (MW, DC):	2.00 MW
Estimated Cost of Utility Escalator:	3.00%
Total Project Cost (including Financing COI):	$6,103,050
Asset Management Services ($/kWh)	$0.0220
Asset Management Services Escalator	3.50%

Appendix D: Memorandum from Skadden, Arps on U.S. Federal Income Tax Consequences for Residential Solar Feed-In Tariffs

MEMORANDUM

August 9, 2013

TO: The Alliance For Solar Choice (TASC)

FROM: Sean Shimamoto, Partner, Skadden, Arps, Slate, Meagher & Flom LLP
Emily Lam, Partner, Skadden, Arps, Slate, Meagher & Flom LLP

RE: U.S. Federal Income Tax Consequences for Residential Solar Feed-In Tariffs

This memorandum summarizes certain U.S. federal income tax consequences regarding feed-in tariffs, value of solar tariffs, and other comparable in front of the meter solar configurations. Specifically, this memorandum will address (i) whether a residential solar system that would otherwise qualify for the Residential Energy Efficient Property credit under Section 25D[1] would so qualify under a feed-in tariff, and (ii) whether payments received by a taxpayer pursuant to a feed-in tariff constitute gross income of such taxpayer.[2]

* * *

Internal Revenue Service Circular 230 requires us to advise you that, unless otherwise expressly indicated, any U.S. federal tax advice contained in the analysis set forth below was not intended or written to be used, and cannot be used, for the purpose of (i) avoiding tax-related penalties under the Internal Revenue Code or (ii) promoting, marketing, or recommending to another party any tax-related matters addressed herein.

Background

Several states, municipalities, and investor-owned utilities have enacted various forms of feed-in tariff arrangements or Value of Solar Tariffs (collectively, "FITs") for

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1 Unless otherwise indicated, all Section references herein are to the Internal Revenue Code of 1986, as amended (the "Code").

2 This memorandum analyzes the general framework of feed-in tariffs, value of solar tariffs, and other in front of the meter configurations under current law. The precise rules governing these configurations vary by program, which differences could change the U.S. federal income tax consequences discussed herein. However, the following analysis is generally applicable to all buy all/sell all arrangements as described further below in the "Background" section.

residential solar systems. These programs generally work as follows: utilities purchase all of the electricity generated by a residential solar system either under a long term power purchase contract or a tariff that changes values based on regulatory reviews. The homeowner sells all of the electricity generated by the residential solar system in exchange for a kWh rate. Legal title to the electricity passes prior to any ability of the homeowner to consume the electricity. The arrangement is thus a "sell all" situation in which the full amount of electricity generated by the residential solar system is sold to the utility.

In a separate transaction, the utility sells electricity to the homeowner for the homeowner's personal consumption. FITs are commonly referred to as "in front of the meter" transactions. Although FITs may differ in their specific terms, the above description provides the common framework of all FITs contemplated in the following analysis.

<u>Discussion</u>

Section 25D Credit

Individual taxpayers may be eligible for a tax incentive under Section 25D known as the Residential Energy Efficient Property credit (the "Section 25D credit"), for expenditures for qualified energy efficient residential property, which includes qualified solar electric property ("QSEP").[3] For expenditures on QSEP during the tax year, taxpayers are allowed a personal tax credit in the amount of 30% of such expenditure.[4] A QSEP expenditure is an expenditure for property that uses solar energy to generate electricity "***for use in a dwelling unit***."[5] The dwelling unit must be located in the U.S. and must be used as a residence by the taxpayer.[6] Moreover, if less than 80% of the use of the property is for nonbusiness purposes in the dwelling unit,[7] only that portion of the expenditures which is properly allocable to use for nonbusiness purposes shall be taken into account.[8]

Because under FITs all of the electricity generated by the residential solar system is sold to the utility, that electricity is not used by the taxpayer/homeowner in its personal residence as expressly required to qualify for the Section 25D credit.

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3 Section 25D(a).

4 Section 25D(a)(1).

5 Section 25D(d)(2) (emphasis added). *See also* Section 3.03 of Notice 2009-41, 2009-19 I.R.B. 933, released on May 11, 2009, by the Internal Revenue Service (a taxpayer claiming a Section 25D credit with respect to an expenditure is responsible for determining whether the expenditure appropriately relates to a qualifying dwelling unit).

6 Section 25D(d)(2).

7 A nonbusiness use in a dwelling unit would not include, for example, use for a home office. Treas. Reg. § 1.23-3(g).

8 Section 25D(e)(7).

Further, as noted above, if the taxpayer is not directly using at least 80% of the electricity generated by the solar electric property for nonbusiness purposes, then the Section 25D credit is not available for that portion of business use. Under FITs, 100% of the electricity generated is sold to the utility, and thus 100% of the use of the residential solar system is for business use. Therefore, even if a residential solar system were otherwise eligible for a Section 25D credit, because all of the electricity generated is sold, none of it is used by the taxpayer for nonbusiness purposes, and thus none of the expenditures qualify for the Section 25D credit.

Gross Income

In addition to the loss of the Section 25D credit, the payments received by a taxpayer for the sale of electricity under FITs appear to fall squarely within the definition of taxable gross income. Section 61 provides that gross income means "all income from whatever source derived." In the landmark case *Commissioner v. Glenshaw Glass*, the United States Supreme Court interpreted the concept of gross income broadly, "in recognition of the intention of Congress to tax all gains except those specifically exempted," to include "instances of undeniable accessions to wealth, clearly realized, and over which the taxpayers have complete dominion."[9]

The terms of FITs provide for the sale by the taxpayer to the utility of all electricity generated by the taxpayer's residential solar system. In exchange, the utility compensates the taxpayer with either cash or a credit on the taxpayer's utility bill. Although the taxpayer may also purchase electricity from the utility, under FITs, the two transactions are separate and distinct. The proceeds from the taxpayer's sale of electricity to the utility therefore likely constitute gross income.

This conclusion is supported by Senate bill S.1225, introduced by Sen. Mark Udall, on June 26, 2013, which would add a new Section 139E to the Code to provide an income exclusion for "any gain from the sale or exchange to the electrical grid" of electricity generated by property with respect to which QSEP expenditures are eligible for a Section 25D credit, "but only to the extent such gain does not exceed the value of the electricity used at such residence during such taxable year." The proposed bill creates a clear negative inference that absent the income exclusion proposed in a new Section 139E, gain from the sale of electricity in this context constitutes gross income.

Conclusion

Under current law, residential FITs jeopardize the Section 25D credit because electricity generated by such residential solar systems is sold to the utility, rather than used in a personal residence of the taxpayer. Further, payments received by a taxpayer under FITs are likely includable in taxable gross income.

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9 348 U.S. 426, 431 (1955).

Appendix E: Chadbourne and Parke Memorandum on Residential Solar Feed-in Tariff Programs

chadbourne

Chadbourne & Parke LLP
1301 Avenue of the Americas
New York, NY 10019
telephone: (212) 408-5100

memorandum

To The Alliance For Solar Choice

From John Marciano

Date June 26, 2015

Re Residential Solar Feed-in Tariff Programs

You asked whether a residential solar system homeowner will suffer adverse tax consequences in the event that a utility shifts from a net metering program to a feed-in tariff program.[1]

To the extent a homeowner is treated as selling more than 20% of the electricity from his or her system to the utility under a feed-in tariff program, the homeowner would be ineligible for the residential solar tax credit under Section 25D[2] on all or a portion of his or her system.[3] For the reasons described below, we believe this could result in adverse tax consequences to the homeowner. Specifically, while the homeowner is potentially eligible for the business tax credit under Section 48 on the remaining portion of his or her system, various limitations on individuals in respect of business use property may act to effectively extinguish much of the value of this credit.

