Application of Nevada Power Company d/b/a NV Energy and

Application of Sierra Pacific Power Company d/b/a NV Energy

for Approval of a Cost of Service Study and

Net Metering Tariffs

DOCKET Nos. 15-07041 and 15-07042

PREPARED DIRECT TESTIMONY OF R. THOMAS BEACH, CROSSBORDER ENERGY

ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE (TASC)

October 27, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2. Please describe Crossborder Energy.

A2. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm's practice focuses on the energy markets in California, the western U.S., Canada, and Mexico. Over the last 25 years, Crossborder Energy has developed particular expertise on issues concerning independent power generation, renewable energy development, and distributed generation.

Q3: Please describe your experience and qualifications.

A3: My experience and qualifications are described in my *curriculum vitae*, which is **Exhibit RTB-1** to this testimony. My CV includes a list of the testimony that I have sponsored before this Commission, and lists the testimony that I have submitted in past proceedings before other state public utility commissions in California, Colorado, Idaho, Minnesota, New Mexico, North Carolina, Oregon, South Carolina, Vermont, and Virginia. This experience includes extensive testimony on rate design issues related to solar distributed generation (DG). For example, over the last ten years, I have filed testimony on behalf of the Solar Energy Industries Association (SEIA) or its predecessor, the Solar Alliance, in the rate design phases of each of the three major California investor-owned utilities' (IOUs) general rate cases before the California Public Utilities Commission (CPUC), as well as testimony in the CPUC's comprehensive rulemaking on residential rate design. All of this testimony has addressed rate design and cost allocation issues of concern to the solar industry and other providers of DG. In the fall of 2006, PV Now (a predecessor of SEIA and the Solar Alliance) retained me to coordinate the solar industry's participation in an intensive, CPUC-sponsored process to develop the Handbook with the program and process details for the California Solar Initiative (CSI), California's state incentive program for rooftop solar. In Nevada, I participated as the solar industry's representative on the stakeholder committee that provided input to the Commission on its 2014 Net Energy Metering Study. Finally, I am the owner of a 2.4 kW photovoltaic (PV) system that has been installed on my family's home in Kensington, California since January 2003. We are interconnected to the Pacific Gas & Electric (PG&E) system as a net energy metering customer (NEM) under PG&E's E-7 time-of-use (TOU) tariff. Our PV system has provided most of my family's electrical requirements for the last 12 years.

Q4. Have you previously testified as an expert witness?

A4. Yes.

Q5: On whose behalf is this testimony being offered?

A5: This testimony is submitted on behalf of The Alliance for Solar Choice (TASC).

Q6: What is the purpose of this testimony?

A6: This testimony presents TASC's rate design and ratemaking recommendations concerning the tariff that should govern customers in Nevada who install distributed solar generation above the statutory cap. This testimony accompanies the policy testimony of Tim Woolf of Synapse Energy Economics, the cost-of-service testimony of Bill Monsen of MRW Associates, and the testimony of Tom McDermott of MelTran, Inc. on transmission and distribution (T&D) issues.

II. NVE'S NEM2 PROPOSAL WOULD DESTROY THE MARKET FOR SOLAR DISTRIBUTED GENERATION IN NEVADA

A. SB 374's Policy Goals for Continued Growth of Renewable DG

Q7: Please describe the statutory standards that SB 374 set for the new NEM tariff.

A7: In passing SB 374, the Legislature reaffirmed that the purposes of NEM in Nevada are to do the following:

1. Encourage private investment in renewable energy resources;
2. Stimulate the economic growth of this State;
3. Enhance the continued diversification of the energy resources used in this State; and
4. Streamline the process for customers of a utility to apply for and install net metering systems.[1]

These goals clearly indicate that the Legislature intended for renewable DG to continue to grow as a viable energy resource for the state, and for customers to have DG as a reasonable choice to provide for a portion of their electricity needs.[2] Unless DG remains

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[1] BDR 58-800 (as enrolled), Sec. 2.8; 2015 Leg., 78th Sess. (Nev. 2015).

[2] This is consistent with the legislative purpose set forth in NRS 701B.190 that pertains to the Solar Energy Systems Incentive Program, wherein the Legislature found and declared that it is the policy of this State to "expand and accelerate the development of solar distributed generation systems in this State"; and "establish a sustainable and self-sufficient solar renewable energy industry in this State in which solar energy systems are a viable mainstream alternative for homes, businesses and other public entities."

economically viable, customers will not make private investments in DG, the DG industry will not contribute to the state's economic growth, and this opportunity to diversify the state's energy resources with clean, local, distributed solar generation will be lost.

B. Bill Savings from Solar DG

Q8: Please describe how NV Energy's proposed NEM2 rates would impact the economics of an average solar DG system in Nevada.

A8: Nevada Power Company (NPC) d/b/a NV Energy and Sierra Pacific Power Company (SPP) d/b/a NV Energy (NVE or the Company) propose to impose a demand charge that is measured based on the maximum kW demand in a 15-minute interval over the billing period. Solar customers will not be able to avoid the demand charges to the same extent as the current volumetric rates, as NVE's analysis shows.[3] Because NVE's proposed NEM2 rates move significant costs from volumetric energy rates to demand charges, the energy rates assessed under NVE's NEM2 rates are approximately 60% to 65% of what they would be for existing NEM customers (NEM1), which results in a dramatic loss of bill savings. NV Energy's own analysis of the lost bill savings that will occur under the utility's proposal, with which TASC does not disagree, shows a very substantial loss for solar customers. According to NV Energy, the bill savings available to residential solar customers in Nevada would be reduced by 32% to 40%, from about $0.10 - $0.11 per kWh to $0.06 - $0.07 per kWh, as shown in the **Table 1** below.

Table 1: *Bill Savings for the Average Residential Solar Customer*[4]

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[3] NV Energy's analyses show demand charge reductions of less than 10% for NPC residential customers, and of 20% for SPC residential loads. See NPC and SPP Narratives, Tables C-1.

[4] From Nevada Power Company d/b/a NV Energy ("NPC") Narrative, Table C-1 and supporting workpapers; Sierra Pacific Power Company ("SPP") Narrative, Table C-1 and supporting workpapers.

Utility	Metric	Current Rates		NVE NEM2 Rates	
		RS, D-1	**TOU**	**RS-NEM, D-1-NEM**	**TOU**
NPC	*Annual $*	$1,181	$1,205	$740	$725
	$ per kWh	$0.107	$0.110	$0.067	$0.066
	% change			**-37%**	**-40%**
SPP	*Annual $*	$891	$893	$609	$598
	$ per kWh	$.095	$.095	$.065	$.064
	% change			**-32%**	**-33%**

The bill savings from solar must offset the cost of the solar system, with a reasonable payback, if solar DG is to be a viable and reasonable investment for the customer. Most important, I agree with the utility's admission that the lower bill savings under its proposed NEM2 rates would no longer support the cost of a residential solar system.[5] If the solar market in Nevada is to continue to grow, then solar customers should have a reasonable opportunity to achieve a total electric bill (including both payments to the solar vendor and the remaining utility bill) that is at or below the bill for utility service without solar. Otherwise, the solar market will contract significantly because customers will no longer adopt solar to save money, which today is a major driver of solar adoption. As I will discuss, such a contraction is exactly what has happened in Salt River Project's service territory in Arizona, once that major Arizona utility adopted a rate structure very similar to NVE's NEM2 proposal.

[5] See NPC Narrative, Vol. 2., p. 4; SPP Narrative, Vol. 2., p. 4.

C. Impact of Residential and Small Commercial Demand Charges

Q9: NVE's proposed NEM2 rates feature a large demand charge and correspondingly smaller volumetric rates. Is the proposed demand charge likely to be confusing to residential customers who are considering installing DG?

A9: Yes. Demand charges are the centerpiece of the complex NEM2 rate design that NV Energy has proposed. Demand charges will confuse customers, and present a significant barrier to continued adoption of solar DG in Nevada. The potential for confusion is high, for the following reasons:

- **Customers do not understand demand charges.** To my knowledge, demand charges have never been part of residential rate design in Nevada, and are very rare for residential customers elsewhere in the U.S. Residential consumers have experience with their energy use, in kilowatt-hours, because that is the basis on which they have been billed in the past. They do not have experience with the concept of demand, measured in kW, which is the rate at which a customer uses energy as a function of time. In mathematical terms, it is the first derivative of energy use with respect to time.

  Customer surveys conducted by other electric utilities in the western U.S. confirm that demand charges would be confusing. In 2013, the three major investor-owned electric utilities in California commissioned a customer survey as part of the CPUC's comprehensive rulemaking proceeding on residential rate design.[6] This study concluded that a demand charge "was confusing" to participants, who ended up making inaccurate comparisons to a fixed monthly service fee because they failed to comprehend that a demand charge "varies based on kW demand levels."[7] As

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[6] CPUC Docket No. R. 12-06-013.

[7] Hiner and Partners, Inc. *"RROIR" Customer Survey*, April 16, 2013, p. 22. In the CPUC's rulemaking proceeding on residential rate design, only one utility, San Diego Gas & Electric (SDG&E), proposed anything like a residential demand charge. SDG&E proposed an optional rate with a "demand differentiated fixed charge," a schedule of three increasing levels of monthly fixed charges, with the applicable fixed charge based on the customer's maximum kW demand in the prior month. Such a

another example, earlier this year, San Diego Gas & Electric (SDG&E) conducted a survey of customer preferences for a new NEM tariff in California. This survey only looked at possible new structures for a NEM tariff, and did not include a continuation of the current NEM tariff based on a retail rate credit. The possible new NEM structures that SDG&E tested included (1) a feed-in tariff with a set price for all DG output, (2) a demand charge similar to NVE's NEM2 structure, and (3) an installed capacity charge similar to the $ per installed kW of DG capacity used by Arizona Public Service. Significantly, the simplest structure, the feed-in tariff, although not as simple as current NEM1, was favored over demand charges or installed capacity charges by wide margins – by 4-to-1 over a demand charge and by 5-to-1 over an installed capacity charge. The detailed survey results are included in Exhibit RTB-2 to this testimony. The survey concluded that for customers the key drawbacks of the demand charge are that it is "confusing," "unpredictable (may pay more)," and "can be difficult to change behavior" to reduce their maximum 15-minute demand.[8]

- Such confusion is not surprising, given that **demand data for typical home energy uses** is not readily available. Energy usage data for home appliances is typically expressed in term of the annual kWhs of energy use, for example, as in Energy Star ratings for appliances.[9] Ratings are not given in terms of the maximum power use, in kW. As a result, consumers do not have accurate information today to make intelligent decisions to reduce their maximum kW demand.

- Indeed, **data on each residential customer's maximum hourly demand for their home as a whole only became available recently**, with the advent of smart meter

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proposal would not be as complex as NVE's proposal, which involves a standard industrial demand charge based directly on a customer's maximum kW demand in any 15-minute period of the month. The California commission rejected the SDG&E proposal, even for inclusion in California's pilot programs on new residential rate designs, as beyond the present scope of residential rate design and as potentially distracting from the CPUC's central focus on expanding the use of time-of-use (TOU) rates. See CPUC Decision No. 15-07-001 (issued July 3, 2015), at pp. 182-184 and Finding of Fact 160.

[8] Hiner & Partners, *Final Report: Solar (NEM) Rate Preferences Survey Results* (June 2015), at Slide 8.

[9] See the NVE website, at https://www.nvenergy.com/home/saveenergy/energylibrary.cfm.

data. To my knowledge, residential customers in Nevada are not informed what their maximum 15-minute demand is today or when it occurs. NV Energy's on-line data for residential customers does not track or display a customer's maximum 15-minute demand for the current billing month.[10] Indeed, there is no reason to do so, given that residential customers have never been billed on the basis of their maximum kW of demand. NV Energy's September 15, 2015 comments on rate design in Docket No. 15-03010, at page 9, admit that "since these [residential] rate classes do not have demand charges, the class level maximum kW billing determinant information is not currently measured, calculated, or recorded in NV Energy's billing system." As a result, real-time data is not readily available to residential customers about their real-time demand or about what their maximum demand has been thus far in a billing period; such real-time information would be essential if customers are to take actions to reduce their current demand. Even if, at some time in the future, such data becomes widely available through new technology, it is unlikely that customers will be able easily to alter their behavior so as to impact the level of their maximum kW of demand, which only occurs in one 15-minute period each month.

- **No education of residential customers on their kW of demand, or on demand charges, has occurred, and no details on such outreach are included in the applications.** If the Commission were to adopt a residential demand charge as part of NEM2 rates, NVE also would need to undertake a comprehensive education program on the demand charges that would apply to a customer who installs solar. As noted above, customers find the concept of demand charges confusing. I am not aware of any customer education to date from NVE on what a kW of demand means, how to determine maximum demand from smart meter data, or how maximum demand charges work. My review of the scope of the "free workshops" on solar that NVE now offers indicates that the complexities of demand charges or of the proposed NEM2 rates are not covered in these sessions. The utilities' applications promise to develop and implement "education plans" to inform customers about the new NEM2 rate structure and to develop new application materials describing the new rates,[11] but no details about the scope, content, cost, or timing of those plans or application materials have been provided.

- **Modeling of customer savings from solar under a demand-charge structure would be much more complex**, and would require data on both the hourly solar

[10] NV Energy's on-line system for residential customers displays only one day at a time of 15-minute data. Thus, a customer who wishes to track his maximum 15-minute demand for the billing period would have to scroll back through all prior days of the billing period, while keeping a running tally of the maximum demand for the month. Alternatively, a customer could download the data for the month into a text file, then import the data into a spreadsheet format such as Excel, in which the maximum value could be calculated. In my opinion, very few residential customers will have the time, inclination, knowledge, or expertise to undertake such an effort on a regular basis.

[11] NPC Narrative, Vol. 2., p. 18; SPP Narrative, Vol. 2., p. 18.

> generation and the customer's hourly load profile, in order to calculate the impacts of the new demand charges. Today, the solar sales process can use monthly usage data, for example, from the paper bills from the last year of the potential customer's utility service. Obtaining hourly smart meter data will be significantly more complex, as will the analysis to predict customer bill savings. Obviously, the software exists to perform these more complex calculations, but the customer is unlikely to be able to verify the math and may have much greater difficulty understanding and trusting the salesperson's estimate. This will significantly complicate the solar sales process and negatively impact the sustainability of the solar industry in Nevada.

The very complex rate structures that NV Energy would impose on residential DG customers might be appropriate for large commercial, industrial and institutional facilities, who understand both their TOU energy usage and their maximum monthly demand, have the metering to track both energy use and demand in real time, and who can pay facility managers dedicated to managing those demands and costs. But such a structure is not understandable or workable for residential or small commercial customers who spend only a few minutes a month focused on their utility bills.[12] NV Energy's lead policy witness, Dr. Faruqui, admitted that he "has not conducted or reviewed an analysis of how residential customers are likely to respond to the price signals from the NV Energy utilities' three-part rate proposal for NEM 2 customers."[13] Imposition of such a rate structure on NEM customers will implement a major barrier to the adoption of behind-the-meter DG and will not contribute to the sustainable growth of customer-sited renewable DG, as required by Nevada's NEM statute.

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[12] This is consistent with the regulations that govern rate design based on marginal cost of service in Nevada. See NAC 704.662(1)(c)(2) which states that rates "charged by the utility for supplying electricity to customers of a particular class must reflect the marginal (incremental) cost of serving that class…unless the Commission determines, in a proceeding to establish or change the rate, that…the expected level of understanding or acceptance of the rate by the customers of the class to which the rate would apply is such that the rate would not likely serve the purpose of this regulation."

[13] See Exhibit RTB-3 to this testimony, NV Energy's response to TASC Data Request (DR) 86.

Q10: Is the simplicity and understandability of the existing NEM structure a significant benefit to customers, the utility, and the Commission?

A10: Yes, it is. The simplicity and understandability of NEM for the customer is a major reason why it is now used in 44 states.[14] It is important for the Commission to recognize that, under net metering as it exists today, a customer who installs a DG system will continue to see, on the margin, exactly the same rate design signals that the customer would see if he or she were a non-NEM customer. This is true regardless of whether the solar customer is importing or exporting power at any moment.[15]

Thus, under the current structure of NEM, all DG customers continue to see exactly the same price signals from rate design as non-NEM customers. This "transparency" of the price signals under NEM is a strong reason to continue the present structure of NEM. Customers find it easy to understand that the same signals which they receive under the regular rate design will continue unchanged if they install a NEM system. This also means that the utilities, the solar industry, and the Commission do not have to educate NEM customers about rate design in any way that is different than with non-NEM customers. For example, if Nevada were to decide to encourage more customers to adopt TOU or Critical Peak Pricing rates, informing customers about these new rate structures will be the same regardless of whether the customer has a NEM system or not.

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[14] See http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/04/Net-Metering-Policies.pdf.

[15] For example, at my home I take service as a NEM customer under PG&E's E-7 residential TOU rate, which has two pricing periods, on-peak and off-peak. If I consume power from the PG&E system during the summer on-peak period of noon to 6 p.m., I pay for that power at the high E-7 on-peak rate. My west-facing PV system at times produces more power than my home consumes during PG&E's on-peak period, and I export this power back to PG&E, which the utility then uses to serve my neighbors and for which I receive a credit at the full E-7 on-peak rate. Yet even when my system is exporting, I retain a strong incentive to shift any available loads out of the on-peak period – if I do not run appliances between noon and 6 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at the E-7 on-peak rate. This is no different than the price signal I face when I am importing on-peak power. In the mornings, evenings, and on weekends, I pay the much lower E-7 off-peak rate when I run appliances, and I also earn lower NEM credits for exports during these off-peak hours. Thus, even as a solar customer, I continue to see exactly the same TOU price signal as non-solar customers on the E-7 rate, and I continue to have the same incentive to shift my loads to off-peak periods.

D. The Proposed Demand Charges Are Not Cost-Based.

Q11: Is it cost-based to design rates for residential and small commercial solar customers that include a large demand charge to cover capacity-related generation, transmission, and distribution costs?

A11: No, it is not. When customers install solar DG systems, the customers serve a significant portion of their load with their own on-site generation. This reduces the utility's costs to serve the DG customers and provides new renewable capacity to the grid. However, if a significant portion of the utility's costs are collected through a demand charge, the customers may see little reduction in their bills for the costs covered by the demand charge. This relatively small change in their bills may fail to compensate solar customers for the capacity-related costs that their on-site generation avoids. For example, a cloudy, low-demand day with low PV output may be the day that causes solar customers to incur a significant demand charge for the entire month, but the resulting monthly bill will fail to recognize that the same customer contributed significant peaking capacity on the hot, sunny, high demand days of that same month (and thus avoided significant capacity-related costs which are not recognized in the solar customer's bills).

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Q12: Can you show that this over-recovery of costs from solar customers will happen under NV Energy's proposed NEM2 rates?

A12: Yes. NVE has assembled hourly profiles of total (gross) load, delivered load, and generation for an average residential solar customer, and has used these profiles to calculate monthly cost of service and bills for the average solar customer under both NEM1 and its proposed NEM2 rates. The data for NEM2 rates with a large demand charge, shows that, for NPC, the monthly maximum demand for the average residential solar customer drops by only 8% on an annual basis, and by just 9% during the four summer peak months (June-September), after the customer installs solar.[16] Thus, for the capacity-related costs included in the NEM2 demand charge, solar customers will only be able to reduce their bills by 8% if they pay a demand charge applicable in all months (the RS-NEM rate), and by 9% if the demand charge principally applies just during the four summer months (the ORS-TOU-NEM rate). In contrast, if the same capacity-related costs are recovered through a volumetric rate (as in the present RS rate), the average solar customer would reduce his bill by 36% based on the difference between pre-solar total loads and post-solar delivered volumes.[17]

To see whether a demand charge or volumetric charge is more cost-based for the solar customers, we compared these bill reductions under both demand and volumetric charges to the amount by which the average solar customer will be able to reduce the utilities' capacity-related generation and T&D costs, using the utilities' hourly marginal costs. The NV Energy utilities allocate their marginal capacity costs to hours using the LOLP (generation) and POP (T&D) factors. Based on the hourly profile of marginal costs, the average NPC solar customer will reduce the utility's generation capacity costs by 42% and their T&D capacity costs by 45%. A volumetric rate will come the closest to covering these cost reductions, by allowing the solar customer to reduce his or her bill by 36%, while a demand charge will allow the solar customer to avoid only 8% of these costs. Thus, we conclude that a demand charge structure will undercompensate the average solar customer, allowing the customer to reduce his bill by less than one-fifth of the amount of capacity-related costs that the customer allows the utility to avoid, whereas

[16] See NPC Narrative, Vol. 2., Table C-1.

