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Transcript Exhibit(s)

Docket #(s): E-000005-14-0023

Arizona Corporation Commission
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Exhibit #: TASC 20-30, TEP 1-4

Part 5 of 5

For parts 1-4, see barcodes 0000171007, 0000171008, 0000171009 + 0000171040

Impact of High PV Penetration on Distribution Transformer Insulation Life

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***Abstract*—The reliable operation of distribution systems is critically dependent on detailed understanding of load impacts on distribution transformer insulation systems. This paper estimates the impact of rooftop photovoltaic (PV) generation on a typical 200-kVA, 22/0.415-kV distribution transformer life under different operating conditions. This transformer supplies a suburban area with a high penetration of roof top photovoltaic systems. The transformer loads and the phase distribution of the PV systems are significantly unbalanced. Oil and hot-spot temperature and remnant life of distribution transformer under different PV and balance scenarios are calculated. It is shown that PV can significantly extend the transformer life.**

***Index Terms*—Distribution transformer, life assessment, roof top PV, unbalanced operation.**

I. Introduction

MODERN distribution systems serve a variety of diverse customers. Three-phase four-wire systems, such as 400/230-Vrms systems found in Europe, the U.K., and Australia, will typically serve 60 to 120 consumers with a single transformer. The customers may be three or single phase. Some efforts are made at construction to balance the phase loading but significant unbalances develop during normal operation. While the systems are robust, unbalance has undesirable effects including reduced transformer life, increased losses and power quality problems due to phase voltage variations and negative sequence voltages.

Transformers operated under unbalanced conditions will suffer more extreme stresses than under balanced conditions. The transformer life is largely determined by the insulation life [1]–[3]. Mechanical, electrical, and thermal stresses affect the oil-paper insulation system [4]. The main factors that determine the insulation life of oil-immersed transformers are the transformer load, ambient temperature, moisture content and the oxygen content of the oil [5]. For unbalanced loading the resulting increased loss, and the concentration of the losses in one or two phases, affects the insulation system of the transformer and reduces its life time [6], [7].

To maximize the return on their investment, utilities will take advantage of a transformer's full cyclic loading capability to achieve to financial savings and reduced operating costs. Optimal utilization of a transformer can be achieved by taking advantage of a transformer's thermal time constant and the diurnal variation of the load and ambient temperature. It is necessary to have accurate models for predicting winding hot-spot temperature (HST) and top-oil temperature (TOT).

The development of accurate prediction models of the HST and TOT for substation, distribution and power transformers has been the subject of a substantial amount of research [15]–[17]. IEEE Standard C57.91-1995 [8] and IEC standard 60076-7 [9] describe in detail methods to calculate the HST and offer guidance on temperatures that should not be exceeded at either winding or structural hotspots to avoid undue aging failures from gassing. These standards, and recent publications, assume balanced loading of the transformer. Residential transformers have a high degree of unbalance. It is practically difficult to maintain an accurate knowledge of the street phase connections due to network maintenance and recording errors.

PV at the distribution level has become widespread. Previous studies [24]–[26] have identified many impacts that roof top PV may have on a local distribution network including changes in voltage profile and network power flows [24]. The problem of voltage fluctuations resulting from the passage of clouds is also addressed in [27], [28]. In particular, variations of nodal voltages in small or weak electrical grids (e.g., SWER systems) have been reported to cause system instability. Studies have also been conducted to explore the extent to which the geographical diversity of distributed PV mitigates the short term output variability caused by rapidly changing weather conditions. Spatial distribution significantly reduces transients caused by clouds.

Distribution systems are typically designed for specific load profile based on consumption patterns. When roof top PVs are deployed, the pattern of electric power demand will change. Australian residential consumption has an early evening peak. The addition of PV does not strongly reduce the peak load but will reduce the energy served. As a result the load factor, the ratio of average to peak load, is reduced. This paper studies the impact of roof top PV on the transformer insulation life. A dynamic thermal model was used for the prediction of the hot-spot temperature. The insulation aging impact was analysed using one year of residential electric power load data, drawn from the Perth Solar City High Penetration PV Trial, [10]. One year of ambient temperature data is integrated into the model to estimate the life impact.

Manuscript received February 13, 2013; revised May 21, 2013 and August 20, 2013; accepted October 16, 2013. This work was supported by the National and International Research Alliances Program of the Queensland Government. Paper no. TPWRD-00146-2013.

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Digital Object Identifier 10.1109/TPWRD.2013.2287002

The work can be separated into two main steps. The first step is to identify the consumer phase connection and to process smart meter data to allow two data sets to be established. These data sets are the actual transformer phase loading and the loading that would have resulted in the absence of the installed PV systems. The second step is to use these two data sets to calculate the transformer hot-spot and oil temperatures under the different scenarios. The addition of PV is shown to be beneficial with regard to hot-spot temperatures and reduces the transformer loss of life (LOL).

II. Data Acquisition and Phase Allocation

The 400/230 V feeder, shown in Fig. 1, is supplied from a 200 kVA Dyn 22 kV/400 V distribution transformer and includes 77 residential consumers. Of these, 34 consumers have roof top PV systems which have average ratings of 1.88 kW. The total installed PV capacity is 64 kW representing a penetration of 32%. Load data, including energy consumption solar power generation, voltage and current is recorded by smart meters on the Western Power network at the point of connection to each consumer switchboard at 15-min intervals. Smart meter data has been collected since July 2011. At the time of the recording there were two three phase meters (meter number 49 and 55) that were not active and no recording available for these meters.