In contrast, under a net metering program, where the homeowner is deemed to use the utility grid to store energy that he or she uses to serve onsite loads, no portion of the

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1 This memorandum discusses feed-in tariff programs, net metering programs, and the like, in general terms. The precise rules governing these types of programs vary program by program and could result in different tax consequences.

2 All references in this memorandum to a "Section" without identifying the statute are to a section of the Internal Revenue Code of 1986, as amended through today's date.

3 Section 25D(e)(7).

homeowner’s system is business use property and the homeowner would be eligible for the full residential tax credit.

Background

Generally, under a feed-in tariff program, a utility charges each residential solar system homeowner retail rates for energy that the homeowner draws from the grid and separately purchases at lower rates all or a portion of the energy that the homeowner’s solar system generates. The utility’s payment may take the form of a cash payment or credit against the homeowner’s monthly utility bill.

In contrast, generally, under a net metering program, the utility tracks the energy delivered by each homeowner to the grid and the energy received by such homeowner from the grid, and charges the homeowner retail rates on just that net quantity.

Discussion

New solar systems used in a trade or business in the United States qualify potentially for a 30% business tax credit upon completion.[4]

While a homeowner that uses solar equipment exclusively to power his or her residence for nonbusiness purposes is not eligible for the business tax credit, there is a separate, residential tax credit that is available to him or her. The residential tax credit is available to homeowners for 30% of the cost of equipment that “uses solar energy to generate electricity for use in a dwelling unit located in the United States and used as a residence by the taxpayer.”[5]

To the extent a homeowner is treated under a net metering program as transferring power to the utility to hold until the homeowner uses such power (i.e., using the utility grid as a giant battery), the homeowner’s entire system is personal use property. However, a homeowner that receives cash or a bill reduction in exchange for power purchased pursuant to a feed-in tariff program could potentially be treated as selling power to the utility and required to treat a portion of his or her system as business use property. This raises a number of potential pitfalls for the homeowner.

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4 Section 48(a)(1).

5 Section 25D(a), (d)(2).

Credit/Loss Limitations For Business Use Property

A. If the homeowner financed his purchase with debt, the homeowner may be unable to claim the entire business tax credit in the year the system is completed. Instead all or a portion of the business tax credit could be deferred over the term of the debt under special rules called the at risk rules. [6] The residential tax credit does not have such a limitation.

B. Similarly, the business tax credit likely would be deferred even where the system is not financed with debt because special rules called the passive loss rules would allow the credit in general only against business income from the system (i.e., feed-in tariff receipts).[7] That is, generally, the homeowner would not be able to offset income from employment or other businesses with the business tax credit from the system. Thus, the passive loss rules have the effect of significantly deferring the business tax credit and do not apply to the residential tax credit.

C. The business tax credit vests over five years, 20% each year.[8] This means that the homeowner may be subject to an unexpected tax bill during any of the first five years of the system's operation, including if the system is sold or shutdown[9] or if the residence is leased to a nonresident foreign person[10]. The residential tax credit vests upon completion without restriction.

D. The homeowner may have difficultly complying with the complexities of these rules and allocating the cost of his or her system between business and nonbusiness uses. Notably, the residential tax credit and business tax credit are claimed on separate forms, the restrictions noted above are highly technical and involve many pages of regulations and the degree to which the project is either business or personal use property can change from year to year.

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[6] Section 49(a)(1).

[7] Section 469(a).

[8] Section 50(a)(1)(B).

[9] Section 50(a)(1)(A).

[10] Section 50(b)(4).

Other Implications

Feed-in tariff receipts may be includible by the homeowner in income. Further, the homeowner may be unable to deduct against such income, payments later on in the year for replacement power because the replacement power is used for personal purposes.[11]

In addition, there may be sales and use tax implications to utilities of switching from a net metering program to a feed-in tariff program. Some states treat the sale of power as subject to sales and use and other transfer taxes. Even in states where this is not the case, there may be additional record keeping and document filings required.

J.M.

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[11] Note, depreciation is technically available for the portion of the system that is business use property, however, any value is largely lost because under the at risk rules and passive loss rules described above, generally, depreciation would offset just income from the system.

Appendix F: Chun Kerr Memorandum on Residential Solar Feed-in-Tariffs

CHUN KERR LLP
a Limited Liability Law Partnership

Fort St. Tower, Topa Financial Center
745 Fort Street, 9th Floor
Honolulu, Hawaii 96813-3815
(o) 808-528-8200 (f) 808-536-5869 chunkerr.com

Writer's Direct Contact:
(808) 528-8211
rkamikawa@chunkerr.com

MEMORANDUM

TO: The Alliance for Solar Choice

FROM: Ray Kamikawa

DATE: June 1, 2015

RE: Residential Solar Feed-in-Tariffs - Hawaii income and general excise tax

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170456.2

This will provide guidance on the State of Hawaii income and general excise tax consequences of a feed-in-tariff arrangement ("FIT") should one be adopted in Hawaii to replace net-energy metering. The various forms of a FIT have as their primary nature the sale by the homeowner of electricity generated by the residential solar system to the public utility in exchange for a cash payment or credit to the homeowner's electric bills measured by an agreed kWh savings rate.

In Hawaii's case, the savings will be through a credit mechanism against the homeowner's monthly electrical bills, with any unused credit carried over month to month until exhausted or until the end of the calendar year at which time any accumulated credits are forfeited. Under one form of FIT, legal title to the electricity passes prior to any ability of the homeowner to consume the electricity. That form of FIT is referred to as a sell-all arrangement. Under another form of FIT, legal title to the electricity passes after the ability of the homeowner to consume the electricity, meaning the homeowner could only sell net excess electricity to the public utility ("NET-FIT"). Such sales may continue until the homeowner's electric bill is reduced to the regulatory minimum, i.e., a mandated minimum bill. In either case, the homeowner sells electricity to the public utility in consideration for the credits against the homeowner's electrical bills.

For income tax purposes, Hawaii conforms to the Internal Revenue Code of 1986, as amended ("IRC"), unless provided otherwise. Section 235-3(b), Hawaii Revised Statutes ("HRS"). Under section 61, IRC, to which Hawaii conforms, gross income means all income from whatever source derived, unless excluded by law. See also Treas. Reg. § 1.61-1(a)("Gross income includes income realized in any form, whether in money, property, or services.").

As applied to the instant case, the homeowner realizes gross income from the sale of electricity to a third party utility, whether under a FIT or NET FIT, for consideration in the form of property (the credits). That the credits will expire at the end of the current year does not change this result, as the homeowner has the potential use of the credits before then and the value of such associated use.

Hawaii also conforms to IRC § 136, which provides an exclusion from gross income for the value of any subsidy provided by a public utility to a customer for the purchase or installation of any energy conservation measure. Section 136, however, does not apply to the sale or exchange of property rights, as is the case with the FIT and NET FIT. See Private Letter Ruling ("PLR") 2010035003 (Internal Revenue Service ("IRS") ruled that a utility's payments to purchase renewable energy credits issued under a state program did not qualify as subsidies for purposes of IRC § 136, since the transaction involved a "sale or exchange of property and property rights.").