[17] Based on the reduction of 36% in the average NEM customer's post-solar delivered load (11,662 kWh/year) compared to the pre-solar total customer load (18,117 kWh/year), from NPC Narrative, Vol. 2., Table C-1.

a volumetric rate would allow the solar customer to reduce his bill by more than 80% of the amount by which the utility's costs are reduced. Thus, a volumetric rate is the more cost-based rate structure for residential solar customers in Nevada. The following table summarizes these results for the average residential solar customer, for both NPC and SPP.

Table 2: *Demand Charge Undercompensates the Average Solar Customer*

Utility	Bill Reduction from Solar		Cost Reduction from Solar	
	Demand Charge	Volumetric Charge	Marginal Generation (LOLP)	Marginal T&D (POP)
NPC	-8%	-36%	-42%	-45%
SPP	-14%	-34%	-46%	-53%

The following **Figure 1** illustrates this point graphically. The figure shows the total and delivered loads of the average solar customer in the four summer months (June – September). Virtually all of the probability of peak (POP), and thus almost all of the hourly T&D marginal costs, occur during the summer months. The difference between the total and delivered profiles is the amount of DG output that serves the customer's load. The figure also shows the hourly profile of T&D marginal costs (POPs) over these days. The figure makes clear that the hours with the highest T&D marginal costs (2 p.m. to 7 p.m.) occur when there is significant solar output and when the solar customer serves a significant portion of its load with its own generation. The POP-weighted reduction in the marginal T&D costs provided by the average solar customer on these peak days is 45%. Yet due to the demand charge in NV Energy's NEM2 rates, if this customer were charged those rates, it would be able to reduce the demand charge portion of its bill by no more than 8%.[18] Thus, a demand charge structure is not cost-based; a volumetric rate

[18] In Figure 1, it appears that the reduction in the average solar customer's non-coincident demand on these days is greater than 10%, and might be as high as 15%. However, because the demand charge is set

would be a far more accurate and cost-based way to recover the costs to serve solar customers.

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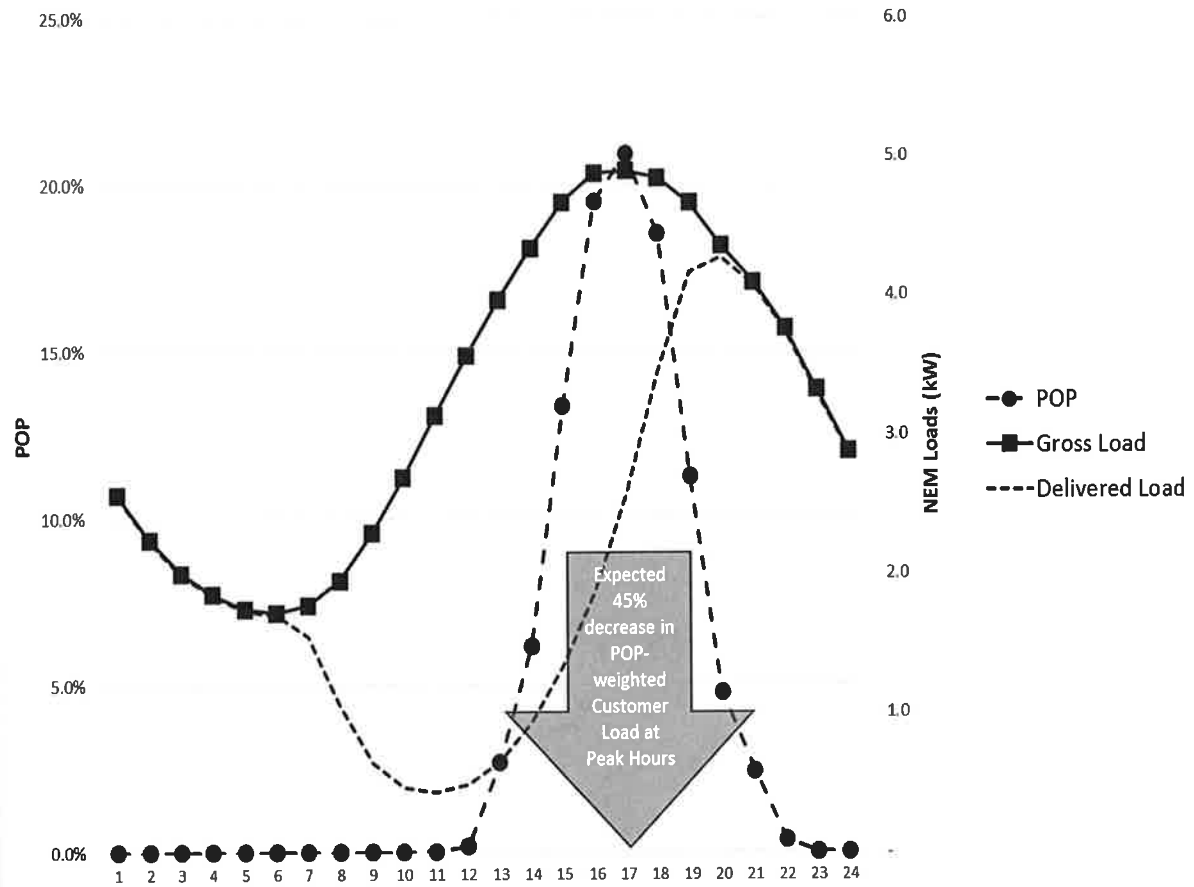
Figure 1: *NEM and POP Profiles on Expected Peak Load Days*

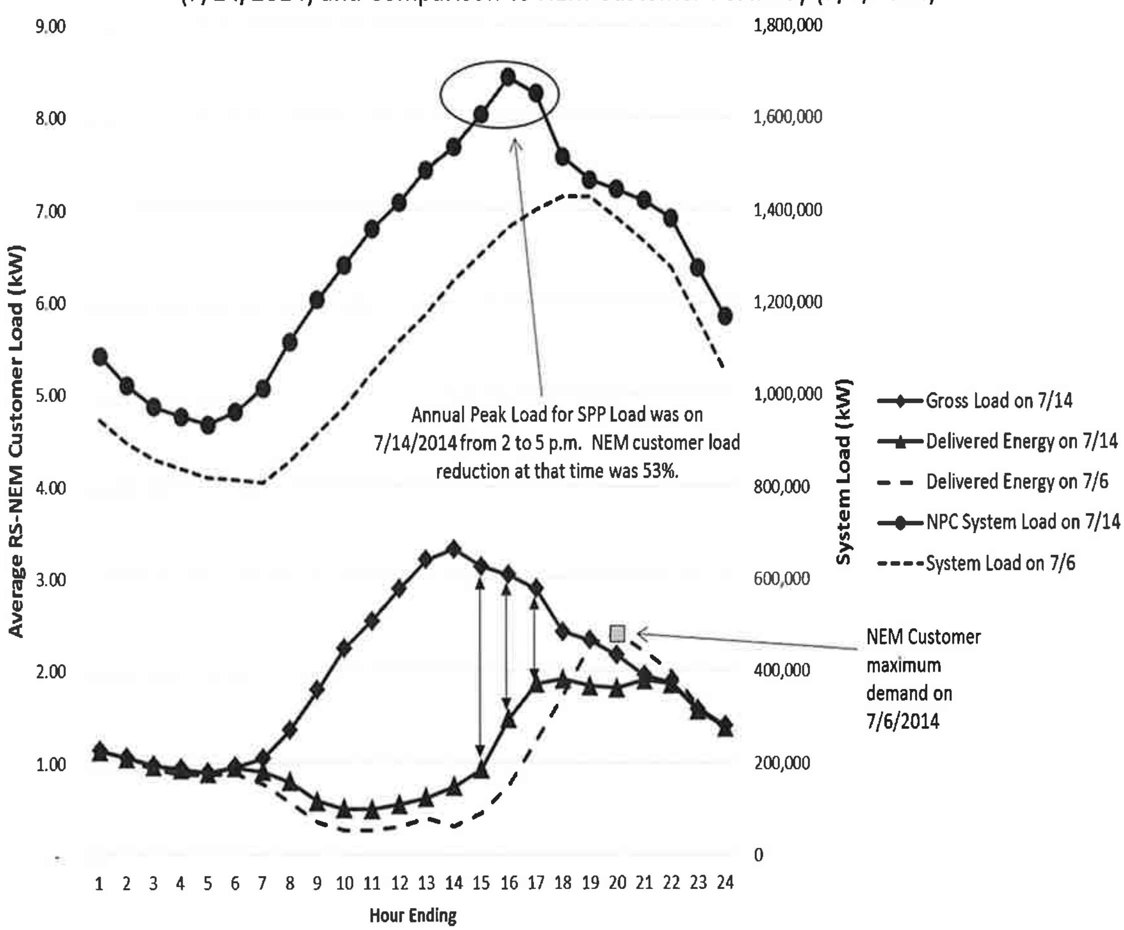


The following **Figure 2** tells the same story, but focuses only on two days in July 2014. July 14 was the peak day on the SPP system in 2014, with demand peaking in the hour

based on the maximum 15-minute usage on any day and at any time, the day with the maximum 15-minute usage for the month could occur, and probably did occur, on one of the days that is not in the 40 days with the highest marginal T&D costs (the 40 top POP days). Thus, the demand charge structure fails to bill the solar customer for his usage on the high-demand days that really matter in terms of driving system costs.

ending 4 p.m. On that day, NEM customers provided a 53% reduction in their demand on the SPP system in the three peak hours (2 p.m. to 5 p.m. – see circled hours in figure) when the SPP system was most stressed. On that peak day, the average demand of the NEM customers on the system did not exceed 1.9 kW. However, if NEM customers had been billed under a demand charge as NVE proposes, in July 2014 they would have been billed for an average demand of 2.4 kW, a demand level which NEM customers reached on a different day, July 6. July 6 was a day with a significantly lower system peak demand (1,430 MW) than on July 14 (1,689 MW). With a demand charge, NEM customers would be billed for 25% more demand than what they imposed on the system on the peak day in that month. Thus, a demand charge would be inaccurate and not a cost-based way to bill NEM customers for the actual demands they impose on the system.

Figure 2: NEM Customer Load on SPP 2014 Peak Load Date (7/14/2014) and Comparison to NEM Customer Peak Day (7/6/2014)



The following **Figures 3 and 4** extend this analysis to all months covered by NVE's data for residential NEM customers and to both utilities. The figures compare the maximum 15-minute, noncoincident demands of residential NEM customers to their demand in the coincident system peak hour in each month, based on delivered loads. They show clearly that noncoincident demand charges that include significant peak-related costs will overcharge NEM customers for the actual capacity-related costs which they cause, particularly during the summer months when the probability of peak (POP) is the highest.

Figure 3: Concident vs. Noncoincident Peak Delivered Load
NPC Residential (RS) NEM Customers
(June 2014 to May 2015)

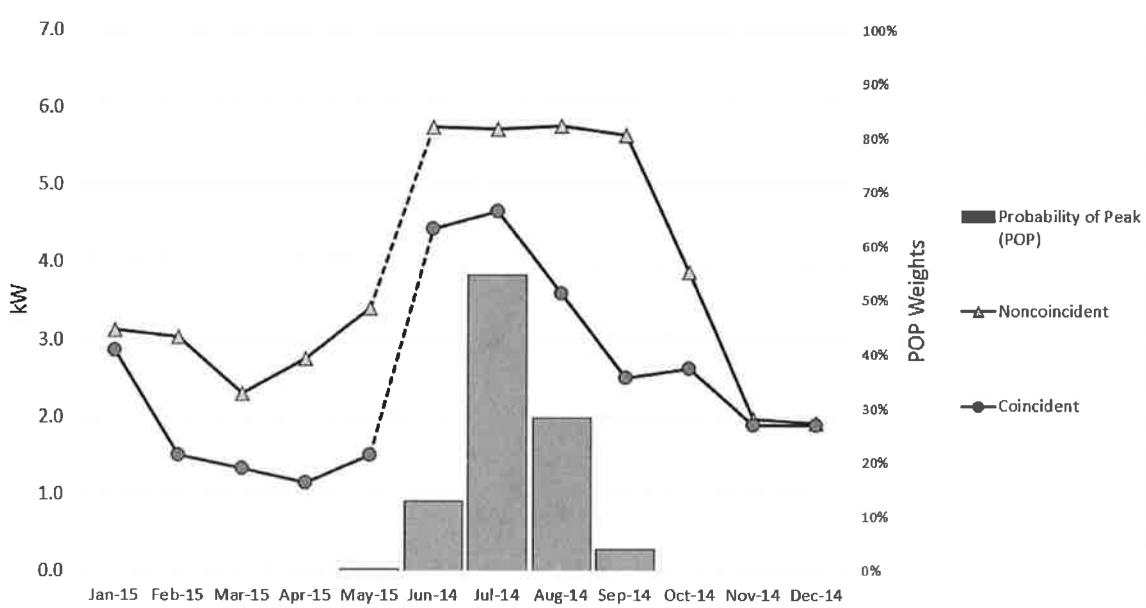
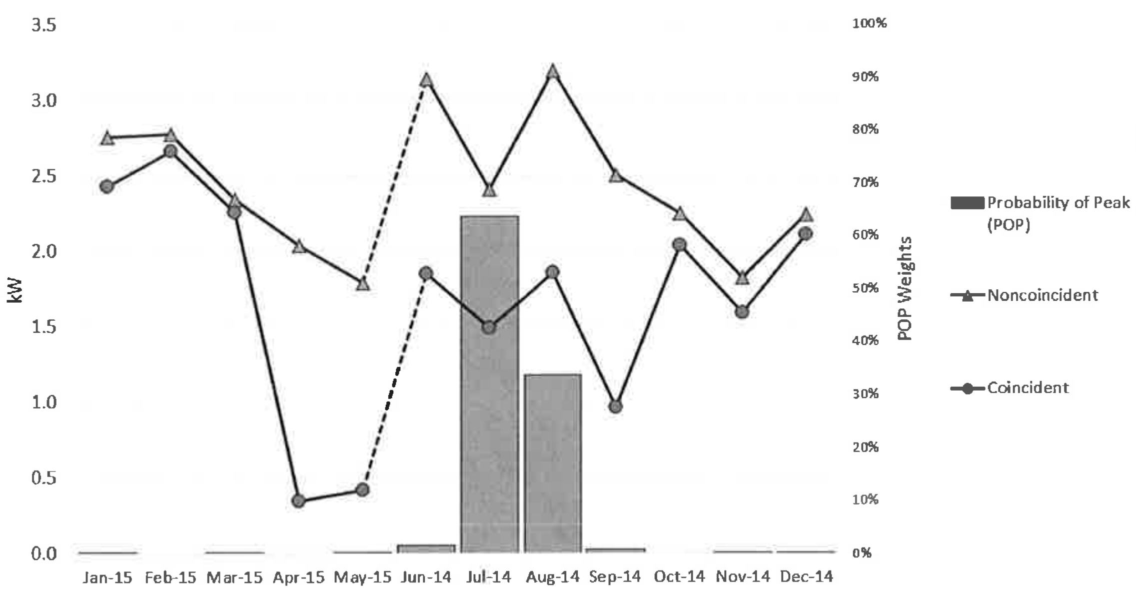


Figure 4: Coincident vs. Noncoincident Peak Delivered Load
SPP Residential (D-1) NEM Customers
(June 2014 to May 2015)



Q13: Is it cost-based to assess a demand charge on residential customers based on the customer's maximum use in any hour?

A13: No, it is not. First, the charts in NV Energy's narrative, as well as Figures 1-4 above, show clearly that the marginal capacity-related costs which the utilities would include in the demand charge are focused on the afternoon and early evening hours, not morning or nighttime hours. As a result, it is not reasonable to impose a demand charge on residential customers based on their maximum demand in any hour. Such maximum demands may occur outside of the hours that drive the utilities' marginal costs. For example, a residential customer could hit a monthly peak demand in the morning getting ready for work and school at a time when demand is low on both the local distribution system and the overall NV Energy system. The load of a single residential customer is far too small to have any appreciable impact on local and system capacity.

There is a level of diversity on residential circuits with many small customers such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential customers on the circuit. Such diversity does not exist to the same extent on circuits serving larger customers, and thus non-coincident demand charges are more reasonably a part of commercial and industrial distribution rates. As a result, it would be reasonable to collect T&D costs from residential customers based on their average demand over a summer on-peak TOU period that covers just the hours when the circuit is most likely to peak. This can be accomplished through a volumetric TOU charge to recover T&D costs during these peak hours. A customer's kWh usage over the peak period measures the customer's contribution to the average demand during those hours and would be a reasonable, cost-based charge. An even more accurate rate would be a very high Critical Peak Pricing (CPP) rate, which are volumetric TOU rates that charge very high on-peak rates to customers in a limited number of high-demand hours each year that the utility or system operator declare on a day-ahead basis.

Q14: Given new metering technology, should the Commission re-evaluate the role in rate design of traditional maximum demand charges?

A14: Yes. Fundamentally, measuring a customer's "demand" is simply measuring its energy use over a different, shorter time period (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). It is simply the traditional way that utilities have charged large customers for certain costs. However, demand charges are increasingly obsolete because, with new metering technology, focused TOU rates will be much more accurate than traditional 15-minute demand charges. Here is the perspective of one expert, Bill Marcus of JBS Energy, who has represented residential customers in state regulatory cases in many states for three-plus decades, in the 2007 SDG&E general rate case that first adopted Option R rates with reduced demand charges for non-residential solar customers in California:

> *Demand charges were invented almost 100 years ago as a crude approximation of system peak costs. The individual customer's peak could be measured, even though the customer's contribution to the system peak could not be measured. The utility charged for what it could measure. Now that we are in the 21st century, with time-of-use energy meters in wide use and advanced meters coming, demand charges have outlived a significant portion of their rationale.*
>
> *High demand charges also make distributed generation (DG) more risky and less economic, as a short outage of the customer's distributed generation will result in payment of the entire demand charge. In the case of SDG&E, which is a relatively isolated load pocket, DG should be actively encouraged, not discouraged. The alternative to DG is either expensive transmission line construction or expensive construction of central station power plants in the area, or both. SDG&E can profit through increased rate base (with equity returns above the cost of capital) by building generation and transmission, can make deals with affiliates for development of generation, and has made the claim that purchased power also requires an equity cushion. However, DG serving customer loads does not have the built-in opportunity for profit, thus SDG&E has an economic incentive to discourage it. Its rate design for large customers does exactly that.*
>
> *Additionally, there is a strong rationale for avoiding the use of the blunt instrument of a demand charge. Costs in the highest peak hours are relatively high and not only for the conventional reasons shown in marginal cost analysis (high energy prices plus capacity need). There is also a relatively large block of costs that SDG&E has not included anywhere in its marginal costs; these are costs for "glue" to hold the utility system together, specifically ancillary services, ramping, and out of market and out-of-sequence purchases by the ISO. For SDG&E, many of these services are provided at high cost by inefficient gas-fired steam units. These costs are not a simple percentage of system energy costs but tend to balloon (even as a percentage of energy cost) as the system moves closer to the peak. Cost causation would suggest raising energy charges in hours close to the peak to provide incentives for demand reduction and demand response that would reduce the size of these types of costs.*[19]

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[19] CPUC A. 07-01-047, Prepared Testimony of William B. Marcus on behalf of Utility Consumer Action Network (served August 10, 2007), at pp. 41-42.

Some jurisdictions are now doing exactly what Mr. Marcus recommended, replacing demand charges with TOU and CPP rates. This represents a far more accurate, targeted, and cost-based means to charge customers than the traditional 15-minute maximum demand charge.

E. Cautionary Tales: Salt River Project and SPP's Green Pricing

Q15: Are you aware of any other utility in the Southwestern U.S. that has implemented a rate structure for NEM customers similar to the one that NV Energy has proposed?

A15: Yes. Earlier this year, the Salt River Project (SRP), Arizona's second-largest electric utility, established a new Standard Electric Price Plan under which all new customers deploying customer-sited solar systems are required to take service using the new E-27 tariff. Although officially adopted by the SRP board in February of this year,[20] 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 fixed charges, as well as demand charges (where demand is measured based on the maximum 30-minute peak demand in the month). Additionally, as compared to the default residential tariff that the new rate plan replaces, solar customers receive significantly lower bill credits for any energy sent back to the grid. SRP is the only utility in the U.S. with a significant number of residential solar customers that has implemented a mandatory demand charge-based rate for solar customers.