To determine the loading of the transformer the authors have previously published a method using cross correlation of consumer voltage profiles to identify their phase connection [11]. Using the known phase connections of the residential loads, the data collected from the smart meters was aggregated to determine the phase loading on the transformer. Fig. 2 shows the predicted transformer loading (kW) during the 7-day window that includes the annual peak day. The sampling rate is 15 minutes. The network under study is significantly unbalanced but reflective of normal network conditions. The unbalance results from the poor allocation of customer loading among the three phases. For instance, the loading of phase A is much less than phase B and C during day time peak hours.

III. Thermal Aging Formulation

A. Loss of Life of Distribution Transformer

Several models have been introduced to assess life estimation of insulation in transformers [1]–[4], [12], [13]. A wide variety of methods has been presented for loss-of-life inference for power and distribution transformers, such as those proposed in [14], Clause 7 and updated in [15]. When inferring the transformer LOL acceleration rate using these methods, the calculation of the winding hot-spot temperature (HST) is the most critical issue [3], [4]. The methods proposed in [1], [2] were followed by a series of papers [5]–[7], [12], [13], [15] dealing with more accurate calculations of HST.

Although deterioration of insulation is a function of temperature, moisture content, oxygen content and acid content, the model presented in this paper is based only on the insulation temperature [9]. Since the temperature distribution is not uniform, the part that is operating at the highest temperature will normally undergo the greatest deterioration. Therefore, the rate

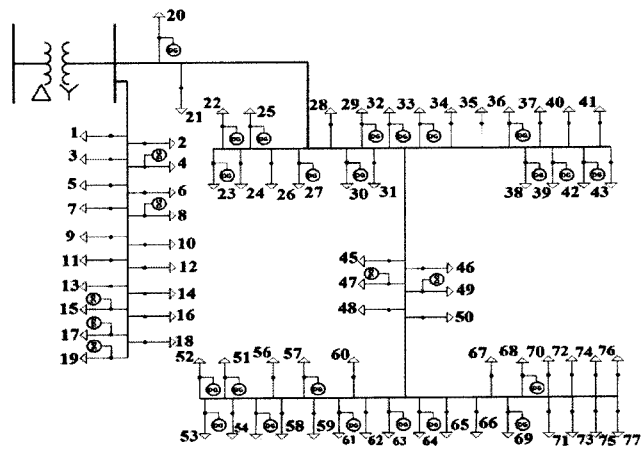

Fig. 1. Perth Solar City High Penetration Feeder Site, image courtesy of Western Power.

of aging is referred to the winding hot-spot temperature. Equations (1) and (2) describe, respectively, the relative aging rate VT for a thermally upgraded paper (reference temperature of 110°C) and non-thermally upgraded paper (reference temperature of 98 °C) [9]

$$V_T = 2^{\theta_h - 98/6} \tag{1}$$

$$V_T = e^{\left[\frac{15000}{110+273} - \frac{15000}{\theta_h + 273}\right]}. \tag{2}$$

Temperature is of importance since chemical reactions such as the deterioration of cellulose in paper is accelerated at elevated temperatures. In Table II, the thermal model parameters are presented. The equivalent life at the reference temperature that will be consumed in a given time period for an actual temperature cycle can be calculated by (3) [8], where V_{EQA} is equivalent aging factor for the total time period, n is index for the time interval t, N is total number of time intervals, Δt_n is the time interval and V_n is aging acceleration factor for the time interval Δt_n

$$V_{EQA} = \frac{\sum_1^N V_n \Delta t_n}{\sum_1^N \Delta t_n}. \tag{3}$$

When a normal insulation life for a well-dried oxygen-free transformer system is defined, percent loss of insulation life can be calculated in (4) [8]. In this paper, we choose the normal life as 180,000 hours (20.55 years). Under this normal life value, normal percent loss of life for operation at a rated hot-spot temperature of 110°C for 24 h is 0.0133%

$$\%\ \text{Loss of Life} = \frac{V_{EQA} \times t \times 100}{\text{Normal insulation life}}. \tag{4}$$

The normal life expectancy is a conventional reference basis for continuous duty under normal ambient temperature. and rated operating conditions.

B. Hot-Spot Temperature Model

In [14], a transformer thermal model was developed as a series of algebraic difference equations. In [16], [17], Swift *et al.*

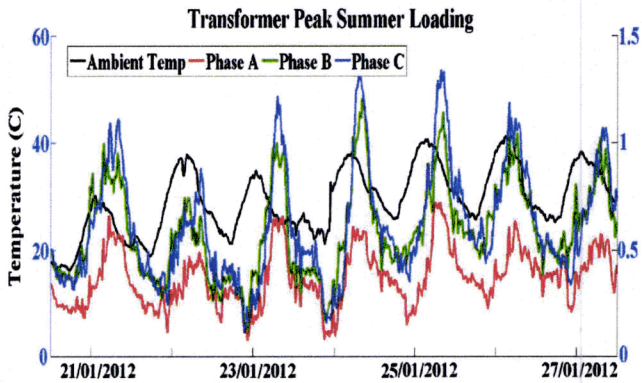

Fig. 2. Pavetta transformer power output, January 21–27, 2012.