The credits under the FIT and NET FIT also do not qualify as rebates or purchase price adjustments that would be netted against gross income, again because they do not apply to situations where the adjustment by a seller is in return for performance or consideration by the purchaser. Pittsburgh Milk Co., v. Commissioner, 26 T.C. 707, 716-717 (1956).[1] See also In re Foodland Super Market, Ltd., 51 Haw. 281, 456 P.2d 664 (1969) (payments characterized as discounts or rebates nevertheless held to be gross income taxable under the GET where discounts or rebates were received under a cooperative merchandising agreement in return for the payee's services rendered for the manufacturer).

Hawaii also imposes a general excise tax ("GET") on gross income or gross receipts derived from trade, business, commerce and sales. HRS § 237-3. Business is defined as including "all activities (personal, professional, or corporate), engaged in or caused to be engaged in with the object of gain or economic benefit either direct or indirect." HRS § 237-2.

A homeowner selling electricity may not be considered as engaging in a business, as the homeowner is selling electricity for personal and not a business use. Nevertheless, it is

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[1] IRS Revenue Ruling 91-6, 1991-2 C.B. 17, provides for the exclusion from gross income a utility's rate reductions or credits to customers who participate in the utility company's energy conservation programs. Under these programs, participating customers acquire energy efficient products or equipment, such as insulation, storm windows and doors, air conditioners, furnaces, heat pumps, hot water heaters, appliances, or similar items. These products may be acquired from the utility company or third parties. The situation in this revenue ruling does not involve the sale or exchange of property between customers and utilities, as does the FIT and NET FIT, and is therefore inapplicable to the present situation.

possible that the sale of electricity to a utility could be viewed by the Department of Taxation, State of Hawaii (the "Department"), as subject to the GET, especially considering the Hawaii Supreme Court's broad interpretation of the coverage of the GET. See, e.g., Pratt v. Kondo, 53 Haw. 435, 436, 496 P.2d 1, 2 (1972) (the GET applies to "virtually every economic activity imaginable"). Considering the broad reach of the GET, I recommend that a ruling from the Department be obtained to obtain its position on the GET as applied to FIT and NET FIT.[2]

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[2] Such a ruling would also confirm that such sales are or are not excludible casual transactions under HRS § 237-2 (defined under HRS § 237-1 as an "occasional or isolated sale or transaction" involving tangible personal property by a person not required to be licensed under the GET or tangible personal property not ordinarily sold in the business of a person regularly engaged in business). If such sales are determined to be subject to the GET, the tax rate would be the same .5% rate as imposed on producers. HRS § 237-13.5 (GET on gross proceeds from the sale of electric power to a public utility company for resale to the public).

Appendix G: EDR, Impacts on the California Economy: Alternative Net Energy Metering Policies

MEMORANDUM

To: TASC

From: Mark Fulmer

Subject: **NEM Economic Impact Study**

Date: August 31, 2015

MRW retained Economic Development Research Group, Inc. (EDR Group) to evaluate the macroeconomic and employment impacts of net energy metering (NEM) policies. MRW selected EDR Group because of its reputation and expertise in evaluating the economic and employment costs and benefits associated with energy and environmental policies, including NEM. Most recently in California, EDR Group conducted a macroeconomic impact study of the $257 million funding from the American Recovery and Reinvestment Act of 2009 (ARRA) distributed through California Energy Commission programs. The emphasis of that study was to identify changes in jobs and dollars of gross regional products across regions of California.

The attached report presents the results of EDR Group's macroeconomic and employment assessment of NEM policies being considered in R.14-07-002. At TASC's direction, EDR Group considered three cases: TASC's August 3, 2015 proposal, assuming all its recommended Public Tool and Revenue Requirement modifications and a two-tiered residential rate; Office of Ratepayer Advocate's (ORA's) August 3, 2015 proposal; and Southern California Edison's (SCE's) August 3, 2015 proposal.

EDR Group's input data comes from Public Tool output. In order for the cases to be comparable, the input data for all three cases were generated using common Public Tool and Revenue Requirement models.[1]

Specifically, the following data was extracted from the Public Tool:

- Participant costs, accounting for all state and federal program contributions;
- Participant bill savings;
- Direct payments to participants for DEG exports that were not valued at the full retail rate;
- Utility lost rate revenues;
- Utility program costs;

[1] All cases were run using the Public Tool and Revenue Requirement models with the modifications described in the MRW Report attached to the TASC August 3 Proposal.

- Utility integration costs;
- Utility federal incentives;
- Avoided costs, including: energy, capacity, distribution, subtransmission, and transmission avoided costs; ancillary service benefits, and RPS benefits.

These values were extracted from the Public Tool “Adoption Outputs” tab. This is the same primary source from which the Public Tool draws its results tables and figures. MRW used pivot tables to extract the data for each installation year, 2017 through 2025. However the Public Tool does not track results by calendar year, only the net present value (NPV) of the various outputs for each installation year. That is, one can extract from the Public Tool the present value of all the bill savings for all the distributed energy generation installed in 2022, but it cannot report the total bill savings in the year 2022.

Because the EDR Group required annual values for each input and the Public Tool only reported NPVs, MRW had to levelize the extracted NPVs into annual cost or benefit streams. For participant costs (except government incentives), the NPVs were levelized over 20 years, which is consistent with the pro forma analysis contained in the Public Tool. The government incentives were credited in the first five years of the DEG operation, so as to approximate the benefits of accelerated depreciation. All other costs were levelized over the assumed live of the DEG systems, 25 years. Appropriate discount rates, either participant (9%) or utility (7%), were used.

This simplification will cause some year-to-year inaccuracies in the EDR Group’s results (i.e., front-loaded cost streams, and rate and cost escalations are not reflected). Nonetheless, the simplification should not affect the overall numbers and conclusions reached in the EDR Group report.

Impacts on the California Economy: Alternative Net Energy Metering Policies

Prepared for:

MRW & Associates, LLC
1814 Franklin Street, Suite 720, Oakland, CA 94612

Prepared by:

Economic Development Research Group, Inc.
155 Federal Street, Suite 600, Boston, MA 02110

August 31, 2015

Table of Contents

EXECUTIVE SUMMARY

Economic Development Research Group, Inc. (EDR Group) examined the macroeconomic impacts from three alternate visions for how the California Public Utilities Commission (CPUC) might continue (and structure) the *net energy metering* (NEM) program/policy upon its expiration. EDR Group prepared this study with MRW Associates' staff support, and report, for MRW's client, The Alliance for Solar Choice (TASC). MRW staff, using the CPUC's recent Public Tool[1] for NEM scenario investigation, framed three cases -- relative to a base case of no additional NEM installations -- which provided the majority of data needed for subsequent modeling of how the California economy would be affected.

EDR Group used a single-region REMI[2] model of the California economy to gauge impacts on annual jobs and dollars of gross state product (GSP) under each scenario. Scenarios were framed for 2017 through 2048 (when the useful life on the last round of deployed systems expire). For purposes of the study, it is assumed the NEM program will expire at the end of 2016 for new customers.

The three cases considered were:

- TASC's August 3, 2015 Proposal, assuming all its Public Tool modifications and a two-tiered residential rate structure similar to the one recently adopted by the CPUC. In this case, NEM is continued with minor changes.
- The Office of Ratepayer Advocate's (ORA's) August 3, 2015 Proposal, run using Public Tool with the modifications recommended by TASC and a two-tiered residential rate structure.
- Southern California Edison's (SCE's) August 3, 2015 Proposal, run using Public Tool with the modifications recommended by TASC and a two-tiered residential rate structure.