Table 3 below shows that SRP's standard residential rates are quite similar in magnitude to current NPC residential rates, especially in the summer. **Table 4** compares SRP's

[20] SRP is a publicly-owned utility not regulated by the Arizona Corporation Commission.

new rate structure for DG customers to NV Energy's proposed NEM2 rates, and shows that they are similar in structure, with NV Energy proposing even higher demand charges than SRP.

Table 3: *SRP[21] and NPC Non-NEM Residential Rates*

Utility	Months	Monthly Charge ($/Month)	Tier 1: First 700 kWh ($/kWh)	Tier 2: 700-2000 kWh ($/kWh)	Tier 3: 2000+ kWh ($/kWh)
SRP Basic	Summer Peak (Jul-Aug)	18.50	0.1168	0.1180	0.1331
	Summer (May-Jun & Sep-Oct)	18.50	0.1102	0.1121	0.1226
	Winter (Nov-Apr)	20.00	0.0792	0.0792	0.0792
NPC RS	Annual (Jan-Dec)	12.75	0.11642		

Table 4: *SRP E-27 (200 amp, 3-10 kW) and NPC Proposed NEM2 Rates*

Utility	Rate Schedule	Months	Monthly Charge ($/Month)	On Peak Energy ($/kWh)	Off Peak Energy ($/kWh)	Summer On Peak Demand ($/kW)	Maximum Demand ($/kW)
SRP	E-27	Summer Peak (Jul-Aug)	30.94	0.0633	0.0423	17.52	NA
		Summer (May-Jun/Sep-Oct)	30.94	0.0486	0.0371	14.63	NA
		Winter (Nov-Apr)	32.44	0.0430	0.0390	5.46	NA
NPC	RS-NEM	Annual (Jan-Dec)	18.15	0.05470			14.33
	ORS-NEM	Summer (Jun-Sep)	18.15	.09147	0.05016	22.15	4.04
		Winter (Oct-May)	18.15	NA	0.04727		4.04

If anything, NPC's proposed NEM2 rates are more onerous for potential DG customers than those that SRP implemented, because NPC is proposing higher demand charges than those which SRP adopted. We have compared the change in the bill savings from solar for an average residential solar customer, based on NV Energy's NEM2 proposal for NPC and SRP's new E-27 rate for residential DG customers. As shown in **Table 5** below, NPC's NEM2 proposal produces a 37% reduction in solar bill savings for the

[21] Source for SRP rates is www.srpnet.com/prices/home/customergenerated.aspx.

average residential solar customer, compared to a 35% reduction for the same customer under SRP's E-27 rate.

Table 5: *Comparison of Bill Savings Impacts – NVE NPC vs. SRP E-27*

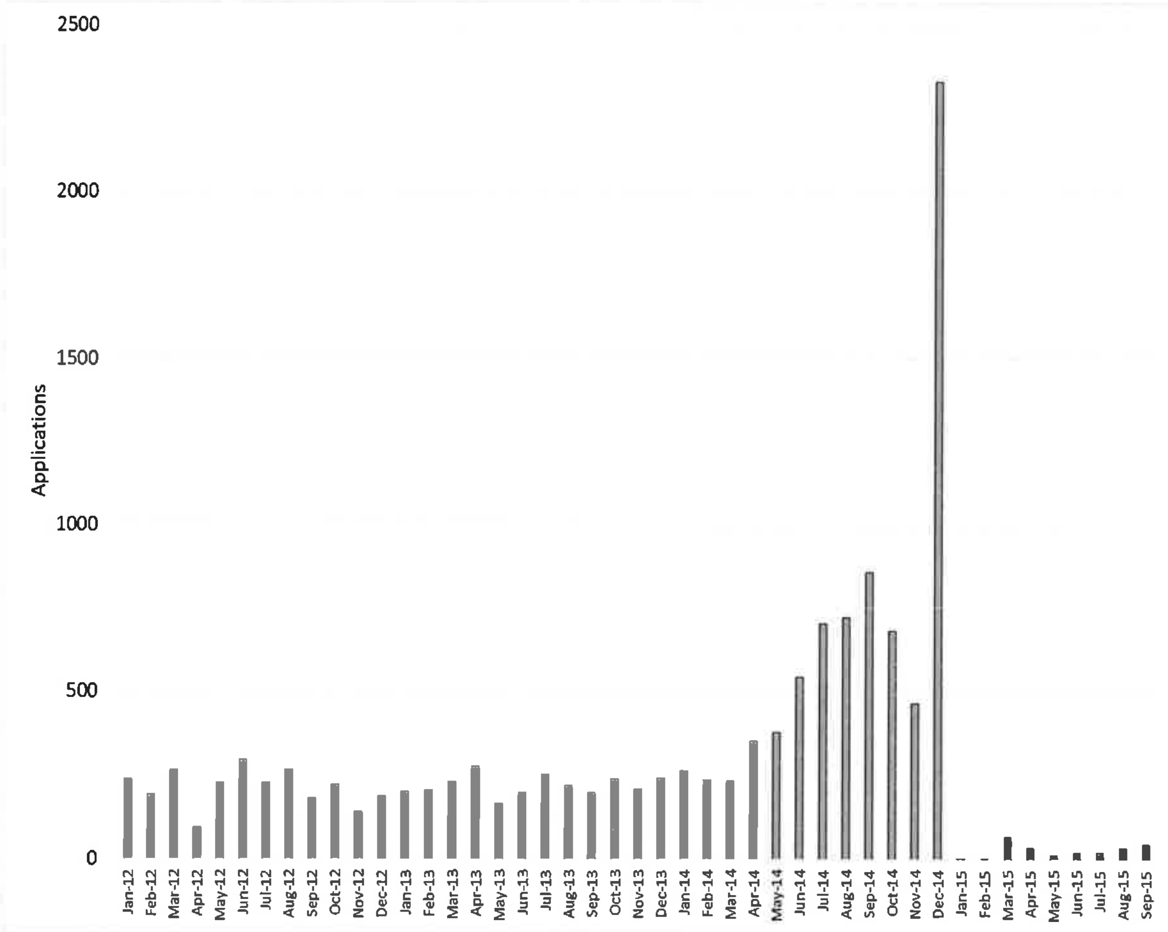
Utility	Solar Generation (kWh)	Flat Rate No Solar	Flat Rate with Solar	Simple 3 Part with Solar	*Bill Savings ($ and $/kWh)*		
					Old Rate	New Rate	% Change
NVE NPC	10,989	$2,262	$1,081	$1,522	$1,181	$740	($441)
Impact of NPC RS-NEM Proposal on Customer Bill Savings→					0.107	0.067	**-37%**
SRP	10,989	$2,158	$1,046	$1,440	$1,111	$717	($394)
Impact of Salt River Project E-27 Rate on Customer Bill Savings →					0.101	0.065	**-35%**

Q16: What has been the impact of SRP's E-27 rate for residential DG on its solar market in the nine months since the rate was adopted?

A16: The impact of the new rate structure on the solar market in SRP's service territory has been nothing short of devastating in terms of solar adoption. Below is a table that provides an overview of monthly solar applications from 2012 through September 2015.[22]

[22] Data from www.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 5: *Solar Applications in SRP Territory*



As can be seen in the figure, monthly applications declined abruptly after December 2014, indicating 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, 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 nine months of 2015 to the same nine months in 2014 shows a decline of 95% in the average number of applications received each month. The solar market in SRP's territory has not rebounded in the nine months after the new SRP rates took effect. Thus, the impact of a new rate structure that is similar to, but not quite as onerous as what NV Energy has proposed, has been almost a complete shutdown of the solar market in SRP's service territory. The intent of SB 374 would not be fulfilled if the same result were to occur in Nevada.

Q17: NV Energy has admitted that, under its NEM2 rates, a customer who wishes to install solar DG would have to pay a premium to continue service from the utility, when one considers both the NEM2 rate and the cost of a solar system. Are there any examples in Nevada of a utility asking customers to pay a premium in order to obtain a supply of renewable energy?

A17: Yes. SPP's Green Energy Choice program allows customers to pay a premium, currently 4.2 cents per kWh, to increase the percentage of renewable energy that serves them.[23] This premium is similar to the reduction in bill savings for solar DG customers from the NEM2 rate, as shown in **Table 1** above; in other words, if NV Energy's NEM2 rates are approved, future solar customers are likely to have to be willing to pay a premium similar to the Green Energy Choice program. Moreover, they will have to pay such a premium over the long-term life of their solar system; this is more onerous than Green Energy Choice which has a minimum commitment of just 12 months. Even with this lower level of commitment, SPP's experience to date with Green Energy Choice is instructive: very few residential or small commercial customers have indicated a willingness to pay such a premium. As of the end of 2014, just 15 residential customers and 2 small commercial customers have signed up for this program, and SPP billed these customers just $8,626 in calendar 2014 under the tariff.[24]

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[23] Based on current prices for green energy under the Northern NV Green Energy Choice program. See the FAQs for this program at: https://www.nvenergy.com/renewablesenvironment/renewables/greenenergy/index.cfm.

[24] NV Energy, *Portfolio Standard Annual Report for Compliance Year 2014* (filed March 31, 2015), at p. 25 and Appendix 5.4; hereafter "2014 RPS Compliance Report.".

III. SUMMARY OF TASC'S NEM2 RATEMAKING PROPOSAL

A. NVE's Three-part Rate Should Be Rejected.

Q18: What is TASC's principal recommendation with respect to the NEM2 rate structure in Nevada?

A18: The Commission should reject NV Energy's proposed NEM2 rates, and should direct NV Energy to continue to provide net metering at existing retail rates for residential and small commercial customers, as is now the practice under NEM1. As discussed in more detail in the next section, to the extent that the NV Energy net metering program results in additional costs, those costs can be collected from NEM customers through interconnection and application fees. This will prevent any unreasonable cost-shifting, consistent with SB 374.

In support of TASC's recommendation, the testimony of TASC's witness Tim Woolf discusses why NVE's proposal is poor policy and fails to advance the goals of SB 374. Bill Monsen's testimony for TASC discusses why NEM customers should not be in a separate customer class, and why NV Energy's marginal cost of service (MCOS) for NEM customers does not differ significantly from the MCOS for other customers in the same class, for the utilities' major categories of costs for energy, generation, transmission, and distribution. My testimony above discusses why NV Energy's use of demand charges in its NEM2 rate will present a major barrier to customer adoption and would not be a cost-based rate design for solar customers. The bottom line is that NV Energy's NEM2 proposal would devastate private investment in a diversified renewable portfolio in Nevada that includes distributed solar, contrary to the clear goals of the NEM statute.

B. Any Additional Customer-related Costs Associated with DG Should Be in Upfront Interconnection and NEM Application Fees.

1. Metering

Q19: What incremental meter-related costs does NV Energy propose should be paid by NEM customers?

A19: There are two meter-related issues in NVE's proposal, one relating to the need for a separate generation meter and the second to the incremental upfront costs for bidirectional meter programming and inspection. I will discuss and provide TASC's recommendation on the generation meter first and on the upfront costs second.

Q20: Should the Commission adopt NV Energy's proposal to require NEM2 customers to install a generation meter, at the customer's expense?

A20: No. As discussed in Mr. Monsen's testimony,[25] there is no need for NV Energy to require all NEM2 customers to install a generation meter. Historically, the rationale for generation meters has been to allow NV Energy to claim the portfolio energy credits (PECs) from customer-generators who receive an incentive under the Renewable Generations program.[26] However, this program will be ending in the near future. Presumably, the utility's primary rationale for requiring these meters in the future is to perform load research, which only requires metering a small, statistically valid sample of a customer class – perhaps 1%.[27] Given that a significant portion of NEM1 customers

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[25] Direct Testimony of Monsen, pp 35-38.

[26] See NRS 704.775(3)(a).

[27] For example, the NPC Narrative, Vol. 2., p. 19, states that "Generation meters will facilitate compliance with SB 374's requirement that Nevada Power assess the effect of DG on its distribution

already have generation meters, it is questionable whether the Company would need additional generation meters on NEM2 customers in order to obtain a statistically valid sample of NEM customers for load research purposes. If in the future, for some reason, the Company needs load research data specifically on the generation output of NEM2 customers, it should install the small number of meters needed for that purpose at its own expense, as part of its general load research budget, as it does with load research activities and costs for all of its other customer classes.

The utilities' narratives also mention the possible need for generation meters so that NV Energy can claim emission credits under the new federal Clean Power Plan (CPP).[28] Just as the PECs from DG today allow NV Energy to comply with the state's Renewable Portfolio Standard, any future CPP credits from DG would benefit all NV Energy ratepayers by reducing the utilities' CPP compliance costs. As a result, just as with PECs today, the costs of the metering needed to secure such credits should be borne by the utility because all ratepayers will benefit.

It is possible that NEM2 customers may want a generation meter in order to account for the RECs which they own, or simply to collect the output data from their generator. In this case, NV Energy should offer to split the cost of the generation meter 50/50 with the customer, provided the customer also agrees to make the generation meter data available to the utility for load research purposes.

Q21: Are you aware of any other utility that requires DG customers to install a generation meter, at customer expense, without a clear DG-related purpose for this

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system, accurately measure the cost of service, and could aid in demonstrating compliance with the Clean Power Plan." The first two of these functions are load research activities.

[28] *Ibid.*

meter (such as measuring renewable energy credits [RECs] or making performance-based incentive [PBI] payments)?

A21: I have reviewed research on requirements for DG customers to install generation meters covering 34 utilities in 17 states. No other utility requires customers to pay for a generation meter without a clear program purpose for that meter.

Q22: Please discuss the incremental upfront costs for bidirectional meter programming and inspection that NV Energy would assign to NEM customers.

A22: NVE says that metering costs are higher for NEM customers than non-NEM customers due to the additional programming and inspection costs required for NEM customers. In other words, the meters are the same as those used for non-NEM customers, but added programming and inspections are required at the time of installation of the NEM system. As noted by Mr. Monsen, such additional costs are logically associated with the initial interconnection process, and are best collected through an upfront fee for interconnection.[29] Such upfront processing charges for interconnection applications are not uncommon, with a typical fee of no more than $100 for residential customers.[30] TASC recommends that NV Energy implement the following upfront interconnection charges for new NEM customers, based on the additional programming and inspection costs for new NEM installations. The Commission should revisit these costs in subsequent GRC cycles to ensure that they remain cost-based.

Table 6: *TASC Recommended NEM Interconnection Charges*

Customer Class	Interconnection Charge
RS	$80

[29] Direct Testimony of Monsen, pp 34-35.

[30] Other utilities with such residential interconnection charges include Xcel Energy in Colorado, and Avista and Idaho Power in Idaho.

RS-M	$90
GS	$130

TASC does not recommend an interconnection charge for the NPC LRS class, as the utilities' cost estimate for the bidirectional meters for this class is actually lower than the cost of regular meters for these customers.[31]

2. Customer Accounts and Customer Service Costs

Q23: NV Energy also asserts that its customer accounts and customer service costs are higher for NEM customers. How should these costs be recovered?

A23: As discussed in Mr. Monsen's testimony, these higher costs are associated principally with responding to questions from new NEM customers about interconnection, incentives, and initial questions about billing.[32] These costs are largely associated with the process of becoming a NEM customer, and thus are logically collected through an upfront application fee. Responding to questions about incentives will no longer be necessary in the near future once the RenewableGenerations program ends.[33] It is my understanding that NV Energy has recently instituted a non-refundable $35 application fee for NEM service. This fee is nonrefundable even if the NEM system is not installed. The additional annual customer accounts and customer service costs associated with NEM are about $23 per customer per year. These costs can be expected to decline once the RenewableGenerations incentives end, and as the penetration of DG increases, such that potential customers are able to obtain information about DG and NEM from their

[31] See NPC Narrative, at Table 3-1.
[32] Direct Testimony of Monsen, pp. 38-43.
[33] According to NVE, as of October 24, 2015, there are 54 MWs remaining in the program. See: https://nvenergy.powerclerk.com/Default.aspx

own research, from word-of-mouth via neighbors who have adopted DG, and from a broader base of solar installers. TASC observes that the solar industry has made significant progress in reducing such "soft costs" in recent years, and hopes that NV Energy will be able to participate in that progress. However, reductions in these customer costs will be much more difficult if NV Energy's very complex NEM2 rates are implemented, which are likely to result in customer confusion, more complex inquiries to the utility, and a far lower rate of customer adoption. The impact would be to increase these costs per customer, particularly when spread across the far smaller number of customers who might actually decide to adopt solar at NV Energy's proposed NEM2 rates.

The added customer accounts/customer service costs of $23 per customer per year are calculated over the entire population of NEM customers, not just over new NEM customers. However, due to the recent rapid growth of the NEM program, a significant portion of this population represents new NEM customers. Thus, TASC expects that the current $35 per customer application fee, if left in place, will cover most, if not all, of the incremental customer account / customer service costs associated with the continued offering of NEM, assuming that NEM1 remains in place and both the utility and the solar industry can focus on further reductions in these soft costs of DG adoption. This fee and the underlying costs could be reviewed in more detail and with more experience in the utilities' next GRCs, and adjusted then as appropriate.

C. TASC's Grandfathering Proposal

Q24: The Commission's September 1, 2015 order in this docket allows new DG customers to continue to take service under the current NEM1 structure, even though NV Energy has reached its 235 MW NEM cap. However, these above-cap, "Interim" DG customers potentially are subject to the Commission's determination in this case

concerning the NEM structure that will apply to them going forward. What is TASC's proposal for these Interim DG customers?

A24: TASC proposes to continue the NEM1 structure whereby DG customers can use net metering based on existing residential and small commercial rates. If this proposal is adopted, the Interim DG customers who have taken NEM service since September 1, 2015 can simply continue under their present NEM service.

TASC also recommends that the NEM application and interconnection fees that it has proposed should take effect when the order in this docket becomes effective. Thus, for Interim DG customers, if they have not interconnected as of the effective date of this order, then they would pay the new interconnection fee.

Q25: If the Commission makes significant changes to NEM, how should existing NEM customers be treated?

A25: Interim NEM customers that take service prior to the Commission issuing an order on NEM2 rates, and NEM customers who have taken service below the 235 MW cap, should be grandfathered under NEM1 rates and tariff rules. There are several important reasons for this treatment.

- Through the end of 2015, DG customers who receive RenewableGenerations incentives will provide NV Energy with RECs with a 2.45x multiplier. These "multiplied" RECs will have significant additional value to NV Energy for RPS compliance.

- The Commission should recognize that existing NEM customers have made long-term commitments to DG systems in reliance on existing rates and with the encouragement of the existing incentive program (which requires customers to interconnect under the NEM tariff), albeit under conditions of substantial uncertainty. In particular, for the reasons discussed above, current residential and small commercial customers are highly unlikely to have been able to obtain the education or data needed to understand the impacts of NV Energy's complex NEM2 rate structure, particularly the impact of the proposed demand charges.

As a result, the imposition on interim DG customers of substantially different rates and terms of service would be unfair and may force their contracts "underwater."

- TASC fully recognizes that when NEM customers decide to install DG under a NEM tariff, they bear the risks and rewards of typical changes over time in the levels and design of utility rates. However, the changes that NV Energy has proposed in these dockets are truly extraordinary and are far beyond what is typical through the normal ratemaking process. A regular utility customer would surely complain that a proposed 35% to 40% rate increase is extraordinary and excessive; so too is the comparable rate increase for solar customers that the utilities have proposed.

Q26: If NEM2 rates are substantially different than NEM1 rates or TASC's proposal, when should the Commission implement NEM2 rates?

A26: The Commission can adopt a new NEM2 rate design by December 31, 2015, as the statute requires. However, as discussed in more detail below, a new NEM2 rate design will not impact other ratepayers until new rates take effect after the utilities' next general rate case (GRC) decisions. Accordingly, the Commission should allow new DG customers who commence service after December 31, 2015 to take service under the existing "interim" NEM1 rates until the utility GRCs, and then move to the "permanent" NEM2 rate when rates approved in those GRCs take effect.

IV. COST-OF-SERVICE ANALYSES DO NOT FULLY CAPTURE THE LONG-TERM BENEFITS OF NET-METERED DISTRIBUTED GENERATION

Q27. Does NVE's proposed NEM2 tariff account for the all of the benefits that DG customers provide to the NVE system?