TABLE I
TOP OIL AND HST COMPARISON UNDER DIFFERENT LOADING CONDITION

	HST (°C)			Top Oil (°C)
	Phase A	Phase B	Phase C	
Solar-1.0 pu	94.4	117.3	128.9	76.1
No solar-1.0 pu	97.6	120.3	133.6	78.7
Solar-1.1 pu	99.3	124.4	137.9	79.5
No solar-1.1 pu	102.1	127.7	142.3	82.1
Solar-1.2 pu	107.7	136.5	151.7	85.0
No solar-1.2 pu	111.0	140.3	157.2	88.0
Solar-1.3 pu	116.7	149.3	166.8	90.9
No solar-1.3 pu	120.3	153.7	172.8	94.3
Solar-1.4 pu	126.0	162.7	180.7	95.1
No solar-1.4 pu	130.2	167.6	189.2	100.9

proposed a basic approach based on heat transfer based on the application of the lumped capacitance, thermal resistance electrical analogy. The transformer heating model used in this analysis is based on [9] (Fig. 2) IEC 60076 develops the hotspot temperature equations in the following way:

$$\theta_{h_{(n)}} = \theta_{o_{(n)}} + \Delta\theta_{h_{(n)}} \tag{5}$$

where θ_h is the HST in degrees Celsius, θ_o is the top-oil temperature at the current load, and $\Delta\theta_h$ is the total HST rise at the nth time step, where Δ is calculated in (6)

$$\Delta\theta_{h_{(n)}} = \Delta\theta_{h1_{(n)}} + \Delta\theta_{h2_{(n)}}. \tag{6}$$

$\Delta\theta_{h1(n)}$ and $\Delta\theta_{h2(n)}$ are derived from the difference equations for HST rise, and can be calculated

$$\Delta\theta_{h1_{(n)}} = \Delta\theta_{h1_{(n-1)}} + \frac{Dt}{k_{22}\tau_w} \times \left[k_{21} \times \Delta\theta_{hr} Ka^y - \Delta\theta_{h1_{(n-1)}}\right] \tag{7}$$

where Dt is the time step in minutes, k_{22} and k_{21} are experimentally-derived constants related to the thermal recovery of the transformer, τ_w is the winding time constant in minutes, $\Delta\theta_{hr}$ is hotspot-to-top-oil gradient at rated current in Kelvin, Ka is the load factor (current load/rated load), and y is the exponential power of current versus winding temperature rise (winding exponent). Similarly, $\Delta\theta_{h2}$ can be evaluated

$$\Delta\theta_{h2_{(n)}} = \Delta\theta_{h2_{(n-1)}} + \frac{Dt}{\frac{\tau_o}{k_{22}}} \times \left[(k_{21}-1) \times \Delta\theta_{hr} Ka^y - \Delta\theta_{h2_{(n-1)}}\right] \tag{8}$$

where τ_o is the average oil time constant in minutes. The top-oil temperature must be calculated and substituted back into (5)

$$\theta_{o_{(n)}} = \theta_{o_{(n-1)}} + \frac{Dt}{k_{11}\tau_o} \times \left[\left(\frac{(1+Kb^2R)}{1+R}\right)^x \times \Delta\theta_{or} - \left(\theta_{o_{(n-1)}} - \theta_a\right)\right]. \tag{9}$$

Equations (7) and (8) would be accurate if all phases of a three phase transformer are loaded identically or for single phase transformers which are commonly used in North America or in rural areas of Australia (e.g. SWER systems). However, the loads on the phases of the typical three phase distribution transformer are not balanced. It is possible to derive an expression analogous to (7) and (8) for each phase if the time varying loads on each phase are known.

The phase currents of the transformer would determine the winding to oil temperature differential of that phase so (8) could be rewritten for each individual phase

$$\Delta\theta_{h2_{(n)R}} = \Delta\theta_{h2_{(n-1)R}} + \frac{Dt}{\frac{\tau_o}{k_{22}}} \times \left[(k_{21}-1) \times \Delta\theta_{hr} K_R^y - \Delta\theta_{h2_{(n-1)R}}\right] \tag{10}$$

$$\Delta\theta_{h2_{(n)W}} = \Delta\theta_{h2_{(n-1)W}} + \frac{Dt}{\frac{\tau_o}{k_{22}}} \times \left[(k_{21}-1) \times \Delta\theta_{hr} K_W^y - \Delta\theta_{h2_{(n-1)W}}\right] \tag{11}$$

$$\Delta\theta_{h2_{(n)B}} = \Delta\theta_{h2_{(n-1)B}} + \frac{Dt}{\frac{\tau_o}{k_{22}}} \times \left[(k_{21}-1) \times \Delta\theta_{hr} K_B^y - \Delta\theta_{h2_{(n-1)B}}\right]. \tag{12}$$

The current load (I_{cl}) that would impact on the top oil temperature would be the rms value of each individual phase current at that given time

$$I_{cl}(t) = \sqrt{\left[I_{RMS}^A(t)\right]^2 + \left[I_{RMS}^B(t)\right]^2(t) + \left[I_{RMS}^C(t)\right]^2} \tag{13}$$

$$K_{ub} = \frac{I_{cl}(t)}{I_{rated}} \tag{14}$$

$$\theta_{o_{(n)}} = \theta_{o_{(n-1)}} + \frac{Dt}{k_{11}\tau_o} \times \left[\left(\frac{(1+K_{ub}^2R)}{1+R}\right)^x \times \Delta\theta_{or} - \left(\theta_{o_{(n-1)}} - \theta_a\right)\right]. \tag{15}$$

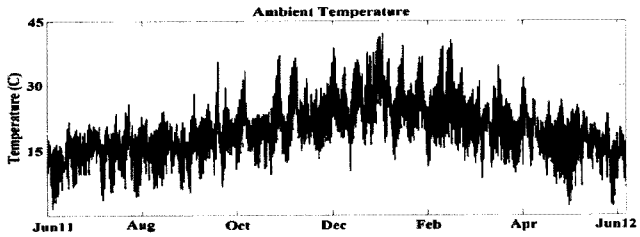

Fig. 3. Ambient temperature from June 2011 to July 2012.