The REMI model is given (a) customer-segment specific participant's *net* savings (that is dollars of gross bill savings *less* cost of making improvements defrayed by state and federal incentives ; (b) increased California construction labor compensation related to the installation bill on the improvements, and a California Wholesale distribution mark-up on (100%) imported equipment expenditures related to the improvements; and (c) customer-segment specific *rate adjustments* (expressed in annual dollars) to account for

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[1] Developed by E3 and released for public use Spring 2015.
[2] Regional Economic Models, Inc. of Amherst, MA

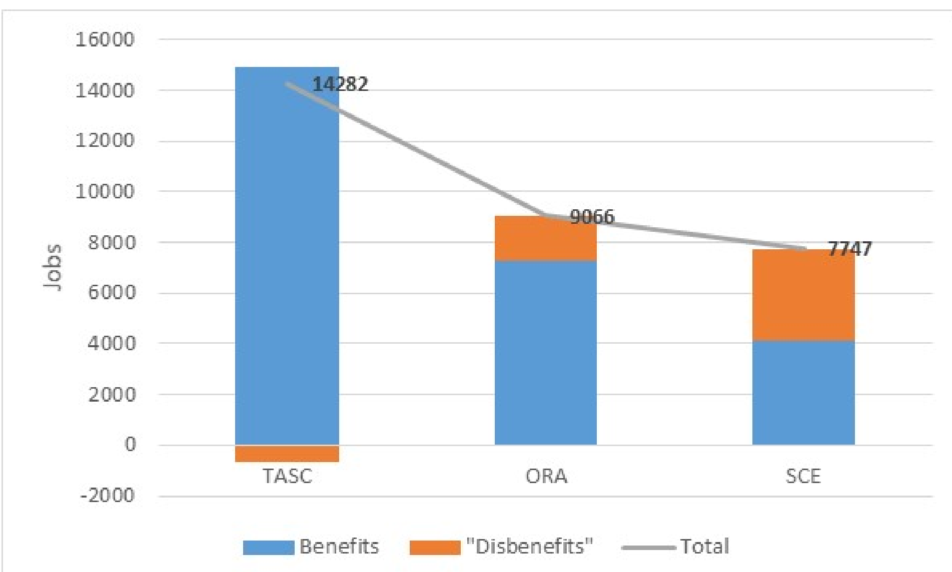
revenue shortfalls generated by participants, the cost of the program, system integration costs, and changes in utilities' avoided costs. Aspects (a) and (b) are considered benefits, while (c) would be characterized as dis-benefit.

EDR Group concludes that the TASC scenario (where NEM is continued with minor changes) provides the largest annual job impact (a gain), with approximately 14,300 California jobs created annually, and 457,300 jobs created over the 2017-2049 period studied. Maximum job creation is achieved in 2025. Exhibit ES-1 shows the average annual job impact for California by scenario, which includes direct and indirect and induced (or the *multiplier*) jobs. The TASC scenario also provides the most positive gross state product (GSP) impact, approximately $1.5 billion annually, and over $49.5 billion (in 2014$) over the 2017 – 2049 period.

These annual job and GSP impacts result from business-specific cost elasticity responses and significant multiplier effects, where job creation among California's other sectors is the result of the role of net savings to participants lowering the relative cost-of-doing business and making these sectors more competitive than they otherwise would have been, garnering more business and hence jobs. The residential segment is responsible for the largest share of job impacts because it achieves the largest share of net savings and has additional purchasing power which supports more consumer spending.

It is worth noting that the Public Tool has predicted that non-participating ratepayers under the ORA and the SCE scenarios, will actually experience rate reductions due to the scale of avoided costs (hence the "dis-benefit" isn't so, and as a result, it is a stimulating event for the state's economy).

Exhibit ES-1: Average Annual California Job Impact by Scenario



1 OVERVIEW & APPROACH

1.1 Study Objective

Focus. MRW's client, The Alliance for Solar Choice (TASC) in preparing feedback to the California Public Utilities Commission (CPUC) on the continuance of the existing NEM program sought to provide additional evidence on possible program extensions. While all stakeholders would be expected to make use of the information and diagnostics from analysis in the Public Tool, demonstrating how a proposed NEM scenario works in the 'secondary markets' may prove useful in selecting among alternatives, especially with long-lived performance of NEM systems. After all, each scenario achieves *different levels of gross bill savings and participant costs*, with *different allocations across customer-segments*, and *different non-participant ratepayer implications* again with *different allocations across customer-segments*. All scenarios are exerted to the same assumed pathway for relying on in-state business or construction trades with respect to spending to make improvements at customer-sites.

1.2 Methods

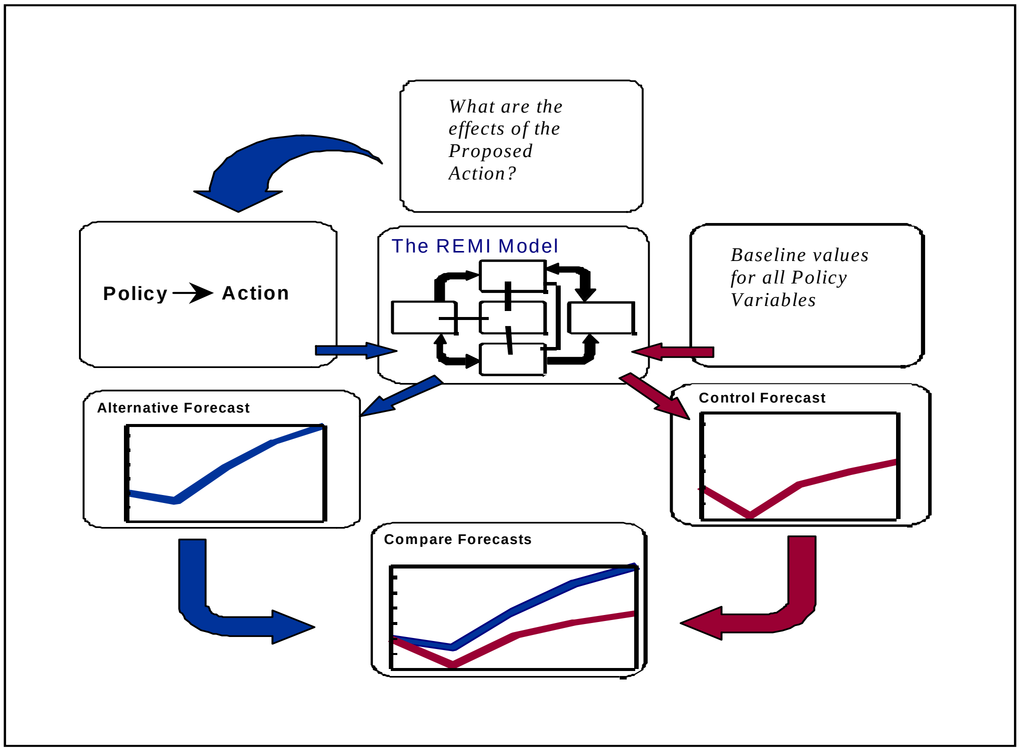
Forecasting Economic Impacts. EDR Group used an annual economic forecasting software that was 'calibrated' to depict the California economy. The source of this model is Regional Economic Models, Inc. (REMI) which has been offering this analysis tool since the early 1980's. The REMI model has long been in use by several California agencies including the South Coast Air Quality Management District (since the late 1980's), Los Angeles MTA, Southern California Association of Governments, and more recently the California Energy Commission (for ARRA evaluation related studies). We use a single-region California model with history through 2013, forecasts as far as 2060, and with 23-sectors.