A27. As noted in Mr. Woolf's testimony, a cost-of-service analysis does not capture fully the benefits of renewable DG to other NV Energy ratepayers.[34] As discussed in Mr. Monsen's testimony, NV Energy's retail rates and its NEM1 tariff capture the marginal or avoided energy, generation, transmission, and distribution benefits that result when customers install solar, especially after correcting for the flawed assumptions in NV Energy's marginal cost-of-service analysis.[35] These are the principal direct benefits of net-metered DG. However, the marginal cost of service study does not consider other important long-term benefits that accrue to all customers as a result of the installation of solar by NEM customers.

Q28: How would you characterize these additional benefits?

A28: Generally, these are benefits that will accrue to NV Energy ratepayers over time, as a result of the addition of these new, long-term renewable resources to the NV Energy system. These benefits can be characterized as follows:

1. Quantifiable long-term benefits that will reduce utility system costs borne by ratepayers. For example, the **renewable attributes** of net-metered DG will reduce the utilities' future costs to comply with RPS or CPP requirements. **Market price mitigation** benefits will reduce the future market prices of the utility's wholesale purchases of power.

2. Electric system benefits that may not reduce ratepayer costs but that are valuable to customers, such as the enhanced **reliability and resiliency** of their electric service.

[34] Direct Testimony of Woolf, pp.17-21.
[35] Direct Testimony of Monsen, pp. 14-44.

3. **Societal benefits**, "externalities," that do not impact rates, but that are important to citizens in NV Energy's service territory generally. These include additional **environmental benefits** from avoiding the harmful impacts of carbon emissions and criteria pollutants and the **local economic benefits** of a growing DG industry.

Q29: Why is it important for the Commission to consider these additional benefits?

A29: TASC has shown in its testimony that there is no cost shift under existing NEM rules once the errors have been corrected in NV Energy's MCOS. The presence of additional long-term benefits from renewable DG simply should confirm for the Commission that there is no reason to change the structure of NEM. Contrary to the information set forth in NV Energy's applications and the analysis of this information as provided by TASC, even if the Commission believes there is some amount of cost shift from NEM on a cost-of-service basis, these additional benefits should be weighed by the Commission in deciding whether such a cost shift is unreasonable, given that SB 374 does not prohibit all cost shifts, just ones that are unreasonable. TASC emphasizes that it is not asking that DG customers be compensated directly for these additional long-term benefits, just that the Commission recognize and consider these benefits as it balances the interests of customers who make investments in renewable DG, other customers, and the state of Nevada as a whole.

Q30. Has the Commission allowed stakeholders to account for externalities in evaluations of utility cost of service studies?

A30. Yes. In Docket No. 14-06009, the Commission's March 25, 2015 order specifically allowed parties to address the impact of externalities on the conclusions of cost of service studies.[36] NV Energy declined to do so in its proposal in this docket, failing to discuss or even mention the long-term direct or societal benefits associated with NEM.[37] The utilities' silence on these issues demonstrates an implicit position that renewable DG has no long-term direct or societal value for Nevada, a position with which TASC strongly disagrees.

Q31. What do you conclude?

A31. NVE's cost of service studies have failed to recognize or account for the long-term direct and external societal benefits provided by NEM customers. Even if NEM customers were slightly more expensive to serve, the marginal cost of service does not include important long-term benefits of NEM that will reduce costs for utility ratepayers in future years and that the Commission should weigh in determining whether a separate rate class for NEM customers is justified.

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A. Renewable Attributes.

Q32: Are there benefits to NV Energy's ratepayers from the development of additional renewable DG in Nevada?

A32: Yes. For example, solar DG developed in NV Energy's service territory that is incentivized through the utilities' SolarGenerations program provides PECs (also known as renewable energy credits [RECs] in other states) to NV Energy. The NV Energy

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[36] See Order Adopting Report dated March 25, 2015 in Docket No. 14-06009, attached Report at pp. 25-26.

[37] See NV Energy response to TASC DR 107 attached to this testimony as Exhibit RTB-4: "NVE did not attempt [...] to perform an analysis to identify 'benefits' provided by and to non-NEM and NEM customers."

utilities can use these PECs for compliance with Nevada's Renewable Portfolio Standard (RPS). As noted above, through the end of 2015, NV Energy will receive a 2.45x multiplier for PECs from DG; in 2016 the multiplier drops to 1.0. So the PECs from Interim NEM customers have particular value to NV Energy and its ratepayers.

Q33: The Renewable Generations incentives are likely to end in the near future, perhaps in 2016.[38] At that point, new DG customers who come on-line after that date will own the PECs/RECs associated with their output. At that point, will this renewable generation still have value to NV Energy's other ratepayers?

A33: Yes. The Nevada RPS requirement is 25% of a utility's sales in 2025. DG output acts to reduce directly the utility's sales, and thus future DG will reduce the utility's 2025 RPS requirement by 25% of DG output. Thus, even if the DG customer retains the PECs/RECs from his facility, other ratepayers will receive a benefit equivalent to 0.25 PEC from each MWh of output from all incremental DG facilities interconnected to the NV Energy system after the RenewableGenerations incentives end.

In addition, DG customers on NV Energy's system will continue to be NV Energy customers. If the Nevada utilities were to need additional PECs in the future, DG customers already on their system who were not providing PECs to them would be a convenient source for the purchase of the needed additional PECs, from a source with an ongoing relationship with the utilities. The willingness of current DG customers to provide PECs to NV Energy in exchange for today's low SolarGenerations incentive (plus a free generation meter) indicates that DG customers could be a low-cost source of

[38] As of October 24, 2015, there are 54 MWs remaining in the program. https://nvenergy.powerclerk.com/Default.aspx.

PECs/RECs for NV Energy in the future. The current 5-year performance-based incentive of $15.90 per MWh is equivalent to a 25-year REC price of $6.86 per MWh.[39]

Q34: NV Energy's most recent RPS report indicates that it has adequate PECs to meet the 2025 RPS goal, assuming successful development of the two large solar contracts approved in Docket No. 15-07003.[40] What developments might increase and advance NV Energy's need for PECs?

A34: There are a number of possible developments that could accelerate the utilities' need additional PECs. First, now that it is clear that the Nevada utilities are likely to meet the 2025 RPS goal, that goal could be increased, as has happened in other states. Second, there clearly is an increasing demand for green power from major corporate customers in Nevada, as indicated by NVE's recent sale of a large amount of PECs to Switch.[41] Third, the value of PECs/RECs may increase as states begin to plan their approaches for compliance with the federal government's Clean Power Plan, which encourages early development of additional renewable generation as a compliance strategy. Fourth, RECs have market value in the West, so NV Energy could sell excess RECs in order to reduce the cost of renewable generation for its customers.

Q35: Isn't it true that the value of RECs today is quite low in the western U.S.?

A35: Yes, but these low prices may not be sustained. For example, NVE's recent sale of PECs to Switch at $3.50 per MWh is low compared to past market values for RECs in the West. However, REC market values in the West fluctuate significantly depending on the

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[39] Assuming solar PV output degrades at 0.25% per year and a 9% discount rate. The current PBI incentive (Step 9 for residential) of $15.90 per MWh can be found at https://www.nvenergy.com/renewablesenvironment/renewablegenerations/index.cfm.

[40] NV Energy response to TASC DR 9, attached as Exhibit RTB-5 to this testimony.

[41] Docket No. 15-08005.

demand for RECs, the supply of RECs on offer, and the compliance status of utilities in the various western states with active RPS procurement programs. Several years ago, utilities were actively seeking new renewable generation to comply with various state RPS requirements; there was less renewable generation available; and REC prices were much higher than today. The following table presents public data on PacifiCorp's sales of RECs over the last five years, showing that RECs were worth over $30 per MWh in 2010-2011, but that value has dropped to about $5 per MWh in 2013-2014.[42] NV Energy conducted a reverse RFP to sell RECs in 2014, but decided not to sell any even though it had bids as high as $4 per MWh, indicating that the Company believes the future value of RECs to be higher.[43]

Table 7: *PacifiCorp REC Sales and Prices 2010-2014*

	2010	2011	2012	2013	2014
REC Sales *(GWh)*	3,181	2,282	4,414	1,780	793
REC Revenues *($ million)*	$101.1	$72.8	$81.3	$7.60	$4.41
REC Price *($/MWh)*	$31.79	$31.91	$18.41	$4.27	$5.56

Today, the major utilities in states with RPS programs – such as California, Oregon, Nevada, and Utah – are fully resourced to meet these states' near-term RPS goals. However, future REC values may increase as RPS requirements in western states are raised or extended, such as California's recent enactment of a new RPS target of 50% renewable by 2030. In addition, the well-documented increasing demand for green power from major corporate customers such as Switch also may tighten supplies and

[42] See *Prepared Direct Testimony of R. Thomas Beach on behalf of the Sierra Club* in Utah Public Service Commission Docket No. 15-035-53 (filed September 16, 2015), at p. 27 (Table 1).
[43] 2014 RPS Compliance Report, at pp. 27-28.

increase prices in REC markets.[44] Finally, as I noted above, SPP charges a premium of $42 per MWh to residential customers in northern Nevada who wish to purchase additional renewable energy, even though today's REC prices are far lower. This premium is based, not on the marginal cost for PECs/RECs, but on SPP's recent embedded cost difference between its renewable resources and its overall energy costs.[45] Thus, to the extent that NV Energy can acquire PECs/RECs from DG customers at less than $42 per MWh, other ratepayers would appear to benefit from reduced per unit costs for renewable generation.

Q36: One of the arguments that NV Energy uses for requiring future DG customers to install a generation meter is that the utility wants to use this output to show compliance with the federal Clean Power Plan.[46] What is the potential value of additional renewable generation to Nevada in terms of reduced carbon emissions?

A36: The value of reductions in carbon emissions from each 100 MW of new solar DG is about $2.5 million per year over the life of these resources, or about $14.60 per MWh. This assumes that each MW of new solar DG displaces gas-fired generation at a heat rate of 8.3 MMBtu per MWh,[47] and uses the mid-carbon scenario for carbon emission costs that NV Energy assumes in its IRP ($20 per short ton in 2020, escalating at 6.8% per year).[48] These benefits can be considered a proxy for the future costs for compliance with carbon regulations such as the CPP that the utility may avoid by increasing its purchases of renewable generation.

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[44] See GreenBiz, "Apple, Google, and the evolving economics of energy" (February 11, 2015), at http://www.greenbiz.com/article/google-inc-apple-inc-wind-solar-fossil-fuels-renewable-energy-economics.

[45] Based on the calculation outlined in SPP's Schedule No. NGR, the NV GreenEnergy Rider.

[46] NPC Narrative, Vol. 2., p. 19. NV Energy has not yet developed a plan to comply with the CPP. See NV Energy response to TASC DR 9, attached as Exhibit RTB-6 to this testimony.

[47] Based on 2016 forward price data for Mead (power) and Topock (natural gas).

[48] See Docket No. 14-05003, 2013 IRP First Amendment, at Volume 4, at p. 117, Figure PF-8.

B. Market Price Mitigation Benefits

Q37: The development of renewable DG projects using solar, wind, and hydro contributes to the overall development of renewable generation in Nevada and on the Western Electricity Coordinating Council (WECC) grid. What impact will an increasing penetration of renewable resources have on the electric markets in the western U.S. from which NV Energy purchases power?

A37: This new solar and wind generation will displace the most expensive fossil-fired or market resources that NV Energy would otherwise have generated or purchased. The addition of this local generation will reduce the demand which the utility places on the regional markets for electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits the Nevada utilities when they buy power or natural gas in these markets. As discussed in NPC's most recent IRP amendment, NPC expects to have a short position in these markets for many years into the future, and will therefore rely on wholesale market purchases to serve load in its balancing area.[49] This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources. The magnitude of these benefits will depend on the overall amount of renewables on the western grid.

Q38: Are you aware of any modeling of this benefit in the West?

A38: Yes. The National Renewable Energy Laboratory (NREL) and GE Consulting have undertaken the Western Wind and Solar Integration Study (WWSIS), a major, multi-

[49] *Ibid.*, Volume 3, pp. 13-14 (Figure 5-3) and pp. 24-27 (Tables S-12 to S-15).

phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S., including the NV Energy footprint.[50] This modeling has included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below. The high penetration solar cases (15% to 25% penetration) in the WECC result in 10% to 20% reductions in spot market prices.

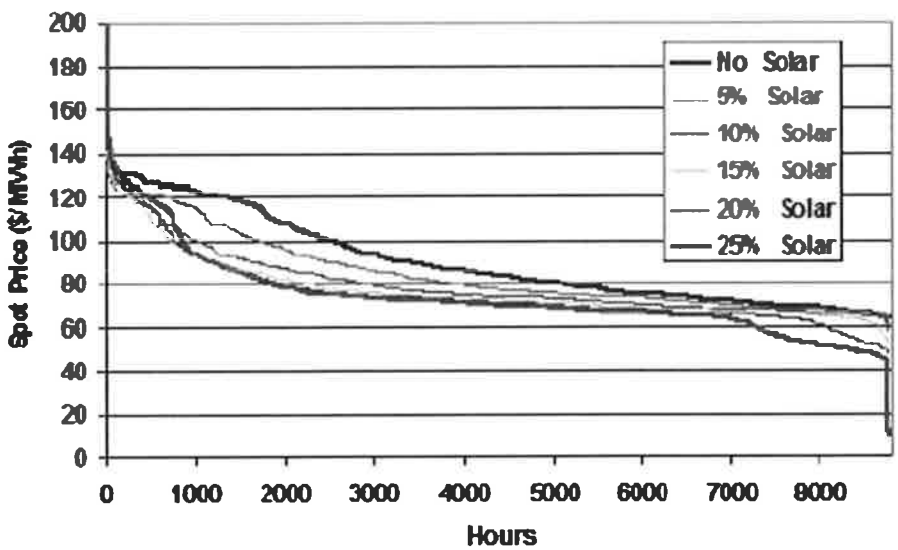

Figure 19 – Arizona Spot Price Duration Curves.

C. **Reliability and Resiliency**

Q39: How does DG enhance the reliability and resiliency of the utility system?

A39: Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to fail at the same time. Furthermore, the

[50] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and Figure 19. This report, as well as all reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

impact of any individual outage at a DG unit will be far less consequential and less expensive for ratepayers, than an outage at a major central station power plant. DG is located at the point of end use, and thus reduces loadings on the T&D system.

Finally, solar DG can serve as the generation source for solar-battery systems or local micro-grids that can enhance the resiliency of electric supplies for critical infrastructure essential to public health and welfare. TASC acknowledges that these benefits will be realized over time, as storage is added to DG solar systems. Nonetheless, DG is a foundational element necessary to realize this benefit, in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that hopefully will be developed in the future. Just as the Commission has authorized ratepayer-funded investments in smart meters for yet-to-be realized benefits, solar DG, storage, smart inverters, smart thermostats and other load-management technologies should be recognized as providing the foundation for a future grid that is more resilient and reliable. Accordingly, these reliability benefits should be recognized as a broad societal benefit of distributed generation.

D. Local Economic Benefits

Q40: Does DG provide net benefits for the local economy?

A40: Yes. The Commission's NEM Study reviewed the literature for the economic benefits of net-metered DG, and concluded that DG provides greater economic benefits than the central generation it displaces, but that these benefits often can be offset if DG raises utility rates.[51] It was the conclusion of the NEM Study, and it is the conclusion of TASC's analysis now, that NEM1 will not raise rates by shifting costs to other ratepayers. Thus, the Nevada economy should benefit from a robust and growing DG industry in the state.

Due to economies of scale, central station renewable generation has lower costs per kW than DG, although the gap may be narrowing as DG soft costs are reduced, because soft costs comprise a larger share of the costs of DG solar compared to utility-scale projects.[52] However, these higher costs are offset by the fact that DG provides retail power delivered at the point of end use, while central station renewables provide wholesale power that still must be delivered to customers. Furthermore, DG has the added benefit of enabling and enhancing customer choice. In addition, a portion of the higher soft costs of DG – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in excess of what would be spent on wholesale, central station renewable generation. These local costs are an appreciable portion of the soft costs of DG, and will result in a greater stimulus to the local economy than central station renewables.

E. Environmental Benefits

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[51] Docket No 13-07010, PUCN NEM Study, at pp. 144-147. "Existing studies indicate that the solar industry does indeed create jobs, but the negative impact of average electricity retail rate increases tends to outweigh the positive impacts by a small margin."

[52] See Galen Barbose and Naïm 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), report summary, at Slide 33. "The continued decline in installed prices is attributable to steady reductions in non-module costs and suggests that recent efforts by industry and policymakers to target soft costs have begun to bear fruit."

Q41: Are there additional environmental benefits to society from renewable DG, beyond the quantifiable renewable attributes you have discussed above that are a direct cost for utility ratepayers?

A41: Yes. There are additional, societal benefits from reductions in emissions of both carbon and criteria pollutants that are not included in the direct costs to the utility and its ratepayers to control or reduce these emissions. These additional benefits are associated with avoiding the adverse societal and health impacts of these emissions.

Social Cost of Carbon. As Pope Francis recently wrote in his encyclical calling for "all people of goodwill" to take action on climate change, "The climate is a common good, belonging to all and meant for all."[53] The social cost of carbon (SCC) is "a measure of the seriousness of climate change."[54] It is measure of the expected societal impacts of carbon pollution, above and beyond the costs that may be required to reduce carbon emissions. Thus, it measures the societal benefits of actions to reduce greenhouse gas emissions. The carbon costs included in NV Energy's IRP's base case do not fully capture the benefits of reducing carbon emissions, i.e. the true cost that carbon pollution imposes on society.

The most prominent source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[55] These values have been vetted by numerous government agencies, research institutes and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference

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[53] Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

[54] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[55] Interagency Working Group on Social Cost of Carbon, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" (Revised July 2015). Available at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

scenarios.[56] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values, given in the table below.

Table 8: *Social Cost of Carbon*[57]

	Discount Rate / Statistic			
	5% /Average	3%/Average	2.5%/Average	3%/95th percentile
Social Cost of Carbon ($/tonne)	**11**	**36**	**56**	**105**

Figures in 2007$ per metric ton of CO_2.

TASC recommends use of the mid-case SCC value of $36 per metric tonne, with annual escalation of 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[58] While estimating the social cost of carbon contains many inherent uncertainties, these values have been characterized as conservative by the Intergovernmental Panel on Climate Change and by the EPA.[59] Despite the uncertainties, federal government agencies are required to use these figures in cost-benefit analyses. The mid-range real discount rate of 3% used in the SCC is a typical societal discount rate often used in long-term benefit/cost analyses.[60]

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[56] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

[57] *Id.*, p. 13.

[58] *Id,* pp. 13-14.

[59] As the Intergovernmental Panel on Climate Change wrote in their Fourth Assessment Report, "It is very likely that [social cost of carbon estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Intergovernmental Panel on Climate Change, "Climate Change 2007: Synthesis Report." at p. 69. Available at http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf. The EPA agrees its cost figures are highly conservative approximations, and advises that even the highest values should be understood to under-estimate the true societal costs of climate change, as the models "do not currently include all of the important physical, ecological, and economic impacts of climate change … because of a lack of precise information on the nature of damages." See, e.g., EPA website, "The Social Cost of Carbon," http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

[60] It is also a conservative assumption, when considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs. California Climate Change Center, Our Changing Climate: Assessing

The additional societal benefits from reduced carbon emissions are calculated as the SCC values less the carbon allowance costs assumed in the 2015 IRP ($20 per short ton beginning in 2020). The societal value of reductions in carbon emissions, above the IRP carbon value, for 100 MW of new solar DG is about $2.9 million per year over the 20-year life of these resources, or about $17 per MWh (1.7 cents per kWh), assuming a 3% societal discount rate and that each MW of new solar DG displaces gas-fired generation at a heat rate of 8.3 MMBtu per MWh.

Criteria pollutants (PM 2.5 and NOx). Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM-2.5) causes asthma and other respiratory illnesses, cancer, and premature death.[61] Nitrous oxides (NO_x) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[62] TASC recommends using the health co-benefits from reductions in criteria pollutants that were developed by the EPA in conjunction with the CPP. These benefit estimates are recent, as they were developed last year as part of the technical analysis for the proposed rule. Additionally, for PM-2.5, the figures are specific to Nevada, taking into account population density and emissions factors specific to the

the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

[61] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf, hereafter, "CPP Technical Analysis."