C. Ambient Temperature and Roof top PV Generation

As described in the thermal model (9) and in publications [12], [18], the ambient temperature affects the hot spot temperature and impacts the life duration and the aging rate of transformer. Therefore as one of the input to the thermal model, one year ambient temperature data of July 2011–2012 were collected from Australian Bureau of Metrology Perth Airport weather station which is close to the high PV penetration trial [19]. The ambient temperature and solar irradiance was obtained at a 15-min rate to be consistent with the smart meter load data sampling times (Fig. 3).

D. Household Load Profiles

The transformer daily load curve is determined by the aggregated demand measured by the smart meters connected to individual consumers. In this work 15-min intervals are used, so a daily load curve is made up of 96 pairs of time and demand values. In order to guarantee a representative set of field data, a total of 365 days of measurements were collected from operating smart meters at the high PV penetration trial in Perth. A snapshot of all household load profiles (current) is shown in Fig. 4.

E. Distribution Transformers

The 102 node 400/230 V distribution network is connected to the high voltage 22 kV Western Australia's South-West Interconnected System (SWIS) through a 200 kVA distribution transformer that complies with the prevailing Australian Standard AS2374. Within the Western Power service area, approximately 17 000 distribution transformers are in service. More than 3,000 of these are 200 kVA units. These transformers are non-thermally upgraded paper and its life duration is 30 years. The loading patterns of the distribution transformer shown in Fig. 1 without and with rooftop PV generation is of interest in this study. The transformer ratings and impedance values are representative of current in-service distribution transformer types used in Western Australia. Transformer data are listed in Tables V and VII.

IV. Results and Discussion

A generalized analysis framework was developed to investigate the distribution transformer loss of life under proposed scenarios. In each scenario, the annual loss of life rate and the expected lifetime of the transformers were determined. These scenarios are:

1) unbalanced operating conditions (with solar input);
2) unbalanced operating conditions (no solar input);
3) balanced operating conditions (with solar input);
4) balanced operating conditions (no solar input).

A. Unbalanced Operating Conditions (With Solar Input)

To investigate the impact of PV on the life of the transformer, a one year set of 15-min measurements of transformer load and ambient temperature was assembled. Equations (1)–(5), together with transformer thermal parameters, were used to determine the transformer thermal response (Fig. 5). Equations (10)–(14) of Section III-D, were then used to obtain an LOL rate, and total LOL accumulated by the transformer over the given year.

The distribution transformer under study is substantially unbalanced. Out of 77 connected residential consumers, 13 are connected to phase A, 17 connected to phase while phase C is serving 21 customers and the 26 of the premises have three phase connection. Fig. 5 shows the temperature profiles corresponding to one summer week during the trial that includes the annual peak day for the transformer. The peak demand day occurred on the second day of a heat wave[1] and immediately preceded the Australia Day public holiday.

It is evident that phase C is heavily loaded. At the peak time the loading on phase C is 360 A/90 kVA or 1.34 p.u. and this value is close to the allowable maximum cyclic loading. In Australia it is acceptable practice to load a transformer up to 1.4 its rating for short period of time in a given year [20]. In this instance the utility company would not notice this overloading incident as the total energy sales from the transformer are used to predict peak loads. The energy sales are aggregated over the three phases, which at peak time was 196 kVA, and not the individual phase loading. Based on this approach the transformer will be kept in service until the total loading on it would reach 1.4 p.u. or 280 kVA, this assumption has been used as a basis to create four test cases. These investigate the LOL of the transformer if the loading on the transformer increases in 10% increments until it reaches the set value of 280 kVA (1.4 p.u.).

Case 1 illustrates the transformer HST and LOL quantities that correspond to the current unbalanced state of the transformer with 64 kW of PV. The results are presented for the peak day in the summer, Fig. 5(a) and Fig. 6(a) as well as for the day with lowest load in the winter, Fig. 5(b) and Fig. 6(b), for each phase of the transformer. The horizontal axis is the time of day in 15-min intervals. In Fig. 5 the vertical axis is HST, in Fig. 6 the vertical axis is LOL.

From Fig. 5 it is clear that the unbalance has caused different hotspot temperatures in each leg of the transformer. For example on the peak day the phase A winding would reach 90 °C whereas phase C winding exceeds 130 °C. This 40 °C temperature difference drives the rapid degradation of the phase C insulation. This temperature difference is much less at lighter loads (Fig. 6). As can be seen in Fig. 6 in the summer, the LOL is dominated by the higher transformer temperatures during the late afternoon and evening peak. Mention should be made of the high LOL rate of the phase C, in fact, it exceeds the design rate of 1-day per 24 h, by losing more than 3 days in 24 h. On the contrary, in winter,

[1]This discussion is based on the Bureau of Meteorology's definition of a heat wave as three or more consecutive days with daily maximum temperatures exceeding 35 °C.