The REMI model, being a dynamic (that is year-by-year), computable general equilibrium (CGE) model, was designed for conducting *"what-if"* analysis. The system can handle a wide-range of *shocks* concerning the macro economy (by use of a relevant[3] set of policy levers), and then re-solve the annual economy (through CGE adjustment imparted by its equation structure). The *shock* (a policy's direct effect) is defined as *a change from what the (lever's) concept value was in year_t without the proposed scenario* – sometimes referred to as "the base case." The base case is defined as "no additional NEM installation after 2016." The types of economic items we change for the NEM scenarios include *changes in the cost-of-doing business* by sector, *changes in household purchasing power*,

[3] Relevant to the client's scenario and its workings within the sub-market it is focused on.

change in Farm income, changes in public spending, *change in labor payments for the Construction trades*, and *change in Wholesale sector activity*[4] . Figure 1-1 portrays how the forecast of an economic impact is conducted in the REMI model. The 'compare forecasts' element in the flowchart could be describing *employment* levels under the (red) Control or base case conditions to the (blue) scenario case. The x-axis implies annual increments, the y-axis the scale of jobs. The difference between the two forecasts at any point in time defines (annual) *impact*.

Figure 1-1: Generation of Economic Impact

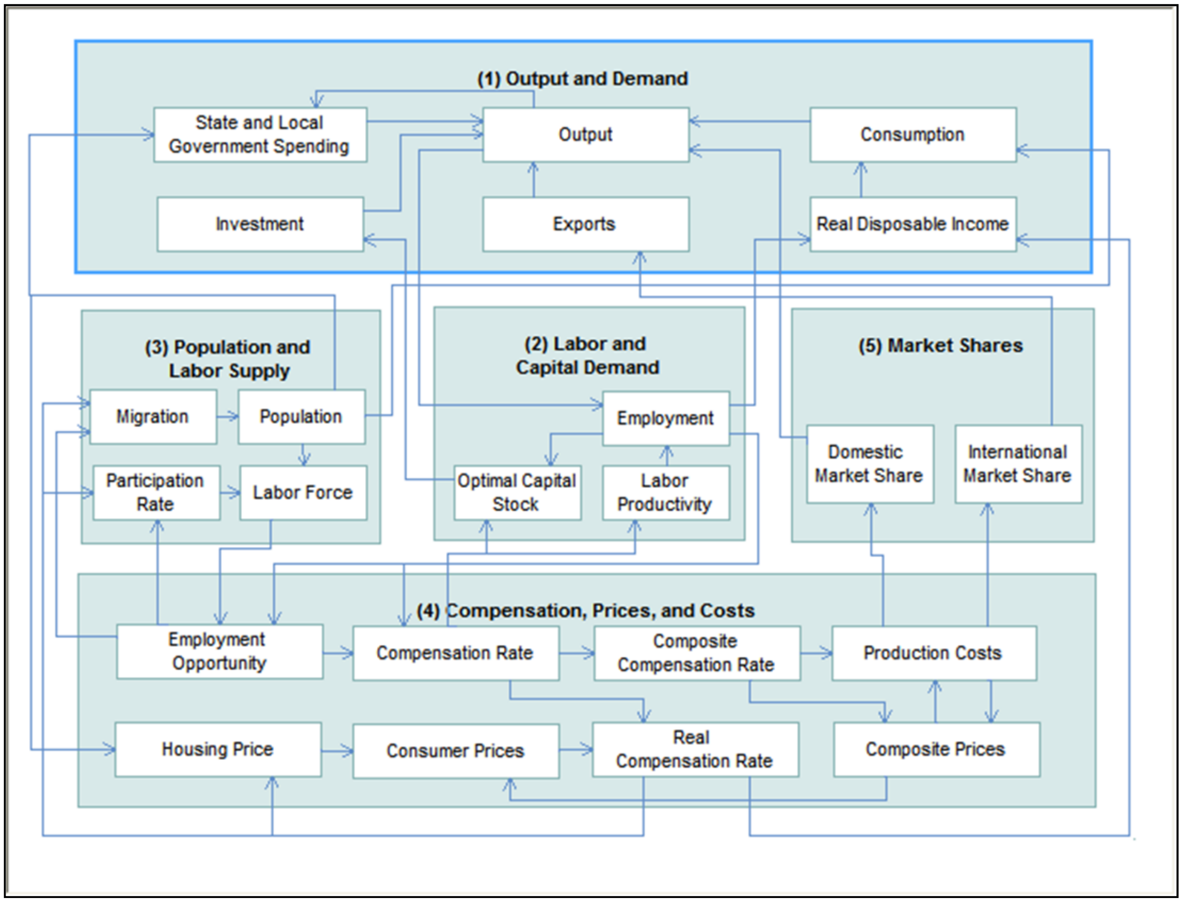


Source: Regional Economic Modeling, Inc.

Figure 1-2 provides a high-level description of the element above labeled "the REMI Model". The arrows are an indication of *simultaneous feedbacks* that exist between various markets within a regional economy. The model will *iterate* many times within an annual increment until it converges to a solution before moving onto the next year in the forecast.

[4] Not gross receipts or sales, but 'mark-up', gauged at 17 percent of equipment investment. Source: IMPLAN data for the California economy.

Figure 1-2: The Structure of the REMI regional Model



Source: Regional Economic Modeling, Inc., REMI documentation

1.3 Organization of report

Chapter 2 presents information on each scenario as derived from the CPUC Public Tool and subsequently transformed into the set of *direct effects* for the REMI model to encounter. Chapter 3 presents the REMI results for each scenario. Chapter 4 contains a brief recap of the findings.

2 THREE NET ENERGY METERING CASES

2.1 Definition of Cases

Scenarios. MRW and its client identified three alternate NEM scenarios for REMI modeling impact analysis from 2017 through 2048 to include in the study. These cases include:

- TASC's August 3, 2015 Proposal, assuming all its Public Tool modifications and a two-tiered residential rate structure. In this case, the *residential adoption accounting for 75% of gross bill savings,* and *commercial segment adoption 17% (the balance allocated to FARM, Industrial, and Municipal segments)*
- The Office of Ratepayer Advocate's (ORA's) August 3, 2015 Proposal, run using Public Tool with the modifications recommended by TASC and a two-tiered residential rate structure. In this case, the *residential adoption accounting for 53% of gross bill savings,* and *commercial segment adoption 35% (the balance allocated to FARM, Industrial, and Municipal segments)*
- Southern California Edison's (SCE's) August 3, 2015 Proposal, run using Public Tool with the modifications recommended by TASC and a two-tiered residential rate structure. In this case, the *residential adoption accounting for 62% of gross bill savings,* and *commercial segment adoption 30% (the balance allocated to FARM, Industrial, and Municipal segments)*

The percentages used in each scenario description reflect the share of cumulative nominal gross bill savings for the interval accruing to participants within a customer-segment.

2.2 Direct Economic Implications by Scenario

The direct economic implications of a scenario can provide an indication of the direction of subsequent macroeconomic change (on jobs, gross state product or any number of metrics) before introducing the information into an economic impact system. An understanding of the set of "direct effects" as derived from the Public Tool is important for (a) making sure something logical has been harnessed from the NEM analysis tool, and (b) having a 'preview' of what to expect when the policy affects the secondary markets (the non-NEM aspects of the California economy).

Participants' *net* Savings. Regardless of customer-segment, an energy customer who decides to participate in net energy metering, will be exerted to *cost of improvement*, which is defrayed in part by incentives, and a stream of *bill savings*. The difference between the participant's outlay and the bill savings is *net savings.* Table 2.1 presents these as cumulative amounts by scenario (using the nominal time-series of changes year-by-year from the Public tool).