[62] *Id.*

Nevada electric generation fleet.[63] Heath damages from exposure to NO_x come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[64] Based on the recent data in the CPP, the health damages from PM-2.5 and NOx emissions from electric generators in Nevada are, respectively, $122 and $24 per pound. Using standard EPA emission factors for PM-2.5 and NOx emissions from gas-fired

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[63] The EPA health co-benefit figures distinguish between types of PM-2.5, and calculate two separate benefit-per-ton estimates for PM-2.5: for PM-2.5 emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter. See CPP Technical Analysis, p. 4-17. The EPA estimates that approximately 75% of primary PM-2.5 emitted in Nevada is crustal material, with the remainder being elemental or organic carbon. *Id.*, p. 4A-8, Figure 4A-5. As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for emissions from Nevada electric generators. Our calculations are as follows:

For elemental and organic carbon:

$$\frac{425{,}000\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$225.25\ per\ lb\ PM + +$$

For crustal particulate matter:

$$\frac{165{,}000\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$87.45\ per\ lb\ PM\ = \$ = \$87.45\ per\ lb\ PM)$$

Total:

$$(\$225\ \times 0.25) + (\$87\ \times\ 0.75) = \$122\ per\ lb\ PM$$

[64] CPP Technical Analysis, p. 4-14. The EPA calculates health benefits of avoiding formation of either of these pollutants: $7,400 to $31,000 per ton for ozone formation, and $17,000 to $34,000 per ton for PM-2.5 formation, both in 2011 dollars. We include both types of avoided health costs in our calculations, and use the mid-points of EPA's ranges of health benefits. Our calculations are as follows:

$$\frac{44{,}700\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$24\ per\ lb$$

power plants[65] and a heat rate of 8.3 MMBtu per MWh, the societal benefits of reduced emissions of criteria pollutants from 100 MW of solar DG are $2.2 million per year over the 20-year life of these resources, or about $12.70 per MWh (1.3 cents per kWh).

VI. TO THE EXTENT THE COMMISSION REMAINS CONCERNED ABOUT COST-SHIFTING, THE COMMISSION SHOULD DEFER CHANGES TO NET METERING TO THE UTILITIES' NEXT GENERAL RATE CASES

A. NVE's Proposed NEM2 Rates Will Benefit Only Shareholders until the Next GRCs.

Q42: Did SB 374 mandate the three-part rates that the utilities have proposed?

A42: No. SB 374 did not mandate three-part rates, but instead required the Commission to remedy any "unreasonable cost shifting." In Docket No. 14-06009 Commissioner Noble ordered the preparation of the COS studies for NPC and SPP for the purpose of examining the cost-of-service issues concerning NEM customers, and in that docket the parties discussed using these studies as a starting point for development of rates in the next GRC. The first such GRC would be SPP's filing in June 2016. This direction from the Commission in March 2015 predated passage of SB 374.

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[65] Emission factors of 0.0077 lb/MMBtu for PM-2.5 and 0.0146 lb/MMBtu for NOx are from AP 42, the EPA's compilation of air pollutant emissions factors. U.S. EPA, AP 42 Volume I, Fifth Edition, Section 1.4 (*Natural Gas Combustion*), Table 1.4-2. Available at http://www.epa.gov/ttn/chief/ap42/ch01/index.html ("AP 42").

Q43: Even assuming that there is some cost shift as a result of NEM, will raising rates for NEM customers as early as January 1, 2016, reduce the rates of non-NEM customers?

A43: No, it will not, because base rates for non-NEM customers will not change on January 1, 2016. As a result, the implementation of NEM2 will do nothing until the next utility GRCs to remedy any perceived cost shifting. NV Energy agrees that non-NEM rates will not be impacted by this docket.[66]

Q44: Who will benefit from raising rates on NEM customers?

A44: NV Energy's shareholders. Increasing fees on solar customers without decreasing rates for non-solar customers will only increase NVE's earnings. Thus, to the extent that NEM customers pay 35% to 40% more under NEM2 rates, the increased revenues will flow to NV Energy shareholders until the next utility GRCs. If NV Energy's NEM2 rates result in customers not installing DG who might otherwise have installed DG under NEM1 rates, the shareholders will benefit from the full amount of the bill savings that DG customers would otherwise have realized. For example, if over the next year, NEM2 rates result in 10,000 residential customers not installing DG systems averaging 5 kW, this 50 MW reduction in DG capacity would result in about $12 million per year in additional revenues for NV Energy shareholders, assuming about $1,200 per year in bill savings per solar customer with a 5 kW system under the NEM1 tariff.[67]

Q45: Are the NV Energy utilities presently earning more than their authorized return?

A45: Yes, Exhibit 16, introduced in these Dockets at the interim hearing on August 21, 2015, is Nevada Power's notice 15-03 to implement its third quarter 2015 BTER and DEAA.

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[66] See NV Energy Response to TASC DR 22 attached as Exhibit RTB-7 to this testimony.
[67] See the bill savings calculated in NPC Narrative, Vol. 2., Table C-1.

This exhibit demonstrates that NV Energy has earned approximately $33.5 million dollars as of March 2015 in excess of its authorized rate of return. In addition, Nevada Power and Sierra Pacific Power have reported earnings at or above their authorized returns since 2012.[68]

B. The Full Rate Impacts of NVE's Proposal Can Only Be Assessed in a GRC.

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[68] See NV Energy response to TASC DR 66 attached as Exhibit RTB-7 to this testimony. To the extent the Nevada utilities' earned rate of return exceeds the rate of return used to set base general rates, the Nevada utilities are required to refund to customers certain revenues that they would otherwise be able to collect. In July 2010, regulations were adopted by the PUCN that authorizes an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN through energy efficiency implementation rates ("EEIR"). As a result, the Nevada utilities file annually in March to adjust energy efficiency program rates and EEIR for over- or under-collected balances, which are effective in October of the same year. In March 2013, the Nevada utilities filed applications with the PUCN for the twelve-month period ended December 31, 2012 to reset EEIR elements. In September 2013, the PUCN issued an order indicating that EEIR revenue should not contribute to the Nevada utilities earning more than its authorized rate of return. As the Nevada utilities earned in excess of its authorized rate of return in 2012, the PUCN disallowed approximately $16 million in EEIR revenue. More recently, the Nevada utilities have deferred recognition of EEIR revenue collected and have recorded a liability of $13 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2014, indicating that they are still overearning.

Q46: Has NV Energy shown in this case what the impact of its NEM2 proposal would be on the rates of other, non-NEM customers?

A46: No, it has not. The changes to its MCOS that NV Energy has included in its cost studies will impact the rates of other customers, although it is not clear what those impacts will be. Cost shifting, if it exists, can only be remedied fully in the context of a full rate case where all rates may be modified.

C. NVE's Proposal Is Motivated by Berkshire-Hathaway's Corporate Agenda

Q47: Is there evidence that NV Energy's proposal in this docket is motivated by a broader corporate agenda of NV Energy's parent Berkshire Hathaway Energy?

A47: Yes. Berkshire Hathaway Energy (BHE) has made no secret of its desire to impose demand charges on residential customers served by its utilities, including NPC and SPP. BHE representatives have specifically recommended demand charges for customers who install not only DG but also other advanced energy technologies that allow customers greater control over their energy use and costs, in public presentations and congressional testimony:

> *But as the penetration of distributed generation to electric vehicle charging to programmable, controllable thermostats to stationary energy storage grows, the demand charge can be a solution to more equitably collect grid costs as well as create a price signal that encourages efficiency, load shifting and peak demand side management. BHE believes that separating out demand charges is a good way to promote a more fair cost allocation among customers while also motivating customers to reduce strain on the grid. ... A demand charge would more equitably charge each customer for the service required from the grid closer*

to each customer's true cost of service.[69]

NV Energy's comments in Docket No. 15-03010 indicate that it favors adoption, on an opt-out basis, of three-part rates, including demand charges, for all residential customers in Nevada.[70]

Q48: Does this conclude your prepared direct testimony?

A48: Yes, it does.

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[69] *Statement of Jonathan M. Weisgall, Vice President, Legislature and Regulatory Affairs, Berkshire Hathaway Energy*, Before the House Energy and Commerce Subcommittee on Energy and Power, Jun 4, 2015, pages 34-35. See also Brent E. Gale, BHE Senior Vice President, Presentation to LSI Conference, 2014.

[70] See NV Energy September 15, 2015 comments in Docket No. 15-03010, at pp. 2-3 (three-part rates are more accurate, and, with smart meters, residential customers can now be charged three-part rates), p. 5 (favoring opt-out rates), pp. 6-9 (customers can understand demand charges).

AFFIRMATION

STATE OF California)
) ss.
COUNTY OF Alameda)

I, R. THOMAS BEACH, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Direct Testimony, and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked questions set forth herein; my answers thereto would, under oath, remain the same.

R. Thomas Beach

R. THOMAS BEACH

Subscribed and sworn to (or affirmed) before me
on this 24 day of October, 2015, by R. THOMAS BEACH,
proved to me on the basis of satisfactory evidence
to be the person who appeared before me.

Notary Public

NOTARY PUBLIC

COLLIN BECKER
COMM. # 2106174
NOTARY PUBLIC - CALIFORNIA
ALAMEDA COUNTY
My Comm. Exp. 4-9-2019

Docket Nos. 15-07041/42

Exhibit RTB-1

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Docket Nos. 15-07041/42

Exhibit RTB-2

Final Report

Solar (NEM) Rate Preferences Survey Results

June 2015

Prepared for:

SDGE connected

A Sempra Energy utility™

Prepared by:

HINER & PARTNERS, INC.
MARKETING DIAGNOSTICS AND STRATEGIES

CONFIDENTIAL DRAFT – PREPARED IN ANTICIPATION OF LITIGATION

Background and Objectives

SDG&E is interested in testing different options for how to charge new solar Net Energy Metering (NEM) customers for power services.

The main research issues are:

- Understand current levels of knowledge regarding how customers who install their own solar pay for or are charged for solar electricity
- Test four different potential solar rate plan structures that could be offered to new solar customers (via a conjoint choice task experience)
  - Understand what aspects of each are appealing, and which factors cause customers to prefer a different option
- Determine what are the perceived benefits & drawbacks of the different ways to be charged
- Understand any key differences among demographic groups, segments, or situation variables that influence choice and preferences

Methodology

HINER & Partners conducted an online survey in June 2015 among SDG&E customers with an interest in adding or learning more about solar electric power for their home.

- Respondents were from online panels provided by Research Now and EMI that were pre-screened by zip code to match SDG&E's service footprint
- Respondents were further screened to meet the following criteria:
  - Homeowner of a single family detached or attached (duplex, townhouse) residence
  - Do not currently have solar (or wind) power
  - Household decision maker for making improvements (such as adding solar) and paying the SDG&E bill (electric or electric/gas, no gas only)
  - Not employed by a utility, solar company, or marketing agency (market research, advertising, or public relations)
  - Have positive interest (7 or higher on a 10-point scale) in either learning more about or installing solar for their home

Methodology

The margin of error and difference needed for significance are shown in the table below for various sample sizes.

Sample Size	Margin of Error*	Difference Needed for Significance**
65	+/- 10.2%	+/- 14.4%
150	+/- 6.7%	+/- 9.5%
250	+/- 5.2%	+/- 7.4%
400	+/- 4.1%	+/- 5.8%
500	+/- 3.7%	+/- 5.2%

* 90% confidence at 50% proportion level

** When comparing between subgroups each with sample size indicated

Respondent Screening: Interest in Solar

➢ Customers were screened for interest in learning more about solar electricity for their home, and for installing solar electricity in their home.

- Interest in learning more about solar is stronger than interest in installing solar – which makes sense since knowledge usually precedes intentions.
- In the report, "highly interested" rated 8-10 for both questions, with the remainder labeled "moderately interested."

	Interested in Learning More About Solar for Home	Interested Homeowners (n=417) a
Highly interested = 8-10 for both questions	8-10	80%
	10	28%
	9	17%
	8	35%
	7	10%
Qualification = 7 or above for either question	6	7%
	5	1%
	4	-
	3	<[VALUE]
	2	-
	1	-
	Not Sure	1%

Interested in Installing Solar in Home	Interested Homeowners (n=417) a
8-10	65%
10	21%
9	15%
8	29%
7	17%
6	10%
5	5%
4	1%
3	1%
2	<[VALUE]
1	<[VALUE]
Not Sure	1%

QS7: "How would you rate your current interest in learning more about solar electricity for your home? Use the following 10-point scale where 10 means you are extremely interested and 1 means you are not at all interested?"
QS8: "And how would you rate your current interest in installing solar electricity in your home?"

Awareness and interest in solar, beliefs about solar, susceptibility to serious consideration of solar, profiles of homeowners with high interest

Executive Summary

Executive Summary

- Homeowners interested in solar have only modest favorability toward SDG&E. As a result, some of them did view the solar rate options with skepticism (based on their verbatim comments about the options).
  - Also, interested homeowners' prior knowledge about how solar customers are charged is relatively accurate, despite that only a minority recalled hearing about or learning about solar rates in the past. So, while some customers were confused by some of the rate option descriptions, most apparently understood the main aspects and were able to evaluate them from a relatively informed perspective.
- Based on paired comparison choices, Feed-In-Tariff/VOS is preferred by a majority (63%) of solar interested homeowners.
  - Demand Charge (preferred by 17%) is a distant second, followed closely by Installed Capacity Charge (13%). Panel Rate was the least preferred at 7% - which is only about half the preference of the third place option.
  - These preference rankings reflect that the Feed-In-Tariff/VOS is associated by customers with more of the choice factors, and particularly those that are more important to customers. These include: "saves money," "fair," and "simple." A less important factor with higher association with the Feed-In-Tariff/VOS is "understandable."
  - Conversely, the Panel Rate has much lower association with the more important factors.

Executive Summary

- Each of the four options have pros and cons from the customer perspective, based on customers' verbatim comments (coded and summarized) about each.

- Feed-In-Tariff/VOS
  - Pros: Can save money (by lowering usage), easy to understand, fair
  - Cons: Unpredictable (may pay more), confusing, unfair (not charged for actual use)
- Demand Charge
  - Pros: Can save money (through changing behavior), gives control over the bill
  - Cons: Can be difficult to change behavior, unpredictable (may pay more), confusing
- Installed Capacity Charge
  - Pros: Consistent (bill does not change), easy to understand (and budget)
  - Cons: Unfair (not charged for actual usage), confusing
- Panel Rate
  - Pros: Consistent (bill doesn't change), can save money, easy to understand
  - Cons: Unfair (not charged for actual usage), confusing, doesn't encourage conservation

Executive Summary

- Bill payment, household characteristic, and demographic differences between customer groups who preferred each of the four solar rate plan options are relatively minor.
- Customers who prefer… <u>Feed-In-Tariff/VOS</u>
  - Read their bills more closely than others, especially looking at the dollar amount of electric and gas separately, reading notes and messages, and looking at gas usage
  - Are older (median is 56-65 years vs. 46-55 years for other rate plan preference groups)
- <u>Demand Charge</u>
  - Have the smallest avg. bill amounts, summer ($132 vs. $160+) and winter ($107 vs. $150+)
  - Are more likely in smaller, older homes
- <u>Installed Capacity Charge</u>
  - Are more likely in single family detached (rather than attached) homes
  - Are more likely on a Level Pay Plan, but less likely to have My Account online access
  - Are more likely full-time employed
- <u>Panel Rate</u>
  - Have the largest avg. summer bill amounts ($195 vs. $132 - $163)
  - Are more likely in all electric, single family attached homes
  - Have more people living in the home (4+)

Satisfaction with SDG&E rate attributes

Overall favorability of SDG&E

Overall Evaluations of SDG&E

Homeowners Interested in Solar

Customer Satisfaction with Rates

- Among solar interested homeowners, SDG&E received modest ratings for overall favorability (30% rated 8-10, mean was 5.8), and ratings slightly below that for all but one of the pricing attributes.
  - Those who are highly interested rated SDG&E significantly higher across all of the statements – its possible that interest in solar is facilitated by a more optimistic or favorable view of SDG&E, perhaps because most consumers believe they still need to be connected to the grid.

Measure % 8-10	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Communicating rate changes in a timely manner	33%	39% c	24%
Educating you on the benefits of different rate options	24%	29% c	16%
Providing value added services	23%	27% c	16%
Availability of rate options to suit your specific needs	25%	31% c	16%
Charging a fair price for electricity services	19%	23% c	13%
Overall favorability towards your electric company	30%	34% c	23%

Letters indicate a significant difference at the 90% confidence level for columns B & C

Q1.1: "Using a 10-point scale, where 1 means you are extremely dissatisfied, and 10 means you are extremely satisfied, how would you rate your satisfaction with your electric company when it comes to ... ?"
Q1.2: "Using a 10-point scale where 1 means your feelings are not at all favorable and 10 means your feelings are extremely favorable, how would you rate your favorability towards your electric company?"

Current involvement in solar

recentness of involvement in solar

Knowledge of solar rates

Choice factor preferences

Knowledge About Solar Rates

Homeowners Interested in Solar

Current Involvement in Solar

➢ Most of the interested homeowners who completed the survey (80%) have taken some type of overt action regarding solar, either by talking to others about it, searching the Internet for information, or talking and getting bids from contractors.

- Relatively few, though, spoke to SDG&E about it, indicating that SDG&E is not considered a primary source of information on solar. Long term, this is a perception that SDG&E might want to turn around.
- The "highly interested" are somewhat more likely to have taken action.

Actions Taken	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Took an Action	**80%**	**83% c**	**74%**
Spoke to friends, neighbors, relative or co-workers	**54%**	60% c	44%
Searched Internet for Information	**45%**	49% c	37%
Spoke with or contracted a Solar contractor	**28%**	30%	24%
Requested or received a bid	**15%**	17%	12%
Went to electric utility website, sdge.com	**11%**	12%	10%
Spoke with or contacted SDG&E	**8%**	9%	6%
Installed solar somewhere else	**3%**	3%	3%
None of these actions	**19%**	**16%**	**25% b**
Not sure	**1%**	**1%**	**1%**

Q2.1: "Which of the following describes your current involvement with solar electric power for your home?"
Letters indicate a significant difference at the 90% confidence level for columns B & C

recentness of Involvement in Solar

➢ The recentness of actions taken ranged widely, though nearly all have taken action within the past year, and a majority have done something within the past 3 months.

- The "highly interested" are more likely to have taken more recent action, confirming that their interest in not just idle curiosity.

recentness of Action	Interested Homeowners Who Took Action (n=332) a	Highly Interested (n=214) b	Moderately Interested (n=118) c
1 month or less	**21%**	25% c	14%
2 months	**19%**	21%	15%
3 months	**16%**	15%	18%
4-6 months	**18%**	18%	19%
7-12 months	**13%**	12%	14%
More than 12 months	**10%**	7%	14% b
Not sure	**3%**	3%	4%

Q2.2: "How many months ago did you take your most recent action regarding solar electric power for your home?"
Letters indicate a significant difference at the 90% confidence level for columns B & C

Knowledge of Solar Rates

➢ About one in three (37%) who have taken some type of action said they have heard or learned about how SDG&E will charge them if they add electric power to their home.

- The difference between the highly and the moderately interested is minor.
- Customers who know something about how they'll be charged mentioned saving money, earning a credit for selling excess power back, and charges for access to the grid and for grid power. Overall, unaided knowledge is relatively low.