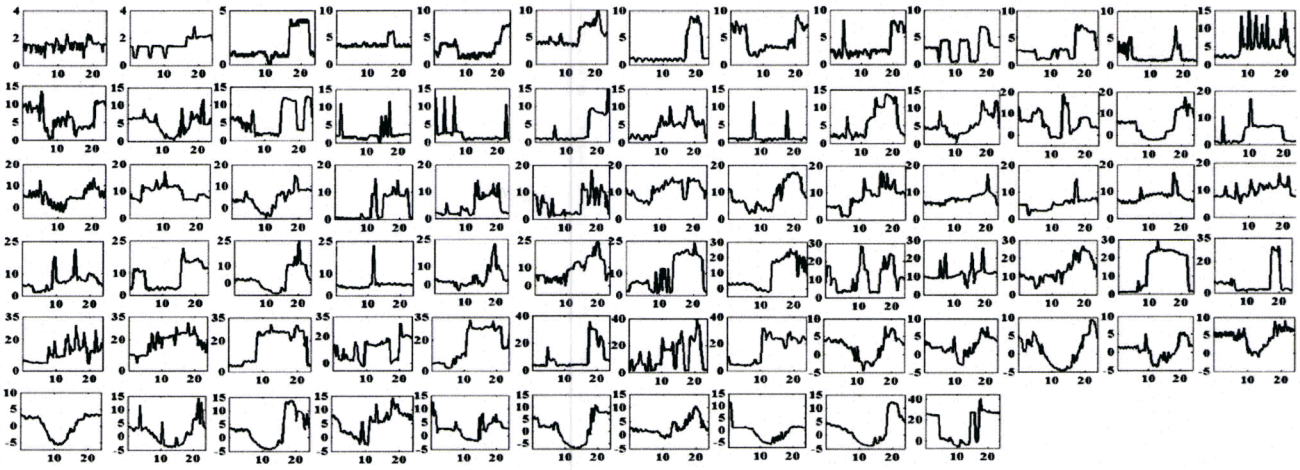

Fig. 4. Typical daily load profile of each of the 75 customers on Pavetta. (Vertical axis: Time (Hour); horizontal axis: Current (A)).

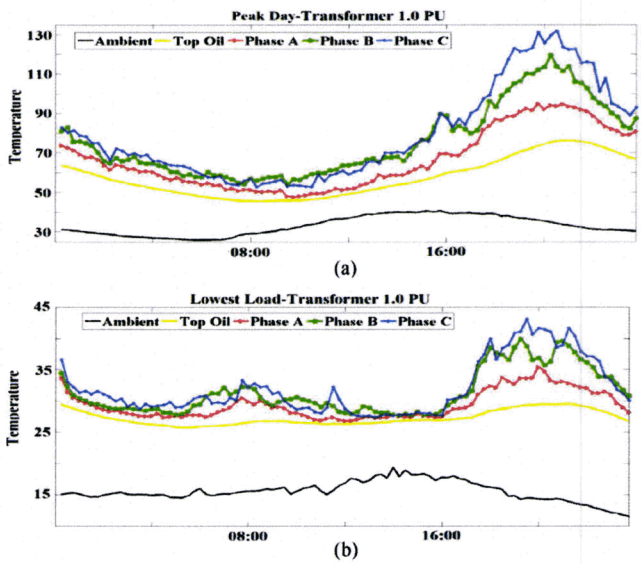

Fig. 5. Comparison of the daily evolution of the hotspot, top oil, and ambient temperature peak day (a) low load day (b).

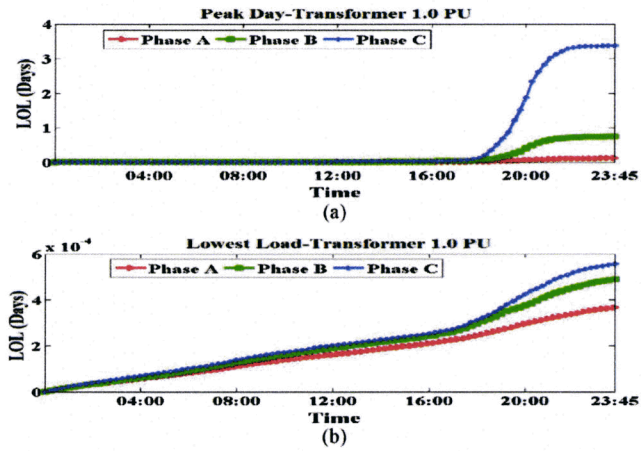

Fig. 6. Daily evolution of the loss of life on each phase of transformer, peak day (a) low load day (b).

the peak of the LOL rate is well below the designed value. This is due to the moderate loads combined with relatively low ambient temperature.

To see how future load growth would affect the transformer hot-spot temperature, simulations were carried out and compared together with the base load case (cases 2–4). For case 5, a worst case scenario is investigated by increasing the load to 1.4 p.u. (280 kVA).

Fig. 7 shows the top oil temperature and HST on the peak summer day when the transformer is loaded 40% above the nameplate 200 kVA rating and compares them with reference case. The oil reached 97°C and hot-spot temperatures for each phase reached 126 °C, 162 °C, and 185 °C, respectively. The HST limit of 160 °C was thus violated for both of the phases B and C, and rapid degradation is expected.