Table 2.1 Cumulative Participant *net* Savings by Scenario

	TASC	ORA	SCE
All segments	**$30,750,973,810**	**$12,600,053,032**	**$5,283,199,534**
RESID	**$21,992,812,458**	**$3,850,004,727**	**$1,683,023,307**
COMM	**$6,413,123,948**	**$6,882,738,156**	**$3,006,422,767**
INDSTRL	**$466,362,461**	**$160,164,891**	**$99,229,508**
MUNICIP	**$874,516,902**	**$938,555,203**	**$409,966,741**
AGRIC	**$1,004,158,040**	**$768,590,054**	**$84,557,211**

Source: MRW & Associates using the Public Tool

Non- Participants' ratepayer effects. Non-participants would be expected to make up for the utilities' lost revenue from participant systems. Non-participants would also absorb the cost to administer NEM program as well as system integration costs ***less*** the utilities' avoided costs. As Table 2.2 shows only the TASC scenario has an overall rate increase, denoted by the values in the ( ), regardless of segment to account for all these elements. The other scenarios are predicted by the Public Tool to *lower rates* for non-participants in most if not all customer-segments due to the magnitude of avoided cost for the utilities. For the ORA and SCE scenarios then, these direct effects will serve to boost the California economy.

Table 2.2 Cumulative Non-Participant ratepayer cost by NEM Scenario

	TASC	ORA	SCE
All segments	**($2,069,923,899)**	**$6,458,639,782**	**$13,099,147,831**
RESID	**($1,026,445,241)**	**$7,279,783,172**	**$10,589,656,551**
COMM	**($1,444,810,633)**	**($1,265,263,162)**	**$1,523,716,321**
INDSTRL	**$227,852,527**	**$193,830,289**	**$272,807,390**
MUNICIP	**($197,019,632)**	**($172,535,886)**	**$207,779,498**
AGRIC	**$370,499,079**	**$422,825,369**	**$505,188,071**

Source: MRW & Associates using the Public Tool

Engaging California Business and Labor to deliver NEM systems. The full cost of participants' NEM improvements presents an opportunity to engage installation labor from California's resident workforce, as well as engage manufacturers or suppliers for the equipment requirements. To the extent project-related investment channels to in-state firms and construction trades, this has the potential to counter-act the temporary cost increases incurred by participants. While the Public Tool predicts the annual NEM investment as relates to a scenario's adoption rate, it cannot segment into *installation dollars* versus *equipment dollars*. Nor can it shed any indication on the *preponderance of*

California manufactured content in the NEM systems deployed. MRW and its client provided these assumptions, which are:

- Installation labor expense is 19% of project value
- The balance is equipment expense, and assumed to be 100% from Asia
- EDR Group suggested that a California *Wholesale Distribution* channel would likely be engaged to bring in imported content, in which case, a margin (or mark-up) of 17% of the equipment expense could be captured within the California economy

Table 2.3 presents the cumulative project investment amounts that are fulfilled within the state.

Table 2.3 Cumulative "California content" on Projects' Investment by NEM Scenario

	TASC	ORA	SCE
In-state "capture"	$17,023,385,650	$10,480,780,757	$7,435,731,702
Installation Labor payments	*$9,773,503,576*	*$6,017,248,879*	*$4,269,018,624*
Wholesale distributor business	*$7,249,882,074*	*$4,463,531,879*	*$3,166,713,078*

Source: MRW & Associates and TASC

The culmination of these three schedules (in tables 2.1 through 2.3) is what the economic impact forecasting model will encounter. Table 2.4 summarizes all these direct effects (with a slightly different organization). The *net* direct effect starts with net bill changes (a +) *less* the cost to make the improvements after incentives *plus* new order for California based labor and wholesale distributors. All three scenarios exhibit "+" direct effects. Looking at these "roll-ups" of savings, costs, one would expect the TASC scenario to yield the most positive macroeconomic changes for the California economy, but this will be determined at the customer-segment level as Chapter 3 presents next.

Table 2.4 Cumulative Direct effects leading into the REMI Model, by NEM Scenario

	TASC	ORA	SCE
bill changes (Participant bill savings less non-participant rate increases)	$77.3b - $2.1b = $75.2b	$41.2b - (-$6.5b) = $47.7b	$25.6.0b-(-$13b) = $38.6b
cost of systems less incentives	$51.4b - $4.8b = $46.6b	$31.6b - $3.0b = $28.6b	$22.5b - $2.1b = $20.4b
CA install & wholesale activity	$9.8b + $7.2b = $17b	$6.0 + $4.5b = $10.5b	$4.7b + $3.1b = $7.8b
net direct effect_cumulative(bil)	$45.6	$29.6	$26.0

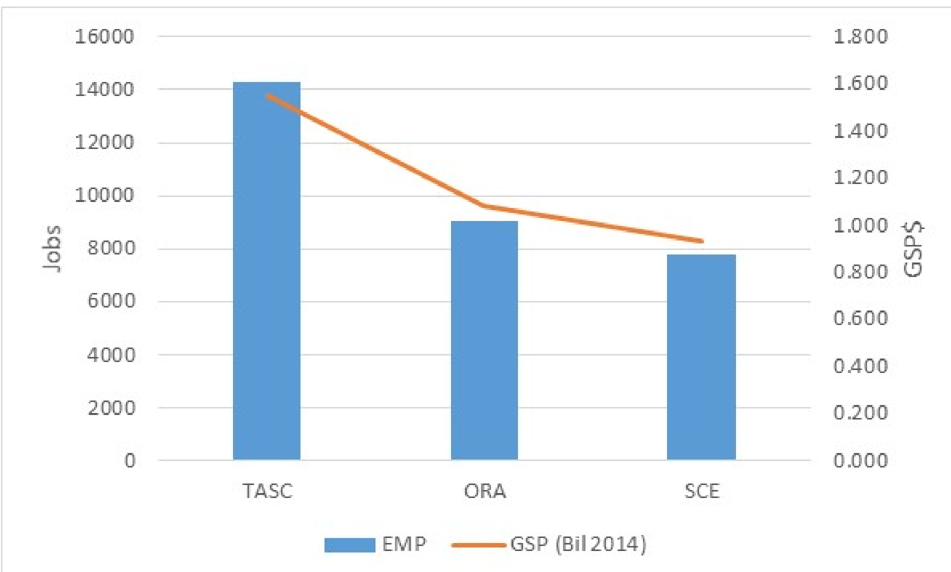
Source: MRW & Associates using the Public Tool

3 Job and Gross State Product Impacts

3.1 Impact on Select Aggregate Indicators

Average Annual Impact. California's economy will encounter a gain, in terms of employment and dollars of GSP under each scenario. Figure 3-1 presents the average annual change for each metric. The TASC NEM scenario provides the most positive annual job impact (approximately 14,300) and GSP impact (approximately $1.5 billion) followed by the ORA scenario.