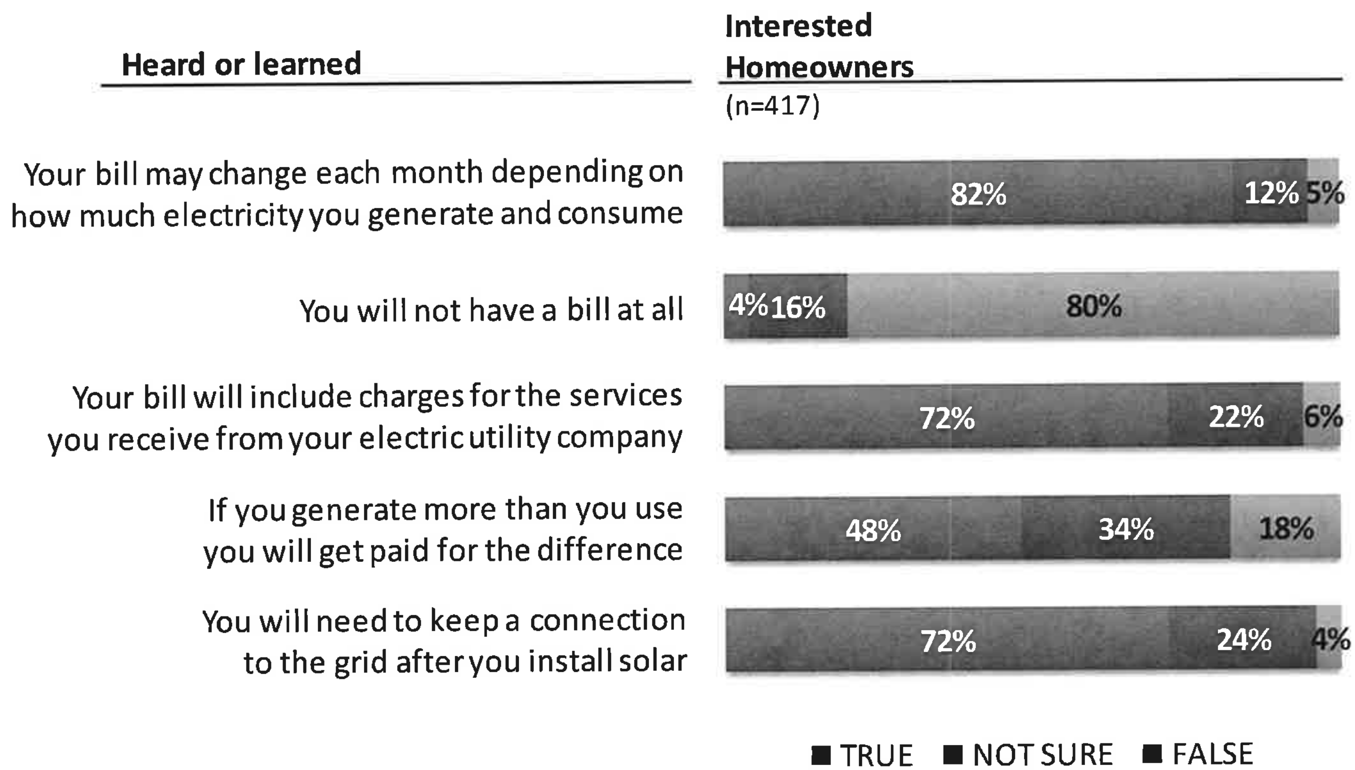
Heard or learned how SDG&E will charge you for solar	Interested Homeowners Who Took Action (n=332) a	Highly Interested (n=214) b	Moderately Interested (n=118) c
Yes	37%	39%	35%
No	52%	51%	52%
Not sure	11%	10%	14%
What do you know about it			
It will save me money	21%	22%	20%
Credit for excess power generated	15%	12%	20%
Have to pay a fee	14%	16%	10%
Charged for using power from the grid	11%	10%	15%
Policy / rates may change	7%	8%	5%
Other	20%	22%	17%
Don't know / Nothing	12%	11%	15%

Letters indicate a significant difference at the 90% confidence level for columns B & C

Q2.3: "Have your heard or learned anything about how your electric utility will charge you if you add solar electric power to your home?"
Q2.4: "What do you know about how your electric utility company will charge you if you add solar electric power to your home?"

Knowledge of Solar Rates

- All survey respondents were asked to evaluate five statements as true or false. On an aided basis, a majority of solar interested homeowners do understand main aspects of SDG&E's current solar rates: (1) their bill could vary month to month depending on their generation and usage, (2) they'll still have a bill from SDG&E, (3) the bill will include charges for SDG&E services, and (4) they'll keep a connection to the grid.
  - Customers were less clear about getting paid if they generate more than they use.



Q2.5: "Which of the following do you believe to be true after installing solar power to your home? You can select more than one as true?"

Choice Factor Preferences

- Importance of choice factors are shown below. "Saves money" was most important, followed by "simple," "fair," "works for me," and "predictable."
  - After "saves money," differences were not too substantial, indicating that customers have a variety of choice factor preferences.
  - The "highly interested" values "stable" more than the moderately interested.

Choice Factors (% Top 3)		Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	57%	57%	57%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	39%	41%	35%
Fair	Seems like a fair way to be charged for energy.	34%	33%	35%
Works for Me	Fits my habits and lifestyle.	34%	32%	38%
Predictable	I know about how much my bill amount should be each month.	33%	34%	32%
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	28%	27%	31%
Understandable	In language I can understand.	28%	27%	28%
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	28%	31% c	23%
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	20%	19%	23%

Q2.6: "If you were comparing electric rate plans, what would be the most important factors you would consider in choosing the plan for your household? Please choose the three most important factors from the following list?"
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option A: Demand Charge

Rate Option B: Installed Capacity Charge

Rate Option C: Feed-In-Tariff/VOS

Rate Option D: Panel Rate

Solar Rate Plan Options

Homeowners Interested in Solar

Background

Respondents read the following text prior to answering questions about four rate options:

"Your electricity bill is divided into two main types of charges:

- **Generation charges** reflect the cost to generate the electricity that you use. When you install solar panels on your home, the electricity that your solar system generates offsets the generation services you need from the utility. This helps reduce your overall utility bill.
- **Delivery charges** reflect the cost to deliver electricity to your home, which includes the pipes and wires necessary to get the electricity there. While solar generation will offset your need for Generation services from the utility, you will continue to need Delivery services from the utility to ensure the delivery of electricity to meet your needs during the evening (when your solar system is not generating). In addition, during the day your solar system may generate more than you need and utility Delivery services enable you to export any excess generation from your generation from your solar system back to the utility.

In the future, SDG&E customers who choose to add solar electric power could be billed differently than the way solar customers are billed today. There are four different ways that are under evaluation for how you could potentially be billed as a solar customer. **These options mainly focus on changes to the Delivery charges on your bill.**

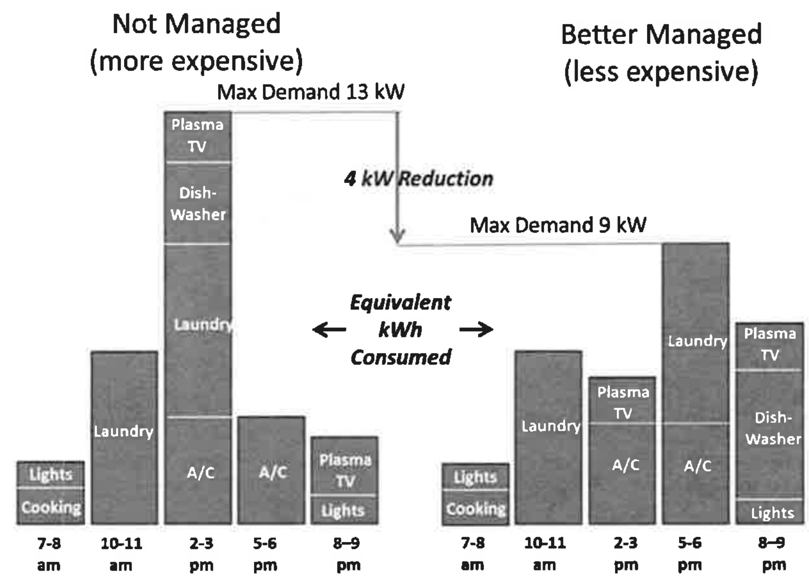
Keep in mind that your electric utility company will not earn more money from one plan over another. Also, with all four plans, you will have the ability to lower your bill by lowering your usage. Descriptions of each are detailed next.

Rate Option A: Demand Charge

"Your electricity bill is divided into two main types of charges:

On this type of solar rate plan, you are billed according to your **monthly demand for Delivery services**. What is "demand"? Demand **is not** based on how much energy you use over the month. **Demand *is* based on how many things you have on at the same time.** Your solar generation would offset your need for Generation services from the utility on your bill.

Your demand can vary greatly from month to month. You can keep your demand low by spreading out the number of things you have on at a given moment in time. For example, the chart below shows how maximum demand can be lowered by spreading out activities such as laundry and dishwashing to other times of the day. (Note: the values below are just illustrative and not actual numbers)."



Actual, relative and temporal demand per end-use is illustrative and will vary based on appliance model, when you are home, and other factors.

Rate Option A: Demand Charge

"Your maximum demand will be the highest amount of electricity usage during any one hour period during the month. Your monthly bill will be calculated using your maximum demand during that month. If you have an hour where you are running a lot of appliances at once, your maximum demand during that month could be higher.

On this plan, the billed amount for the delivery charges on your bill could change from month to month. If you are able to lower your demand, the delivery charges on your bill would be lower."

Demand Charge $ / kW	Maximum Demand	Billed Amount
$8	*7 kW*	*$56*
$8	*4 kW*	*$32*

Rate Option A: Demand Charge

- Option A "Demand Charge" was perceived to "save money," be "understandable," "simple," and "fair," with "saves money" being very prominent.
  - The moderately interested felt this option was "understandable" and "simple" more than the highly interested, who were more likely to say it "reflects cost of service."

Applicable Choice Factors (% Applicable) (in order of importance)		Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	59%	57%	64%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	24%	21%	29% b
Fair	Seems like a fair way to be charged for energy.	22%	19%	26%
Works for Me	Fits my habits and lifestyle.	17%	16%	18%
Predictable	I know about how much my bill amount should be each month.	11%	11%	10%
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	9%	11% c	6%
Understandable	In language I can understand.	28%	25%	34% b
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	8%	8%	8%
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	7%	7%	8%

Q3.1a: "After reading about this plan, which of the following terms below would you say best describes this way of being billed for solar electricity services? (Choose all that apply)"
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option A: Demand Charge

- Verbatim comments about the Demand Charge option are summarized below. The top positives are that it can save money, gives the customer control, and is easy to understand.
  - Negatives are that it could be difficult to change habits, it's not predictable, and it's confusing.

Like Most (comments)	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Can save me money	25%	27%	22%
Can control bill / usage	15%	13%	18%
Easy to understand	10%	10%	9%
Charged for use based on demand	4%	5%	4%
Good / I like it	4%	5% c	2%
Fair	3%	3%	4%
Reduce usage / Help the environment	3%	2%	6%
Other	12%	13%	12%
Don't know / Nothing	28%	25%	31%
Like Least (comments)			
Can't change habits / Difficult to manage	23%	19%	28% b
Unpredictable / May pay more	13%	12%	15%
Confusing	12%	14%	11%
Bad / I don't like it	8%	9%	7%
Unfair / Not charged for actual usage	8%	5%	11% b
Other	9%	10%	8%
Don't know / Nothing	27%	31% c	21%

Q3.2a: "What do you like most about this plan? Please give specific details."
Q3.3a: "What do you like least about this plan? Please give specific details."
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option A: Demand Charge

- A sample of actual verbatim comments are shown here:

Like Most (comments)

"I think it is easy to understand and make immediate efforts to change behaviors."
"It is easy to understand and encourages me to not use a lot of appliances at once."
"the consumer can control costs by spreading out energy usage throughout the day."
"The ability to make your bill lower."
"it would help savings in the long run when using the right amount in time."
"Seems fair giving me ability to alter my bill by changing behavior."
"This makes me feel that both electric and solar companies care about helping everyone lower their energy bill."
"It gives options."
"Makes you more aware of energy use."

Like Least (comments)

"I don't like anything about it. I will constantly have to monitor how many electric appliances are being used at each time, and will have to become the "electricity police" in my household and make sure that each family member is complying."
"You need to add "As usual, San Diego Gouge and Extortion is SO afraid they will lose some money" because with so many people adding solar, all of these options sound like SDG&E wants to rip us off as usual! So, with THIS plan, I come home from work and it is really hot, so I turn on the air, but now can't cook dinner on the stove. SUCKS."
"Too complicated to understand."
"It punishes you for using everything at once like they have asked for late evening to conserve energy during peak use."
"Don't like having to change behaviors. Don't like getting charged based on the maximum demand."
"Requires more attention to detail if I want to save money."
"It takes planning and is not practical for a family. I need to do laundry and run the dishwasher when I'm home."

Q3.2a: "What do you like most about this plan? Please give specific details."
Q3.3a: "What do you like least about this plan? Please give specific details."

Rate Option B: Installed Capacity Charge

"For this next type of solar rate plan, you are billed according to the **size of your solar system for the Delivery services**. Your solar generation would offset your need for Generation services from the utility on your bill.

For example, if you install a 4kW solar system, and your rate is $8 per KW (a hypothetical amount), the Delivery charges on your bill will be $32 ($8 X 4KW).

The decision of what size solar system to install generally depends on how much electricity you typically use.

On this plan, the delivery charges on your bill **will not change from month to month**. If you change how you use energy, i.e., lower your maximum demand, the delivery charges on you bill will be the same."

Rate Option B: Installed Capacity Charge

- Interested homeowners felt Option B "Installed Capacity Charge" was "predictable," "stable," "understandable," "worry free," and "simple." Association is relatively low for the factors that are higher in importance. Also, moderately interested customers were more likely to apply "simple" to this option than the highly interested.

Applicable Choice Factors (% Applicable) (in order of importance)		Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	13%	14%	13%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	26%	23%	31% b
Fair	Seems like a fair way to be charged for energy.	15%	15%	14%
Works for Me	Fits my habits and lifestyle.	12%	12%	11%
Predictable	I know about how much my bill amount should be each month.	41%	38%	44%
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	16%	17%	14%
Understandable	In language I can understand.	27%	26%	28%
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	35%	34%	38%
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	27%	29%	25%

Q3.1b: "After reading about this plan, which of the following terms below would you say best describes this way of being billed for solar electricity services? (Choose all that apply)"
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option B: Installed Capacity Charge

- Verbatim comments about the Installed Capacity Charge option are summarized below. The top positives are that the bill would be consistent (from month to month) and it's easy to understand.
  - Negatives are not being charged for actual usage (some consider this unfair), and that it's confusing.

Like Most (comments)	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Consistent / Bill doesn't change	34%	33%	34%
Easy to understand	11%	11%	11%
Good / I like it	6%	6%	6%
Can save money	5%	7% c	2%
Fair	3%	4%	2%
Reduce usage / Help the environment	<[VALUE]	<1%	-
Other	10%	10%	11%
Don't know / Nothing	31%	29%	35%
Like Least (comments)			
Unfair / Not charged for actual usage	19%	18%	23%
Confusing	12%	14% c	9%
Bad / I don't like it	7%	8%	7%
Unpredictable / May pay more	6%	6%	7%
Doesn't encourage conservation	5%	4%	5%
Lack of control	5%	5%	4%
Can't change habits	2%	1%	3%
Other	9%	9%	11%
Don't know / Nothing	34%	35%	33%

Q3.2b: "What do you like most about this plan? Please give specific details."
Q3.3b: "What do you like least about this plan? Please give specific details."
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option B: Installed Capacity Charge

➢ A sample of actual verbatim comments are shown here:

Like Most (comments)

"Delivery charge would be constant."
"This plan makes it clear that it would be best to do research with an honest company about the best panel array to install, based on the household. I can appreciate that."
"My home is generating this energy why couldn't I just use what I want and not have to worry about my bill changing each month."
"You know up front what the delivery charge will be."
"It's the simplest one to understand and the fairest one."
"A flat rate is easier to understand and usually evens out in the long run regarding fluctuations in behavior and usage."
"Easy to budget for energy costs."
"It sets a rate charge that is consistent and reliable."

Like Least (comments)

"What if a user has a large system but does not need all the extra capacity. It encourages people to get small systems that may not fully address their needs."
"Not sure how "fair" it would be."
"It doesn't offer any incentive to change the way you use energy."
"Initial capital investment is a poor metric."
"Penalizes someone for getting a system that generates more solar energy."
"I dislike that this will charge me for having a solar system installed, which defeats the purpose of installing it: which should be energy savings. Why would I want to pay to rent a system from the utility?"
"Unpredictability. With the delivery charge being consistent, I must rely on monitoring my own usage and on the solar generation offsetting that usage. I feel that if I end up not offsetting my usage, I could potentially pay more."
"I don't like that I can't impact my electric bill after I have installed my solar system; I get to decide the size of it before it's installed, but after that, I've lost practically all control over my bill."

Q3.2b: "What do you like most about this plan? Please give specific details."
Q3.3b: "What do you like least about this plan? Please give specific details."

Rate Option C: Feed-In-Tariff/VOS

"On this type of solar rate plan, you will receive a payment from the utility for all of the electricity your solar system generates, at a pre-determined price. Your home will not actually use the electricity generated by your solar system. You will continue to pay for Delivery and Generation services for your household usage. And the payment for your solar generation will be reflected as a credit on your bill.

Your bill will include the credit for your generated electricity, plus the charges (which will include charges for Delivery and Generation services) for the electricity you used during the month.

On this plan, rather than having your solar generation offset your need for Generation services from the utility, you will receive a credit based on the generation from your solar system. So the credits to your bill could change from month to month, depending on how much your system generates and how much electricity you use."

Rate Option C: Feed-In-Tariff/VOS

➢ Option C "Feed-In-Tariff/VOS" had more diffuse but still relatively strong association with several of the more important factors: "fair," "saves money," "understandable," and "simple."

- There are no differences in association here between the highly and the moderately interested customers.

Applicable Choice Factors (% Applicable) (in order of importance)		Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	36%	38%	33%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	28%	28%	28%
Fair	Seems like a fair way to be charged for energy.	37%	35%	39%
Works for Me	Fits my habits and lifestyle.	18%	18%	17%
Predictable	I know about how much my bill amount should be each month.	12%	13%	11%
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	18%	17%	19%
Understandable	In language I can understand.	33%	32%	33%
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	11%	12%	11%
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	15%	14%	18%

Q3.1c: "After reading about this plan, which of the following terms below would you say best describes this way of being billed for solar electricity services? (Choose all that apply)"
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option C: Feed-In-Tariff/VOS

- Verbatim comments about the Feed-In-Tariff/VOS option are summarized below. The top positives are that it can save the customer money, it's easy to understand, and it's fair.
  - Main negatives are that it's unpredictable (some months the customer could pay more) and it's confusing.

Like Most (comments)	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Can save money	31%	32%	29%
Easy to understand	13%	12%	15%
Fair	12%	10%	14%
Consistent / Bill doesn't change	5%	5%	4%
Good / I like it	4%	6% c	1%
Can control bill / usage	4%	4%	4%
Reduce usage / Help the environment	2%	2%	2%
Other	7%	7%	6%
Don't know / Nothing	24%	23%	25%
Like Least (comments)			
Unpredictable / May pay more	17%	17%	16%
Confusing	15%	12%	19% b
Unfair / Not charged for actual usage	7%	7%	9%
Bad / I don't like it	3%	3%	2%
Lack of control	2%	3%	2%
Can't change habits / Too difficult to manage	2%	1%	3%
Other	18%	21%	17%
Don't know / Nothing	36%	38%	32%

Q3.2c: "What do you like most about this plan? Please give specific details."
Q3.3c: "What do you like least about this plan? Please give specific details."
Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option C: Feed-In-Tariff/VOS

- A sample of actual verbatim comments are shown here:

Like Most (comments)

"Will be given bill showing how much my system generated."
"it keeps the 'ins" and the "outs" bundled into as few places as possible, which should make it easier to keep track of and understand the charges listed on the bill at the end of the month."
"Honestly, I like the assurance that I would still be receiving traditional electricity. It seems like with this option, the re would be no second-guessing if a low sun period might reduce my access to services, or guessing much about pricing if the offset rate is predetermined. This seems like an easy way to incorporate solar."
"Ability to save by lowering usage."
"Payment for generated solar electricity."
"I like that I can still receive credit. I like that my bill would be lower and that this type of service is geared towards someone like me."

Like Least (comments)

"Seems like it could be a way to overcharge the customer without them knowing it. Opens up the door for corruption and fraud."
"I am not cutting back on dependency to SDG&E."
"I would have to pay delivery and generating fees and only the electricity I sell to the electricity company will be credited."
"The unknown rate."
"Without looking at real numbers, I don't know whether the rate the electrical company will be crediting me will be a fair rate or not without knowing if they will be crediting me at the same rate that they charge me."
"it might be challenging for some households to have a varied charge for energy each month."
"Requires more monitoring to understand variations."
"no way to check electric company figures."

Q3.2c: "What do you like most about this plan? Please give specific details."
Q3.3c: "What do you like least about this plan? Please give specific details."

Rate Option D: Panel Rate

For this next type of solar rate plan, you are billed according to the **size of your electrical circuit panel for Delivery services**. Your electrical circuit panel is the point of interconnection between your house and the electric utility grid. Your solar generation would offset your need for Generation services from the utility on your bill.

On this type of plan, you will be billed for Distribution Services based on the **total amount of electricity you could *potentially* use.**

The size of your electrical circuit panel determines how much electricity your home can handle. Have you ever blown a fuse in your home? This is because you temporarily used more electricity than your panel would allow.

The size, age of your home, or amount of electricity you typically use are factors in what size electric circuit panel you have. However, most homes today have the same panel size.