B. Unbalanced Operating Conditions (No Solar Input)

In order to demonstrate the benefit that roof top PV could provide in reducing the transformer loss of life, the solar generation was removed the system. The production pattern of PV units was obtained from the calculated and collected values using the solar irradiance measurements during the first three months of the trial (July–September 2011) and the smart meter data in 15-min interval during the rest of the period of the trial (October 2011–June 2012). For the first three months of the trial, only net household consumption data was available. In the last nine months of the trial, a two channel record of household load and solar generation was available for all single phase customers.

The solar generation profile of the first three months was estimated using solar irradiance, ambient temperature and rating information for the PV modules and inverter. The method was confirmed by correlating with generation pattern of the last nine months of the trial. Of the 34 premises with PV, 12 houses had dual reading meters that captured both the PV generation and consumption of the houses. The PV generation for the other 22

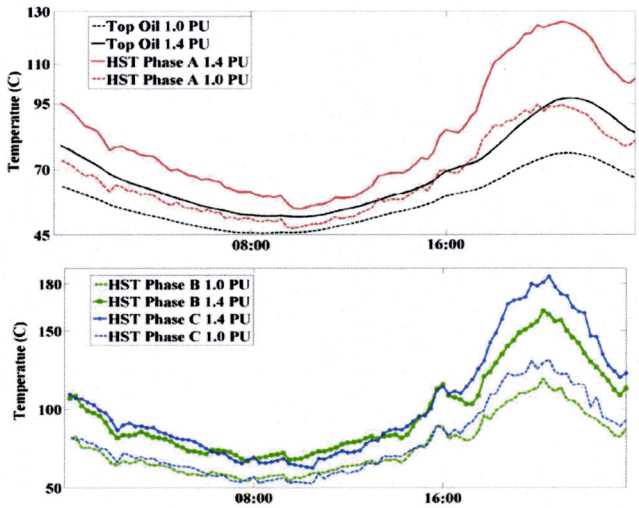

Fig. 7. Effect of possible load growth on TOT and HST.

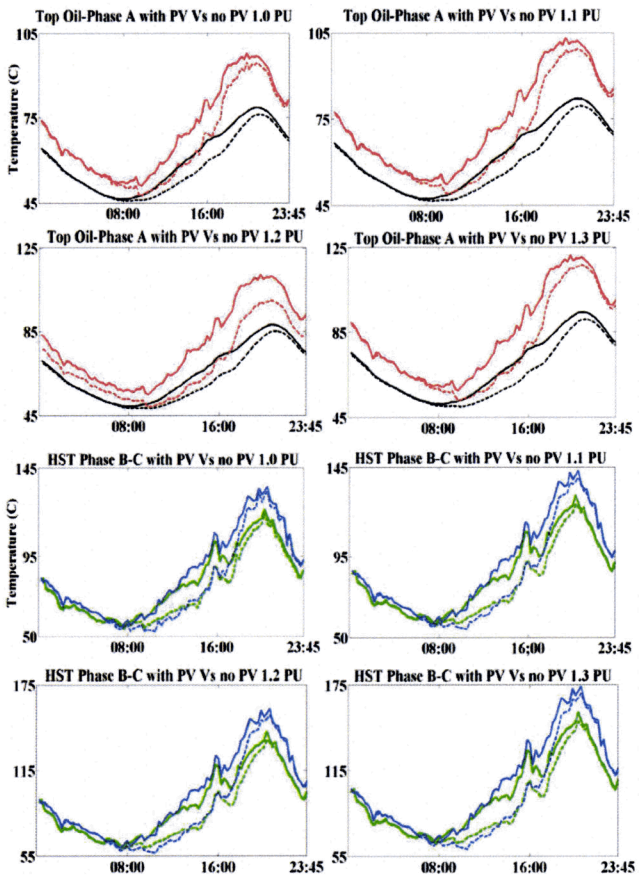

Fig. 8. Improvement in top oil temperature and HST in the presence of PV.

houses which only had net meter recording could be calculated from these observations.

The results for five operating conditions are shown in Fig. 8. In each graph the dotted line represents the system with the PV and the solid line the system without PV. The first row is the reference case (current state of the transformer), cases for additional loadings to 1.3 p.u. are shown in this figure. The final 1.4