Figure 3-1: Average Annual Impacts on California Economy from NEM scenarios



Source: EDR Group, Inc. and REMI PI+ Model

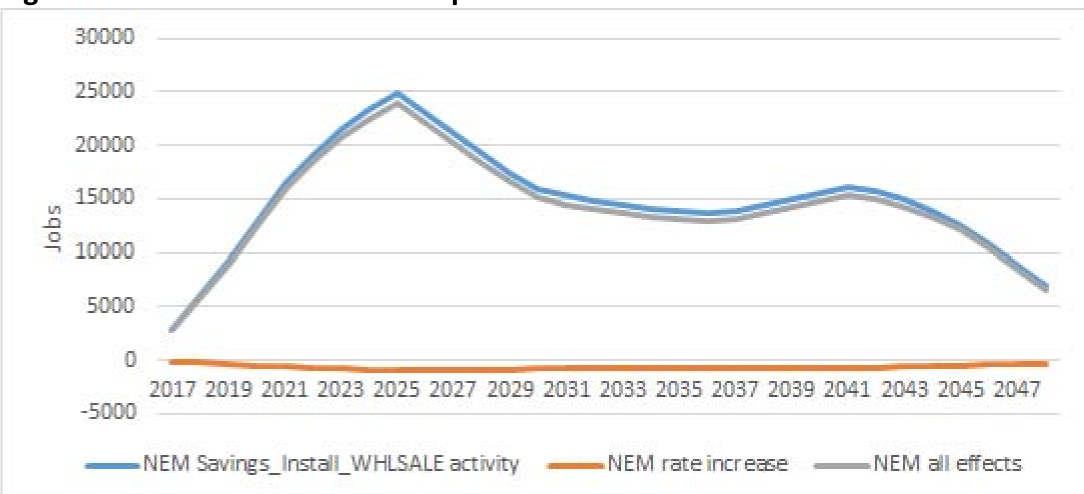
3.2 Employment Impacts over Time

Scenario Phasing elements. The REMI model encounters the timing of a scenario's direct effects (discussed as cumulative amounts in Chapter 2). In the scenario design certain temporal features emerge: incentives end between 2024 and 2028, project investment completes in 2044, annual bill savings, (and non-participant rate effects) ramp up,[5] and

[5] All scenarios appear to achieve a maximum savings benefit by 2025

persist through 2048 though with decay. Figure 3-2 shows the employment changes over time for the TASC scenario, and by two major segmentations of the direct effects, those that would be *stimulating* versus those that could be *depressive* on an economy. The grays series below denotes all effects in combination. It closely mimics the trajectory and amplitude over time that the "+" direct effects of the scenario exert on the California economy. The non-participant ratepayer effects in orange, the "-"of the direct effects exerts a small adverse influence on California jobs. The apex of job gains, in 2025, coincides with the maximum of *net savings* experienced by California's energy customers. More specifically, in 2025, the profile of gross bill savings reach the maximum while the project investment costs to participants have yet to reach the maximum.

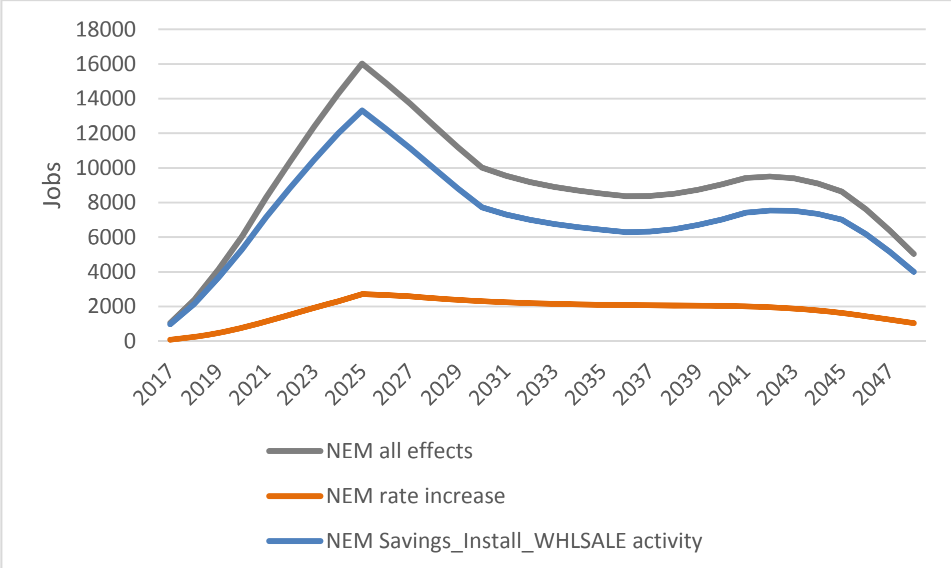
Figure 3-2: TASC NEM Scenario Impact on California Jobs



Source: EDR Group, Inc. and REMI PI+ Model

A similar presentation for ORA and SCE are shown in Figures 3-3 and 3-4 respectively. For the ORA scenario the jobs impact trajectory is higher than the impact trajectory emerging from the "+" direct effects. This is the result of the Public Tool predicting a *lower rate* environment for non-participants. Overall, however, the ORA scenario does not yield the maximum job impacts for California (note the scale on the y-axis).

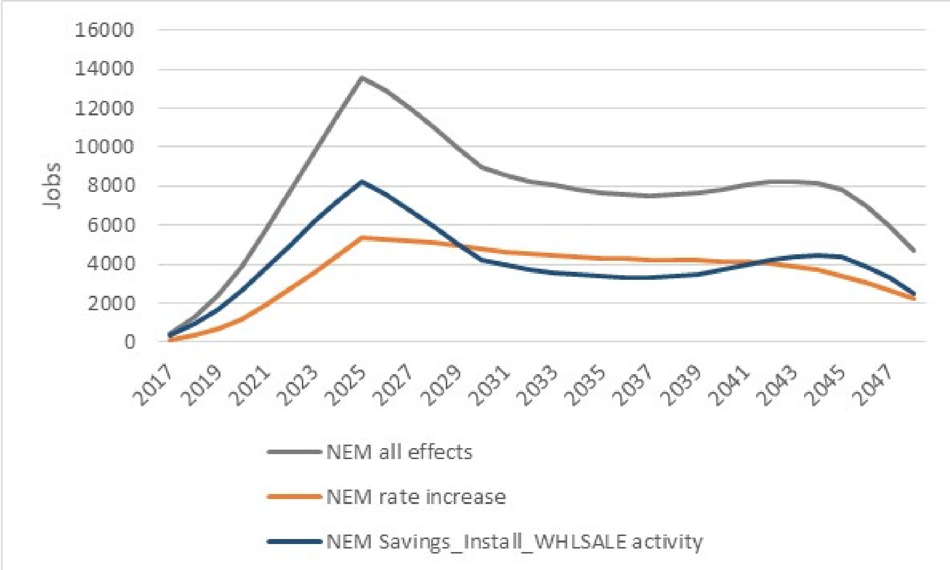
Figure 3-3: ORA NEM Scenario Impact on California Jobs



Source: EDR Group, Inc. and REMI PI+ Model

The SCE scenario job impact trajectory (all effects) is higher than the impact trajectory emerging from the "+" direct effects. This is the result of the Public Tool predicting a *lower rate* environment for non-participants based on the avoided costs to utilities. Interestingly, between 2029 and 2038, the Residential, AGRIC, and Industrial participants have net dis-savings (system costs exceed their bill savings in this interval of expired incentives). As a result, it is the rate reductions estimated by the Tool for the "non-participant rate increase" event that supports the majority of job creation between these years. The blue series still remains in positive job impact territory from the stimulating effects of installation activity for California workers and wholesale distributors making their mark-up on importing equipment for customer systems. The SCE scenario yields the smallest total job impacts for California (note the scale on the y-axis).