On this plan, the delivery charges on your bill **will not change from month to month**. If you use more electricity during the month, or less electricity, while you generation charges may change, you will always have the same delivery charges on your bill.

Rate Option D: Panel Rate

➢ Option D "Panel Rate" was associated more so with the less important choice factors, including "stable," "predictable," "understandable," "simple," and "worry free."

- The moderately interested have higher association with stable for this option than do the highly interested.

Applicable Choice Factors (% Applicable) (in order of importance)		Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	11%	12%	11%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	26%	23%	29%
Fair	Seems like a fair way to be charged for energy.	9%	11%	7%
Works for Me	Fits my habits and lifestyle.	8%	8%	8%
Predictable	I know about how much my bill amount should be each month.	34%	33%	34%
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	13%	14%	11%
Understandable	In language I can understand.	28%	30%	24%
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	38%	33%	46% b
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	26%	26%	27%

Q3.1d: "After reading about this plan, which of the following terms below would you say best describes this way of being billed for solar electricity services? (Choose all that apply)"

Letters indicate a significant difference at the 90% confidence level for columns B & C

Rate Option D: Panel Rate

- Verbatim comments about the Panel Rate option are summarized below. The top positives are that it's consistent, it can save the customer money, and it's easy to understand.
  - Main negatives are that it's unfair for not charging for actual use, it's confusing, and it doesn't encourage conservation.

Like Most (comments)	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c
Consistent / Bill doesn't change	34%	33%	34%
Can save money	7%	8%	7%
Easy to understand	7%	6%	8%
Can control bill / usage	4%	3%	6%
Fair	4%	5%	3%
Good / I like it	3%	4%	2%
Reduce usage / Help the environment	2%	2%	3%
Other	5%	5%	5%
Don't know / Nothing	38%	38%	37%
Like Least (comments)			
Unfair / Not charged for actual usage	36%	33%	41%
Confusing	12%	14% c	9%
Doesn't encourage conservation	8%	7%	9%
Bad / I don't like it	4%	4%	4%
Unpredictable / May pay more	3%	2%	5%
Lack of control	1%	<1%	2%
Can't change habits	1%	1%	1%
Other	10%	10%	11%
Don't know / Nothing	27%	30% c	23%

Letters indicate a significant difference at the 90% confidence level for columns B & C

Q3.2d: "What do you like most about this plan? Please give specific details."
Q3.3d: "What do you like least about this plan? Please give specific details."

Rate Option D: Panel Rate

➢ A sample of actual verbatim comments are shown here:

Like Most (comments)

"It closely correlates to what I can produce energy wise."
"Easy to understand. Predictable."
"Well, it sounds good and that is what scares me. If it would actually save me money and help the environment then I would say great."
"You know what your monthly charge is."
"Most homes will have similar charges based on the size of their circuits."
"Flat rate bill."
"I like that there won't be any surprise fees."
"I have a smaller house so this option might be the best one."
"Will not cause my bill to change a lot from month to month, or from season to season."

Like Least (comments)

"I don't like it. It stays the same no matter what I use!!!!."
"I do not like this plan at all, there seems to be little motivation to conserve."
"I'm not sure about the potential use charges and how that would work."
"I don't like the idea of being charged for electricity that I would *potentially* use based on size of panel. It just seems unfair."
"Paying for availability of capacity instead of actual usage."
"Process of charging seems difficult to understand."
"Charging the same amount regardless of the amount of electricity used."
"No incentive to conserve electricity, not really fair if not using all the electricity possible."
"I live in a large house by myself with a large panel that would *** **** me for services."
"Hate everything about it: allows for NO savings based on individual conservation efforts."
"You pay for what you do or don't use."

Q3.2d: "What do you like most about this plan? Please give specific details."
Q3.3d: "What do you like least about this plan? Please give specific details."

Summary: Applicable Choice Factors

- The chart below directly compares the choice factors across the four rate options.
  - Demand Charge and Feed-In-Tariff/VOS stand out for "saves money."
  - Feed-In-Tariff/VOS also stands out for "fair" and "understandable," and is identified more than the other options for "simple," "works for me," and "reflects cos of service."
  - Both Installed Capacity Charge and Panel Rate are considered "predictable" and "stable."

Applicable Choice Factors (% Applicable) (in order of importance)		Option A Demand Charge	Option B Installed Capacity	Option C Feed-In-Tariff/VOS	Option D Panel Rate
Saves Money	Provides opportunity to save even more money on my bill by changing my energy use behavior.	59% bcd	13%	36% bd	11%
Simple	Does not require a lot of effort to understand how my energy use behavior will affect my bill.	24%	26%	28%	26%
Fair	Seems like a fair way to be charged for energy.	22% bd	15% d	37% abd	9%
Works for Me	Fits my habits and lifestyle.	17%	12%	18%	8%
Predictable	I know about how much my bill amount should be each month.	11%	41% acd	12%	34% ac
Reflects Cost of Service	Charges me about the same amount that it actually costs my electric utility company to provide service.	9%	16% a	18% ad	13%
Understandable	In language I can understand.	28%	27%	33%	28%
Stable	Will not cause my bill to change a lot from month to month, or from season to season (winter / summer).	8%	35% ac	11%	38% ac
Worry-Free	I don't need to pay attention to when during the day or month I use energy.	7%	27% ac	15%	26% ac

Letters indicate a significant difference at the 90% confidence level

Rate Option Choice Tasks: Conjoint

"Now we're going to show you pairs of the different solar rate plans, and ask that you choose the one solar rate plan that you prefer more than the other, assuming that you will add solar electric power in the future. These rate plan configurations are the same ones you've just reviewed.

Note that these different solar rate plans are not rate increases, but merely different ways of billing you for electricity. Again, keep in mind that your electric utility company will not earn more money from one plan over another. The four options **mainly focus on changes to the Delivery charges on your bill.** You will have the ability to lower your total bill by lowering your usage under the different options."

Which solar rate plan would you choose?

(6 of 6)

Billed for Delivery services according to monthly demand. Demand is based on how many devices you have on at the same time. This billing could vary from month-to-month. (Click here to see the full rate description.)	Billed for Delivery services based on the size of your solar system. The size of your solar system will depend on how much electricity you typically use. This billing does not vary month-to-month. (Click here to see the full rate description.)
○	○

0% 100%

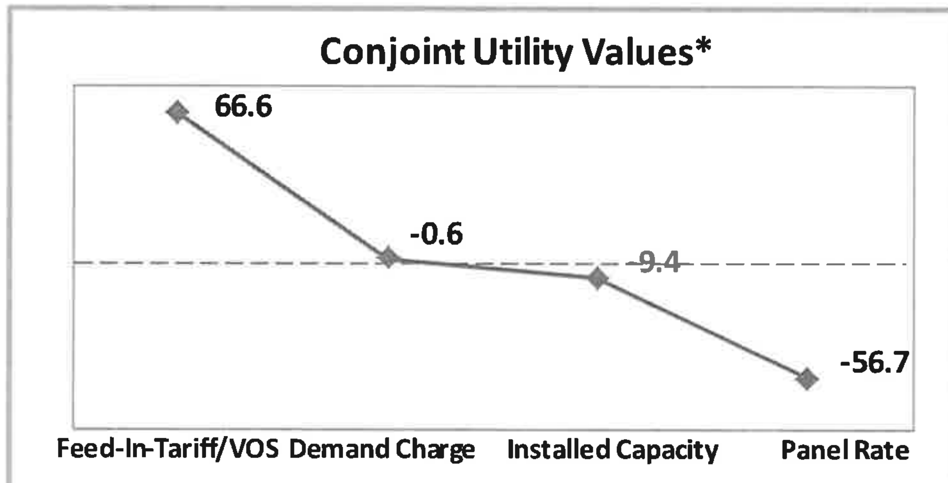
Click here to see our privacy policy

Rate Option Choice Task Results

➢ Based on paired comparison choices, the Feed-In-Tariff/VOS is preferred by a majority (63%) of solar interested homeowners.

- Demand Charge (preferred by 17%) is a distant second, followed closely by Installed Capacity Charge (13%). Panel Rate was the least preferred at 7% - which is only about half the preference of the third place option.
- These preference rankings reflect that the Feed-In-Tariff/VOS is associated by customers with more of the choice factors, and particularly those that are more important to customers. Conversely, the Panel Rate is associated much less with the more important factors.
- The Conjoint Utility Values also reflect strong preference for the Feed-In-Tariff/VOS, followed distantly by Demand Charge and Installed Capacity, and with Panel Rate

	Options	Share of Preference
C	**Feed-In-Tariff/VOS**	63
A	**Demand Charge**	17
B	**Installed Capacity Charge**	13
D	**Panel Rate**	7



*Conjoint Utility Values are estimates of preference normed around 0. Share of preference is derived from these to show an estimate of the percentage of customers who would choose each option if presented with all four

Rate Option Choice Task Results

➢ The tables below show the estimated share of preference in head-to-head comparisons between each combination of the four options, which assumes only two options are available and customers have to pick one.

- Feed-In-Tariff/VOS is preferred by 3:1 compared to Demand Charge (76% would choose Feed-In-Tariff/VOS vs. 24% would choose Demand Charge). Full Buy Sell is preferred by 4:1 over Installed Capacity Charge and 6:1 over Panel Rate.
- Demand Charge edges Installed Capacity Charge by about 4:3.
- Panel Rate's highest share is only 30%, against Demand Charge.

	Options	Share of Preference
C	**Feed-In-Tariff/VOS**	76%
A	**Demand Charge**	24%
C	**Feed-In-Tariff/VOS**	79%
B	**Installed Capacity Charge**	21%
C	**Feed-In-Tariff/VOS**	85%
D	**Panel Rate**	15%

	Options	Share of Preference
A	**Demand Charge**	57%
B	**Installed Capacity Charge**	43%
A	**Demand Charge**	70%
D	**Panel Rate**	30%
B	**Installed Capacity Charge**	74%
D	**Panel Rate**	26%

Current method for receiving the SDG&E bill

Bill review habits

Bill Review Habits and Bill Amounts

Homeowners Interested in Solar

Method of Receiving SDG&E Bill

- About half of the interested homeowners who participated in the survey receive their bill online (via an email notification).
  - Since the survey was completed through the web, this probably overstates the actual percentage of SDG&E customers who participate in online billing.
  - Rate plan preference is not related to the customer's bill receipt method.

		Level of Interest		Rate Plan Preference			
Bill Receipt Method	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
Online	45%	45%	44%	47%	40%	45%	38%
Mail	54%	54%	54%	52%	60%	53%	62%
Other	< 1%	<1%	<1%	-	-	1%	-
Not Sure	1%	1%	1%	2%	-	1%	-

Q6.1: "How do you currently receive your monthly electric bill?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Bill Review Habits

- Nine out of ten (88% of interested homeowners) said they look at the amount due and due date. Another two in three look at separate dollar amounts of electric and gas, and their electricity use (kWh).
  - Both the highly and moderately interested have similar bill review habits.
  - Customers who preferred Feed-In-Tariff/VOS read their bills more closely than others, especially looking at the dollar amount of electric and gas separately, reading notes and messages, and looking at gas usage.

		Level of Interest		Rate Plan Preference			
Bill Review Actions	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c	Demand Charge (n=64) d	Installed Capacity Charge (n=47) e	Feed-in Tariff/VOS (n=285) f	Panel Rate (n=21) g
Look at amount due and/or due date	88%	88%	89%	91%	87%	89%	81%
Look at $ amount of electric & gas separately	61%	60%	63%	55%	47%	66% eg	43%
Look at actual electricity or kwh usage	60%	60%	59%	56%	53%	62%	48%
Read notes or other messages on the bill	45%	44%	47%	44% e	26%	49% b	38%
Look at actual gas or therm usage	40%	40%	39%	38% g	32%	43% g	19%
Read the details about how bill is calculated	33%	33%	33%	28%	38%	33%	33%
Read any inserts that are included with the bill	29%	29%	29%	27%	28%	31%	19%
None – you don't look at bill	3%	3%	3%	-	2%	3% d	10%
Not sure	1%	1%	1%	3%	-	<1%	-

Q6.2: "When you review your monthly electric bill, which of the following do you typically do?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Average Summer Electric Bill

- Interested homeowner's self-reported average summer electric bill amounts are shown here, divided into approximate quartiles. The median bill average summer bill is $115, and the mean is $159.
  - Highly interested have only slightly higher bills than the moderates. Both groups are similar for knowing about their tiers. Bill amounts vary by rate plan preference too, with Demand Charge having the lowest.

		Level of Interest		Rate Plan Preference			
Average Monthly Summer Electric Bill	**Interested Homeowners**	**Highly Interested**	**Moderately Interested**	**Demand Charge**	**Installed Capacity Charge**	**Feed-in Tariff/VOS**	**Panel Rate**
	(n=417) a	(n=257) b	(n=160) c	(n=64) d	(n=47) e	(n=285) f	(n=21) g
Under $60	**14%**	13%	17%	20% g	11%	14% g	5%
$60 to $89	**16%**	18% c	12%	13%	17%	16%	19%
$90 to $149	**18%**	18%	18%	19%	28% g	17%	10%
$150 or more	**36%**	37%	34%	34%	34%	36%	43%
Not sure	**16%**	14%	19%	14%	11%	17%	24%
Mean	$159.1	$158.3	$160.6	$131.9	$160.3	$162.8 d	$194.7
Median	$115.0	$120.0	$110.0	$104.0	$107.5	$120.0	$155.0
Tier Reached in Summer							
Tier 1	**10%**	9%	11%	8%	13%	9%	14%
Tier 2	**18%**	20% c	14%	16%	26% g	17%	10%
Tier 3	**16%**	14%	18%	17%	17%	15%	14%
Tier 4	**9%**	9%	8%	9%	4%	9%	10%
Not sure	**48%**	47%	49%	50%	40%	48%	52%

Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Q6.3: "Now, think about your electric bills last year. What was your average monthly electric bill during the last summer, May through October? Please exclude the natural gas part."
Q6.4: "What electric usage tier does your household typically reach during the summer months?"

Average Winter Electric Bill

➢ Average winter electric bill amounts are somewhat lower than summer, with a median of $100 and a mean of $144.

- The highly interested have winter bills that are closer to their summer bill amounts than do the moderately interested, so this could be a factor that influences interest in solar. Those who prefer the Demand Charge rate plan have the lowest average winter bills (as well as summer).

		Level of Interest		Rate Plan Preference			
Average Monthly Winter Electric Bill	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c	Demand Charge (n=64) d	Installed Capacity Charge (n=47) e	Feed-in Tariff/VOS (n=285) f	Panel Rate (n=21) g
Under $60	17%	16%	19%	22% g	13%	18% g	5%
$60 to $89	19%	19%	18%	23% g	32% fg	16%	10%
$90 to $149	18%	18%	17%	20%	17%	17%	24%
$150 or more	29%	30%	26%	20%	26%	31% d	33%
Not sure	18%	16%	21%	14%	13%	19%	29%
Mean	$143.7	$153.3	$127.4	$106.9	$160.3	$148.7 d	$155.0
Median	$100.0	$100.0	$90.0	$80.0	$85.0	$100.0	$100.0
Tier Reached in Winter							
Tier 1	13%	12%	14%	13%	17%	13%	14%
Tier 2	20%	21%	19%	14%	34% df	19%	24%
Tier 3	10%	10%	11%	14% e	4%	11% e	10%
Tier 4	7%	9% c	4%	6%	2%	8% e	10%
Not sure	49%	47%	53%	53%	43%	50%	43%

Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Q6.5: "What was your average monthly electric bill during the last winter, November through April? Please exclude the natural gas part."
Q6.6: "What electric usage tier does your household typically reach during the winter months?"

Type, size, age, and market value of home

SDG&E service received, rate and payment plans enrolled in

Contact with SDG&E in past 12 months

Household Characteristics

Homeowners Interested in Solar

Type of Home & SDG&E Service

- Nearly all (90%) solar interested homeowners live in a single family detached home, while another 10% are in attached homes.
  - All other home types were excluded from the survey, including multi-family condominiums and mobile homes.
  - Although it is possible for those in attached homes to add solar, additional barriers prevent this to a large degree (such as HOA rules, difficulties getting agreement from neighbors, etc.). Despite this, the highly interested group includes more who live in attached homes.
  - Panel Rate preferring customers are more likely all electric, single family attached homes.

		Level of Interest		Rate Plan Preference			
Type of Home	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
Single family detached	**90%**	88%	94% b	89%	98% dfg	90%	76%
Single family attached	**10%**	12% c	6%	11% e	2%	10% e	24% e
Services Received from SDG&E							
Electric & Gas	**87%**	88%	86%	91% g	85%	88% g	67%
Electric Only	**13%**	12%	14%	9%	15%	12%	33% df

QS4: "Which of the following best describes the type of home you live in?"
QS2: "Which of the following services do you receive from SDG&E?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Size and Age of Home

➢ The distribution of interested homeowners ranges across home sizes.

- The highly interested are in somewhat smaller homes compared to the moderates.
- Those who prefer the Demand Charge rate plan are more likely in smaller, older homes.

		Level of Interest		Rate Plan Preference			
Size of Home (sq. ft.)	**Interested Homeowners**	**Highly Interested**	**Moderately Interested**	**Demand Charge**	**Installed Capacity Charge**	**Feed-in Tariff/VOS**	**Panel Rate**
	(n=417) a	(n=257) b	(n=160) c	(n=64) d	(n=47) e	(n=285) f	(n=21) g
Under 1,500	**23%**	25%	20%	31% e	17%	22%	29%
1,500 to 1,999	**31%**	32%	29%	28%	36%	31%	33%
2,000 to 2,499	**19%**	18%	21%	16%	17%	20%	19%
2,500 or more	**27%**	25%	30%	25%	30%	28%	19%
Year Home Built							
Before 1970	**24%**	24%	24%	28% g	23%	24% g	10%
1970 to 1979	**18%**	19%	18%	23%	13%	18%	29%
1980 to 1989	**24%**	24%	23%	25%	21%	24%	24%
1990 to 1999	**17%**	14%	21% b	16%	17%	18%	10%
2000 to 2009	**12%**	13%	10%	5%	17% d	12% d	19%
2010 or newer	**2%**	2%	2%	2%	-	2% eg	-
Not sure	**4%**	4%	3%	2%	9%	3%	10%
Mean	**1979**	**1979**	**1979**	**1976**	**1980**	**1980**	**1984 d**

QH1: "About how many square feet is your home?"
QH2: Approximately in what year was your home built? Record the nearest decade if not known exactly."
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Current Market Value of Home

- Interested homeowners' market values range widely from under $350,000 to well over $850,000. The mid-point is in the $500,00-$649,000 range.
  - Those highly interested in solar are more likely to be in *less* expensive homes compared to the moderately interested. There are some demographic reasons for this – mainly that the highly interested are younger and with somewhat lower incomes than the moderately interested.

Market Value of Home	Interested Homeowners (n=417) a	Level of Interest: Highly Interested (n=257) b	Level of Interest: Moderately Interested (n=160) c	Rate Plan Preference: Demand Charge (n=64) d	Rate Plan Preference: Installed Capacity Charge (n=47) e	Rate Plan Preference: Feed-in Tariff/VOS (n=285) f	Rate Plan Preference: Panel Rate (n=21) g
Under $350,000	11%	14% c	5%	14%	6%	10%	19%
$350,000 to $499,000	27%	27%	27%	25%	34%	26%	24%
$500,000 to $649,000	22%	23%	21%	17%	23%	24%	14%
$650,000 to $849,000	18%	17%	19%	19%	15%	18%	19%
$850,000 or more	18%	14%	23% b	22%	15%	17%	24%
Not sure	4%	3%	5%	3%	4%	4% g	-

QH4: "What is your best guess of your home's current market value?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Current Rate and Payment Plans

➢ Relatively few interested homeowners are on CARE or medical baseline. One in three (33%) are enrolled in online billing and just as many (35%) have My Account.

- Differences between the highly and moderately interested are relatively minor.
- Those who prefer the Installed Capacity Charge are more likely on a Level Pay Plan, but less likely to have My Account online access.