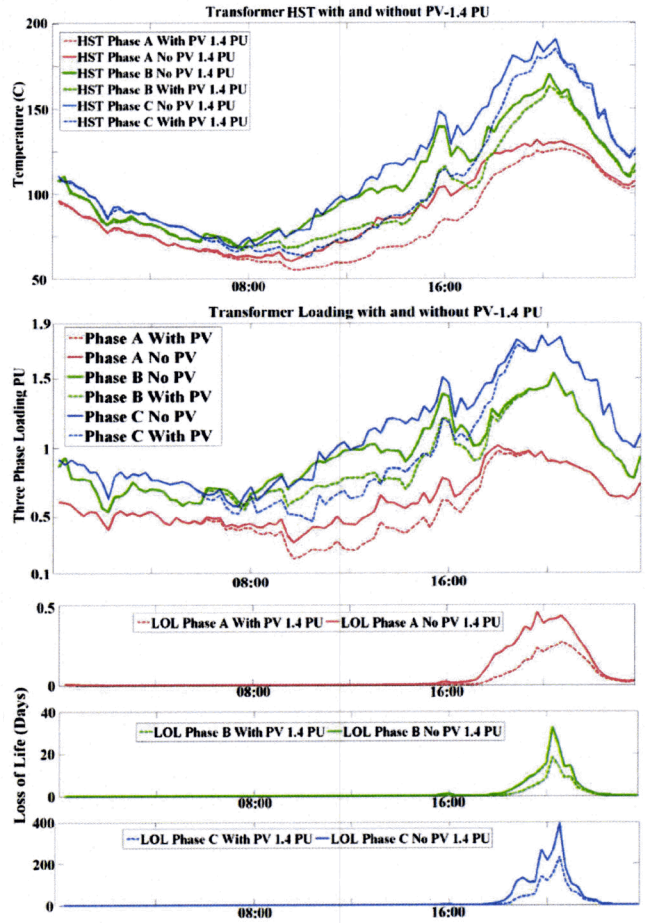

Fig. 9. Temperature difference in hot spot and oil of transformer and reduction in LOL as a result of PV generation.

p.u. loading case will be considered separately. Fig. 9 shows the temperature profiles corresponding to a peak transformer overload of 1.4 p.u.

Without PV generation, the oil and hot-spot temperatures reached 100 °C and 190 °C, respectively. The addition of 64 kW of PV generation lowered this to 180 °C for the HST and 95 °C for the top oil. These values are still extremely high. The PV benefit occurs during the time leading up to the peak. Lower loadings in the afternoon allow the transformer to enter the peak period with lower oil temperatures. In this example the LOL saving for Phase A, B, and C is 0.2,14, and 160 days for each phase, respectively. Except for cases where the PV installations are larger than the peak load, PV will decrease the daily top oil temperature and HST and extend transformer life. The extent of the improvement depends on the loading ratio of the transformer and the PV penetration level.

Table II provides a summary on each phase of transformer LOL and the benefit that roof top PV could provide to improve the transformer aging process based on its current and future loading. The first conclusion from Table II is that regardless of the operation scenario, the LOL rate of the transformer is far higher in summer. This may be due to the combined effect of higher ambient temperature and electricity use driven by cooling loads in this season. It further implies that roof top

TABLE II
SEASONAL VARIATION IN LOL OF TRANSFORMER

Transformer Loss of Life (Days)															
	Winter			Spring			Summer			Autumn			Annual		
	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C
Solar-1.0 pu	0.1	0.1	0.1	0.1	0.1	0.1	0.7	3.9	9.8	0.2	0.5	0.7	1.1	4.6	11
No solar-1.0 pu	0.1	0.1	0.1	0.1	0.1	0.2	1.2	6.8	18.5	0.3	1.1	1.6	1.7	8.1	20
Solar-1.1 pu	0.1	0.1	0.2	0.1	0.1	0.2	1.1	7.3	20.9	0.2	0.8	1.1	1.5	8.3	22
No solar-1.1 pu	0.1	0.1	0.2	0.1	0.2	0.2	1.8	13.2	41.5	0.4	2.0	3.0	2.4	15.5	45
Solar-1.2 pu	0.1	0.2	0.3	0.1	0.2	0.3	2.1	22.6	81.8	0.3	1.9	3.0	2.6	25	85
No solar-1.2 pu	0.1	0.2	0.3	0.1	0.2	0.4	3.8	43.5	173.3	0.8	6.0	9.6	4.8	50	184
Solar- 1.3 pu	0.2	0.3	0.6	0.1	0.3	0.5	4.5	79.9	365	0.6	5.2	8.8	5.4	86	375
No solar- 1.3 pu	0.2	0.3	0.6	0.1	0.4	0.8	8.8	161.7	820	1.6	19.4	34.1	11	182	855
Solar- 1.4 pu	0.3	0.5	1.3	0.1	0.4	0.4	10.3	318	1838	1.2	1.2	28.5	12	320	1868
No solar- 1.4 pu	0.3	0.5	1.2	0.2	0.7	1.7	22.1	670	4350	3.8	69.1	133	26	741	4486

TABLE III
LOSS OF LIFE IMPROVEMENT WITH PV GROWTH

Transformer Loading/ Phase C PV installation	TOT (Max) (°C)	HST (Max) (°C)	LOL (Days)
1.1 PU-26kW PV	79.5	137.9	22
1.1 PU-35 kW PV	77.1	130.6	14
1.2 PU-26kW PV	85	151.7	85
1.2 PU-40 kW PV	82.1	141.9	40

PV could provide a higher LOL reduction in the summer and is a suitable option for distribution transformer-life extension. The targeted installation of roof top PVs along the feeder, and even on a specific phase, could be considered as a life extension strategy. There are voltage rise limitations on the number and location of the installed roof top PVs. Considering this 7 additional PVs (with average rating of 1.88 kW) were randomly allocated to consumers on Phase C. Table III shows the corresponding life improvement.

C. *Balanced Operating Conditions (With Solar Input)*

In the first two scenarios the transformer was significantly unbalanced. In the last two scenarios examine the benefit of balanced operation with PV generation. Load balance can be achieved using a distribution STATCOM or optimal rephasing strategies with laterals or individual loads [21]–[23]. Phase identification systems introduced in [11], can be combined with rephrasing to improve balance. Fig. 10 compares the transformer peak day when the transformer is balanced to the current unbalanced case. The lower phase C current reduces the peak time HST to 115 °C from 130°C. A reduction of 15 °C in HST translates into reduction in LOL of approximately 2 days. It should be noted in Fig. 10 phase A and B would have experience higher temperatures and age faster. The benefit is that whole transformer will age at the same rate.