Figure 3-4: SCE NEM Scenario Impact on California Jobs



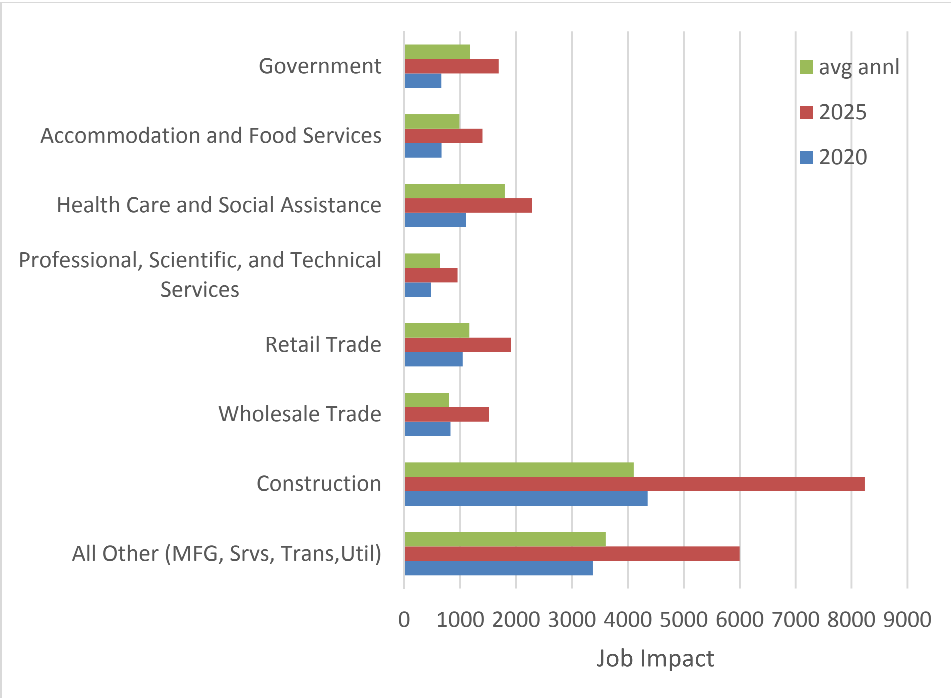
Source: EDR Group, Inc. and REMI PI+ Model

3.3 Employment Impacts by Sector

For the TASC scenario, the "all effects" employment impacts are shown in Figure 3-5 by Sector as categorized in the REMI 23-sector model. They are shown for 2025 (when bill savings achieve a maximum), for 2020, and for the annual average. The reason for this is to portray (a) the influence of the pattern of direct effects on a key part of the job impact dynamics (+ or -), and (b) if the pattern of direct benefits is changing over time, then the multiplier effects (included in the REMI solution) will also differ. The sector referred to as "All Other" captures the impacts for the balance of sectors not called out from among the 23-sector list.

Three points are worth noting. First 2025 is an apex moment for job impacts in California under this scenario. Not only is the participants' net savings at a maximum, but the maximum rate increase to non-participants has been realized, yielding the maximum on the *net (positive) ratepayer* effect, and installation contracts for California workers are at a maximum (hence the pronounced job gain for *Construction*). The 2025 *Wholesale Trade* sector job gain reflects the mark-up activity on the NEM equipment being deployed. Second, the ability to create jobs among California's other sectors is the result of (a) the role of net savings lowering the *relative* cost-of-doing business and making these sectors more competitive than they otherwise would have been, garnering more business hence jobs; and (b) even if one sector (or group of sectors, such as the Industrial segment) wasn't awarded heavy participation under the scenario (i.e. net savings), if any of their customers were, be they from the residential or commercial segments, the customer's increased purchasing power or enhanced business competitiveness will increase activity for any supplier. Such is the nature of multiplier effects. Third, the average annual job impact for almost all the sectors is more pronounced than an early year (2020) in implementation.

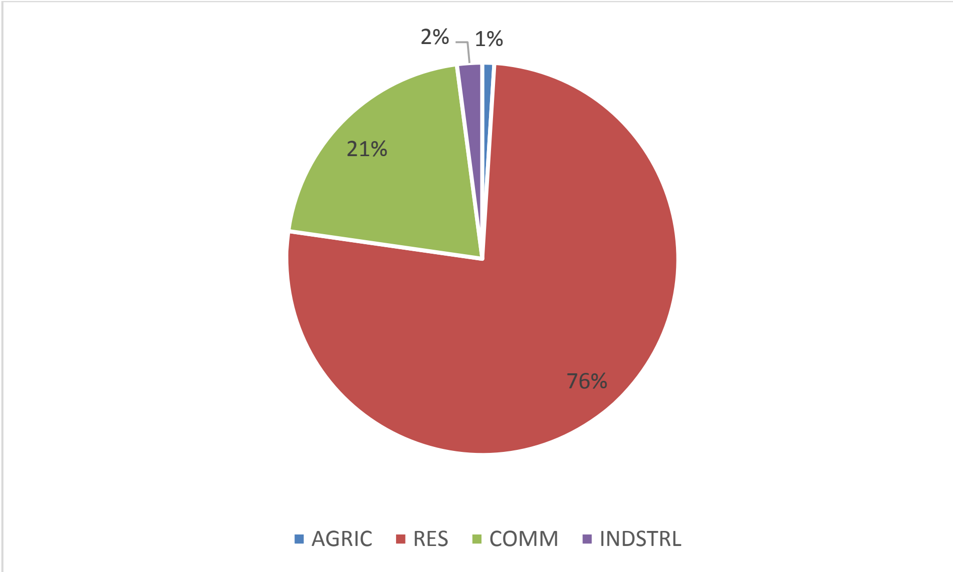
Figure 3-5: TASC NEM Scenario Employment Impacts by Sector, select Years



3.4 Employment Impacts by Customer-segment

For the TASC scenario, the employment impacts for California are contributed at different rates depending on the customer-segment that receives a dollar of *net savings*. Figure 3-6 shows that the *residential segment* is responsible for the largest share of (average annual) job impacts. This shouldn't be surprising since in Table 2.1 the residential segment has 70% of the net savings (and still has 66% after absorbing a good portion of the ratepayer effect showing in Table 2.2). However, part of this job generation results from the residential sector, having additional purchasing power which supports more consumer spending. Granted much of what households buy can be *imported* explicitly through internet purchases or shopping out-of-region, but even the local retail purchase contains a large share of non-local content. Despite all this, what consumer spending changes tend to focus on is businesses that are more labor intensive (retail, restaurants) than benefits to manufacturers that then access supply-chains typically with higher labor productivity (fewer workers but paid better) shops.

Figure 3-6: California Jobs impacts by Customer-segment, TASC NEM Scenario



4 CONCLUSIONS

Macroeconomic Observations. There should be no surprise on the resulting macroeconomic impacts when overlaying possible future NEM program designs, crafted through the Public Tool, onto an impact model such as REMI. The aspects laid out in Chapter 2 – namely an understanding of what the various “+’s” and “-‘s” are set in motion for any scenario are crucial to knowing whether a proposed alternative will ‘play out well’ in the secondary markets. The articulation of the “+’s” and “-‘s” for macroeconomic impact consideration are both different and broader than those required for a *total resource cost* version of a Cost : Benefit test.

The ORA and SCE proposed scenarios yield (through the Public Tool) *negative disbenefits* (that makes it a benefit) for the non-participant rate increases which may plausibly be attributed to the size of utilities’ expected avoided costs. The TASC scenario leads to the most positive job impacts (+14,300 average annual) and dollars of gross state product impacts ($1.5 billion) over the 2017 to 2028 interval.