		Level of Interest		Rate Plan Preference			
Rate Plans	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
Solar or Net Energy Metering (NEM)	< 1%	< 1%	-	-	-	<1%	-
CARE or FERA (discount for low income)	6%	7%	6%	5%	4%	7%	5%
Medical Baseline	6%	6%	4%	2%	9%	6% d	5%
Time-of-Use (TOU) Rate Plan	1%	2%	1%	-	2%	2% dg	-
Electric Vehicle (EV or EPEV) Rate Plan	1%	1%	1%	2%	2%	1%	-
Payment Plans							
Online Billing	33%	34%	31%	33%	26%	35%	24%
Automatic Payment Service	18%	18%	18%	17%	13%	19%	10%
Level Pay Plan	6%	5%	6%	3%	11% g	6% g	-
My Account (online access)	35%	33%	38%	34%	23%	36% e	43%
None of these	34%	33%	34%	36%	40%	33%	24%
Not sure	6%	5%	7%	6%	6%	5%	19%

QH5: "Are you currently enrolled on any of these special electric rate plans or payment programs?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Contact with SDG&E Past 12 Months

➢ About one in four interested homeowners (29%) said they had contact with SDG&E in the past 12 months.

- Most contact has been by telephone followed by service visits to their home.
- The moderately interested are more likely to have had a service visit at their home and less likely to have gone to a branch office.

		Level of Interest		Rate Plan Preference			
Contact with SDG&E	Interested Homeowners (n=417) a	Highly Interested (n=257) b	Moderately Interested (n=160) c	Demand Charge (n=64) d	Installed Capacity Charge (n=47) e	Feed-in Tariff/VOS (n=285) f	Panel Rate (n=21) g
No contact	68%	**67%**	**69%**	**72%**	**66%**	**68%**	**62%**
Had contact	**29%**	**30%**	**29%**	**25%**	**34%**	**29%**	**33%**
Telephone	25%	26%	23%	**20%**	21%	26%	29%
Service visit at home	6%	4%	9% b	6%	9%	5%	10%
Branch office	1%	2% c	-	-	-	2% dfg	-
In-person at event, presentation, or exhibit	1%	1%	2%	-	2%	1% dg	-
Other	1%	1%	1%	2%	4%	-	-
Not sure	**3%**	**3%**	**3%**	**3%**	-	**3% e**	**5%**

QH6: "Have you had contact with your local utility in the past 12 months, either by phone or in-person? This might be a call to a customer service representative, a service visit in your home, a community event, a presentation, or an exhibit?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Number of people in household, age, annual household income, gender employment status, ethnicity, and language spoken in the home

Demographic Characteristics

Homeowners Interested in Solar

Age and Nr. Living in Home

- Interested homeowners have a high concentration in the 56 to 65 year age range, probably because of the homeownership requirement and affordability regarding solar.
  - Those who are highly interested, though, are more likely to be younger. Likewise, they are also more likely to be in single person households or in larger (3+) households.
  - Those who prefer the Feed-In-Tariff/VOS are older than those who prefer one of the other three rate plan options.

		Level of Interest		Rate Plan Preference			
Age	**Interested Homeowners**	**Highly Interested**	**Moderately Interested**	**Demand Charge**	**Installed Capacity Charge**	**Feed-in Tariff/VOS**	**Panel Rate**
	(n=417) a	(n=257) b	(n=160) c	(n=64) d	(n=47) e	(n=285) f	(n=21) g
Under 35	**17%**	20% c	13%	23%	19%	15%	24%
36 to 45	**15%**	16%	12%	16%	26% fg	13%	10%
46 to 55	**22%**	21%	24%	22%	30%	21%	14%
56 to 65	**33%**	31%	36%	27%	19%	36% e	29%
66 to 75	**10%**	10%	11%	9%	6%	11%	19%
76 or older	**2%**	2%	3%	3%	-	2% e	5%
Prefer not to answer	**1%**	<1%	3%	-	-	2% deg	-
No. Living in Home							
1	**10%**	11%	9%	8%	13%	10%	10%
2	**43%**	39%	48% b	39%	36%	45%	38%
3	**19%**	20%	17%	22% g	19% g	19% g	5%
4 or more	**29%**	30%	26%	31%	32%	26%	48% f
Mean	2.8	2.9	2.8	3.0	2.9	2.8	3.2

QD2: "What is your age?"
QD1: "Including you, how many people live in your household?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Income and Gender

- Income distributions of interested homeowners show the median in the $75,000 - <$100,000 range.
  - Interestingly, the moderately interested are more likely to have higher incomes ($150k or more) than the highly interested.
  - Also, the interested homeowners include more females than males, which is typical of surveys among household bill payers.
  - Household income is slightly lower for those who prefer the Installed Capacity Charge.

		Level of Interest		Rate Plan Preference			
Annual Household Income	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
Under $53,000	14%	15%	14%	14%	11%	15%	14%
$53,000 to < $75,000	12%	14%	11%	13%	11%	13%	14%
$75,000 to < $100,000	22%	22%	21%	20%	30%	20%	24%
$100,000 to < $150,000	21%	23%	17%	27% g	26% g	19%	10%
$150,000 or more	23%	20%	28% b	22%	15%	25% e	24%
Prefer not to answer	8%	7%	9%	5%	9%	8%	14%
Gender							
Female	61%	62%	59%	67%	62%	60%	57%
Male	39%	38%	41%	33%	38%	40%	43%

QD3: "What is your annual household income before taxes?"
QD4: "Are you male or female?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Education and Employment

➢ Interested homeowners are primarily college graduates, with 30% having a master's or doctorate degree.

- Most interested homeowners are employed (full or part-time) or retired. The moderately interested have a higher proportion of retired persons than the highly interested, consistent with their higher average age. Those who prefer the Installed Capacity Charge are more likely full time employed.

		Level of Interest		Rate Plan Preference			
Education	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
High School or Trade School	20%	24% c	15%	27%	19%	19%	19%
College Degree	49%	47%	52%	44%	47%	51%	52%
Masters or Doctorate	30%	28%	33%	28%	32%	30%	29%
Prefer not to answer	1%	1%	1%	2%	2%	1%	-
Employment Status							
Employed: Full Time	54%	54%	55%	45%	72% dfg	54%	43%
Employed: Part Time	14%	16%	11%	16%	9%	14%	24%
Unemployed or Between Jobs	2%	2%	2%	-	-	3% deg	-
Homemaker or Caregiver	7%	7%	7%	11% e	-	6% e	19% e
Student	2%	2%	1%	3%	4%	1% g	-
Retired	20%	18%	24% b	23%	15%	21%	14%
Prefer not to answer	1%	2%	1%	2%	-	1% eg	-

QD5: "What is the last year of school you completed?"
QD6: "What is your current employment status?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Ethnicity and Languages Spoken

- About three out of four interested homeowners identified their ethnicity to be white (non-Hispanic), with the reminder being primarily Asian or Hispanic.
  - Nearly all respondents said they speak English at home – as expected since the survey was completed in English. The highly interested are more likely to speak Spanish than the moderately interested.

		Level of Interest		Rate Plan Preference			
Ethnicity	**Interested Homeowners** (n=417) a	**Highly Interested** (n=257) b	**Moderately Interested** (n=160) c	**Demand Charge** (n=64) d	**Installed Capacity Charge** (n=47) e	**Feed-in Tariff/VOS** (n=285) f	**Panel Rate** (n=21) g
White (not Hispanic)	73%	75%	69%	77% e	60%	75% e	62%
Asian or Pacific Islander	10%	9%	12%	13%	17%	8%	14%
Hispanic or Latin American	9%	9%	8%	5%	13%	9%	10%
African-American	2%	2%	2%	2%	4%	2% g	-
Native American	< 1%	-	1%	-	-	<1%	-
Mixed	3%	3%	3%	2%	2%	4%	5%
Other	< 1%	<1%	1%	2%	-	-	5%
Prefer not to answer	3%	1%	5% b	2%	4%	2%	5%
Languages Spoken in Home							
English	96%	95%	97%	95%	98%	96%	95%
Spanish	9%	11% c	6%	6%	11%	9%	5%
Asian (Chinese, etc.)	6%	5%	6%	9%	9%	4%	5%
Other	2%	2%	2%	2%	2%	1%	10%
Prefer not to answer	1%	1%	1%	2%	-	1%	5%

QD7: "What do you consider your ethnicity to be?"
QD8: "What languages do you speak in your home?"
Letters indicate a significant difference at the 90% confidence level for the following groups: b/c; d/e/f/g

Docket Nos. 15-07041/42

Exhibit RTB-3

Sierra Pacific Power Company / Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.: 15-07041/15-07042 **REQUEST DATE:** 9/30/2015

REQUEST NO.: TASC 86

REQUESTER: **RESPONDER:** Faruqui, Ahmad

REQUEST:

Please refer to the Direct testimony of Ahmad Faruqui, page 15: "Marginal cost of service studies establish a measure of long-run marginal costs for various aspects of utility costs. If these costs are then passed on to customers with minimal distortions (distortions are needed for revenue recovery), then customers will pay cost-reflective prices that enable them to make optimal decisions. A cost-benefit study does not estimate marginal costs or prices of any kind. Rather, it focuses on whether a specific investment, policy or program is desirable or not. For these reasons, cost-benefit studies are not suitable for determining rates."

a) What conclusions does Dr. Faruqui draw from the E3 study with regard to whether NEM is desirable or not?

b) In general, should the results of cost-benefit studies be used to inform rate design in any way? If so, how? If not, why not?

c) How should the results of the E3 study be used to inform rate design in this docket?

d) Has Dr. Faruqui conducted or reviewed any analyses of how residential customers are likely to respond to the price signals from the NVE's three-part rate proposal? If so, please provide the analysis and describe how it influenced your recommendations? If not, why not?

RESPONSE CONFIDENTIAL: No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a) Dr. Faruqui's testimony regarding marginal cost of service, in particular the excerpt provided in the question, is not informed by the E3 study, which is not based on marginal cost of service.

b) No, it should not, as explained in the answer to question 28 of Dr. Faruqui's direct testimony.

c) The results of the E3 study should not be used to inform rate design as it is a cost-benefit study.

d) A review of NV Energy's proposed three part rate proposals indicates that it would be applicable only to a new class of customers, NEM2 customers. The three part rate is not intended to apply to residential customers. Dr. Faruqui has not conducted or reviewed an analysis of how residential customers are likely to respond to the price signals from the NV Energy utilities' three-part rate proposal for NEM 2 customers.

Docket Nos. 15-07041/42

Exhibit RTB-4

Sierra Pacific Power Company / Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.:	15-07041/15-07042	**REQUEST DATE:**	10/5/2015
REQUEST NO.:	TASC 107		
REQUESTER:		**RESPONDER:**	Walsh, Laura

REQUEST:

Request:

Please provide a list of benefits that NPC or SPPC has identified that NEM customers provide to non-NEM customers. For each of the identified benefits, please provide the economic value associated with each benefit.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

In preparing these filings, NVE did not attempted to perform an analysis to identify "benefits" provided by and to non-NEM and NEM customers. Marginal cost of service is developed by class and is used to develop class revenue requirement and cost based rates for the electric service the utility provides to its customers. Each class "benefits" when the costs assigned to each class reflect marginal cost of service.

Please see Section 3 and the Technical appendix of each filing for the marginal cost analysis performed.

Docket Nos. 15-07041/42

Exhibit RTB-5

Sierra Pacific Power Company / Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.: 15-07041/15-07042 **REQUEST DATE:** 9/18/2015

REQUEST NO.: TASC 09

REQUESTER: **RESPONDER:** Murray, Jesse

REQUEST:

Request:

Please provide:

a. NPC's most recent accounting for how it plans to comply with Nevada's Renewable Portfolio Standard (RPS) requirements, including banking, PECs, energy efficiency, and the expected role that DG PV will play in meeting those requirements. Please include forecasted costs for RPS compliance.
b. NPC's purchases, sales, and retirements of Renewable Energy Credits (RECs) or Portfolio Energy Credits (PECs), in MWh and total dollars, in each of the last five years (2010-2014). Please show whether these transactions count toward Nevada's RPS or toward some other state's RPS.
c. NPC's most recent plan for compliance with the federal Environmental Protection Agency's Clean Power Plan.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENTS CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: Two (zipped)

RESPONSE:

A. Attached is an excel file containing the NPC's last compliance outlook and cost information. The outlook is based on NPC's June IRP preferred renewable expansion plan with two adjustments. The attached outlook has been adjusted to exclude credits from Switch Station and credits from subscription solar (credits from Switch Station will be assigned to Switch and credits from subscription solar will be assigned to the subscribers). The annual costs associated with acquiring the various renewable energy credits are shown on lines 131–134 of the NPC Expansion Plan worksheet. These costs shown are estimates and do not include utility administration. The estimated purchase power and credit only costs shown on line 131 are based on the PPA terms and assume no under or over deliveries. The majority of these purchases are for bundled product, so the cost shown on line 131 includes energy; there is no practical way of splitting this cost into energy and credit components. Because credits acquired from approved efficiency and renewable generation programs span several years and excess credits can be banked for future use, there is no one-to-one relationship between the cost to acquire credits in a given year, and the cost to retire credits in the same year.

B. Attached is an excel filing containing NPC's historic RPS compliance. This file is based on annual compliance filings for 2010 to 2014. The annual costs shown on lines 125–127 of the NPC worksheet exclude utility administration. The majority of energy and credit purchases shown on line 125 are for bundled product, so the cost will include the cost of the energy; there is no practical way of splitting the cost into energy and credit components. There is not a one-to-one relationship between the costs to acquire credits in a given year and the actual credits retired. Credits acquired from approved efficiency and renewable generation programs can span several years and excess credits can be banked for future use. The utility does not assign costs to credit certificates. Credits are retired using a first in, first out methodology subject to all statutory requirements and limitations.

C. NPC has not yet developed a resource plan to comply with EPA's Clean Power Plan. The state target has not yet been finalized, and the CPP has also not yet been published in the Federal Register and could therefore change. This rule could also be subject to litigation which cannot be filed until the final rule appears in the Federal Register. The Company expects to work closely with the State, including the Public Utilities Commission and Bureau of Consumer Protection, to develop a resource strategy that will allow it to meet the CPP targets once the state target and rules are completed.

Docket Nos. 15-07041/42

Exhibit RTB-6

Sierra Pacific Power Company / Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.: 15-07041/15-07042 **REQUEST DATE:** 9/18/2015

REQUEST NO.: TASC 22

REQUESTER: **RESPONDER:** Walsh, Laura

REQUEST:

Request:

Please provide the rate impacts and bill savings for non-NEM residential and general service customers of NPC that will become effective on January 1, 2016, if NPC's proposal in these dockets is approved effective on January 1, 2016. If the rate impacts and bill savings for non-NEM residential and general service customers of NPC resulting from NPC's proposal will not become effective on January 1, 2016, when will they become effective, and what will those rate impacts and bill savings be at that time?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

If approved as proposed by NV Energy, the proposed rates will only impact NEM2 customers. NEM1 and non-NEM customers in the residential and small general service customer classes will not be impacted as a result of this docket. Please see the response to SNHBA 2-21.

Docket Nos. 15-07041/42

Exhibit RTB-7

Sierra Pacific Power Company / Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.: 15-07041/15-07042 **REQUEST DATE:** 9/18/2015

REQUEST NO.: TASC 66

REQUESTER: **RESPONDER:** Franklin, Pat

REQUEST:

Request:

For years 2010, 2011, 2012, 2013, 2014 and for 2015 through August 30, 2015, please provide the amount of over earnings separately for Nevada Power and Sierra Pacific Power.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

For Nevada Power's retail jurisdiction, rates effective in 2010 and 2011 were established in Docket No. 08-12002 based on a test year ending June 30, 2008 and a November 30, 2008 certification. These rates reflect an authorized regulatory rate of return of 8.66% on a rate base of $4.69 billion. For the calendar year 2010, Nevada Power's retail jurisdiction earned a regulatory rate of return 7.22% on an end of year rate base of $4.97 billion. For the calendar year 2011, Nevada Power's retail jurisdiction earned a regulatory rate of return of 6.40% on an end of year rate base of $5.38 billion.

Rates effective in 2012, 2013 and 2014 were established in Docket No. 11-06006 based on a calendar 2010 test year and a May 31, 2011 certification. These rates reflected a regulatory rate of return with incentives of 8.17% on a rate base of $5.48 billion. For calendar year 2012, Nevada Power's retail jurisdiction earned a regulatory rate of return of 8.58% on an end of year rate base of $5.18 billion. Statement F, filed in Docket 13-03003, reported an earned rate of return of 8.71% for 2012. However, the 8.71% earned rate of return reflected energy efficiency implementation rate revenue and the Commission subsequently determined that such revenue would be refunded to customers. For the calendar year 2013, Nevada Power's retail jurisdiction earned a regulatory rate of return 8.49% on an end of year rate base of $5.16 billion. For the calendar year 2014, Nevada Power's retail jurisdiction earned a regulatory rate of return 9.17% on an end of year rate base of $4.90 billion. However, pursuant to the stipulation in Docket No. 13-07021, the Company distributed a one-time billing credit to customers in the amount of $15 million. This credit is not reflected in the earned rate of return.

For Sierra's retail electric jurisdiction, rates effective in 2010 were established in Docket No. 07-12001 based on a historical test year ending June 30, 2007 and an estimated test year service ending June 30, 2008 pursuant to NRS 704.110,4. These rates reflected a regulatory rate of return with incentives of 8.60% on a rate base of $1.57 billion. For the calendar year 2010, Sierra's retail electric jurisdiction earned a regulatory rate of return of 7.10% on an end of year rate base of $1.52 billion.

Rates effective in 2011, 2012 and 2013 were established in Docket No.10-06001 based on a calendar 2009 test year and a May 31, 2010 certification. These rates reflected a regulatory rate of return with incentives of 8.06% on a rate base of $1.58 billion. For the calendar year 2011, Sierra's retail electric jurisdiction earned a regulatory rate of return of 7.94% on an end of year rate base of $1.52 billion. For the calendar year 2012, Sierra's retail electric jurisdiction earned a regulatory rate of return of 8.31% on an end of year rate base of $1.53 billion. Sierra's electric retail earned rate of return was reported as 8.50% in Statement F in Docket 13-03004. Again, the 8.50% earned of return reflected energy efficiency implementation rate revenue and the Commission subsequently determined that such revenue would be refunded to customers. For the calendar year 2013, Sierra's retail electric jurisdiction earned a regulatory rate of return of 9.02% on an end of year rate base of $1.52 billion.

Rates effective in 2014 were established in Docket No.13-06002 based on a calendar 2012 test year and a May 31, 2013 certification. These rates reflected a regulatory rate of return with incentives of 7.78% on a rate base of $1.49 billion. .For the calendar year 2014, Sierra's retail electric jurisdiction earned a regulatory rate of return 8.74% on an end of year rate base of $1.47 billion. Pursuant to the stipulation in Docket No. 13-07021, the Company distributed a one-time billing credit to customers in the amount of $4.6 million. This credit is not reflected in the earned rate of return.

For Sierra's Gas Department, rates effective in 2010, were established in Docket No. 05-10002 a test year ending May 31, 2005 and an October 31, 2005 certification. . These rates reflected a regulatory rate of return of 7.98% on a rate base of $149.6 million. For the calendar year 2010, Sierra's Gas Department earned a regulatory rate of return 3.82% on an end of year rate base of $188.9 million.

Rates effective in 2011, 2012 and 2013 were established in Docket No. 10-0005 based on a calendar 2009 test year and a May 31, 2010 certification. . These rates reflected a regulatory rate of return with incentives of 5.18% on a rate base of $185.6 million. For the calendar year 2011, Sierra's Gas Department earned a regulatory rate of return 4.48% on an end of year rate base of 174.1 million. For the calendar year 2012, Sierra's Gas Department earned a regulatory rate of return 2.50% on an end of year rate base of $206.7 million. For the calendar year 2013, Sierra's Gas Department earned a regulatory rate of return 2.89% on an end of year rate base of $217.5 million.

Rates effective in 2014 were established in Docket No. 13-06003 based on a calendar 2012 year and a May 31, 2013 certification. These rates reflected a regulatory rate of return with incentives of 6.04% on a rate base of $191.6 million. For the calendar year 2014, Sierra's Gas Department earned a regulatory rate of return 4.86% on an end of year rate base of $197.8 million. Pursuant to the stipulation in Docket No. 13-07021, the Company distributed a one-time billing credit to customers in the amount of $0.4 million. This credit is not reflected in the earned rate of return.

Note:
The earned rates of return for 2015 will not be known until after the books are closed at December 31, 2015. The Companies do not calculate earned return on a partial year. As mentioned above, the earned rates of return have been calculated on an end of test year rate base pursuant to NAC 704.150. Common financial metrics focus on average equity or average rate base, not year-end equity or year-end rate base. In fact, NAC 704.9524.2(b)(2) as revise in Docket No.14-10008 (effective September 1, 2015) requires the use of average rate base in the rate of return calculations relative to energy efficiency implementation recovery.