D. *Balanced Operating Conditions (No Solar Input)*

To conduct a comprehensive comparison, the daily HST and annual LOL rates were calculated when the transformer was balanced and had no PV connection. Table IV shows that the

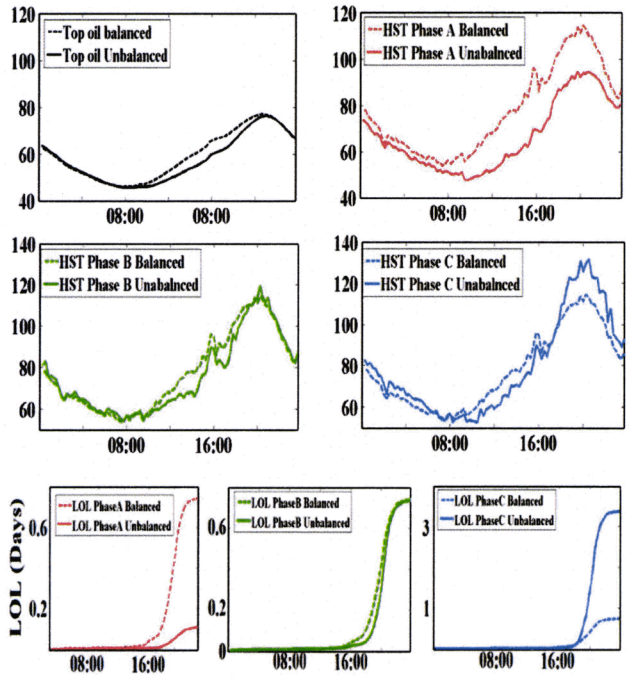

Fig. 10. Balanced versus unbalanced loading: HST, TOT and LOL.

transformer will suffer from rapid loss of life when the winding is under excessive stress. Balancing the phases will assure excessive LOL does not occur in one phase. Important benefits may be realized due to the life extension of distribution transformers brought about by customer-owned PV units even when the transformer is balanced.

It should be noted that under scenario 2, loading of 1.4 p.u., the transformer would lose more than 12 years of its life in one year. If the transformer was not upgraded it could reach its end of life within 1–2 years of operation.

V. CONCLUSION AND FUTURE WORK

PV generation will extend the life of oil-immersed distribution transformers even when the peak demand occurs well after sunset. The presented results correspond to a three phase residential transformer, but the result of this study could also be

TABLE IV
LOL UNDER DIFFERENT LOADING SCENARIOS (BALANCED VERSUS UNBALANCED)

Transformer Loading	Scenario A	Scenario B	Scenario C	Scenario D
1.0 pu	11	20	2.6	4.6
1.1 pu	22	45	6.6	12.2
1.2 pu	85	184	19.2	36.9
1.3 pu	375	855	63	125.2
1.4 pu	1868	4486	232	472

TABLE V
ELECTRIC CHARACTERISTICS OF THE TRANSFORMER UNDER STUDY

Property	Value	Property	Value
Apparent power	200 kVA	Secondary current	262.5 A
Cooling mode	ONAN	No-load loss	424 W
Primary voltage	22 kV	Load Loss	2963 W
Secondary voltage	415 V	Impedance	4.30 %
Primary current	5.25 A	Calculated % Io	0.614 %

TABLE VI
GEOMETRIC CHARACTERISTICS OF THE TRANSFORMER UNDER STUDY

Approximate Mass	Value
Untanked	700 kg
Tank and fittings	270 kg
Insulating liquid (Oil)	400/360 Litre/ kg
Transformer (Total)	1330 kg

TABLE VII
PARAMETERS FOR THE THERMAL MODEL OF THE 200-kVA TRANSFORMER

Symbol	Value	Symbol	Value	Symbol	Value
X	0.8	K_{22}	2	$\Delta\theta_{or}$	45 K
Y	1.6	R	6.98	τ_0	180 min
H	1.4	D_i	15min	τ_W	10 min
k_{11}	1	Gr	14.5 Ws/K		
K_{21}	1	$\Delta\theta_{br}$	35 K		

applied to single phase distribution transformers. The impact of PV on single phase distribution transformer (in the US, or SWER in Australia) is similar to the case when the three phase transformer is balanced (scenarios C and D). It is expected as the coincidence of PV with commercial load is higher better life extension will result for commercial load transformers.

The main focus of this paper is on the impact of PV on three phase transformer, but the method explored in this paper is applicable to any other form of single phase generator such as combined heat and power fuel cell modules, which are not dispatchable and are driven by the demand (i.e. hot water) of the household.

A thermal model was developed to assess the transformer temperatures over a 12 month cycle allowing a cumulative measure of loss of life to be determined for various scenarios. This paper is based on 15-min field data and captures the impact of solar variability at these time scales. The variations in irradiance produced by changes in cloud cover can cause faster fluctuations in the power generated by roof top PV. The short fluctuations (less than 15 min) would not have a significant effect on oil temperature (with time constant of 180 min) but could change the winding temperature in a magnitude of 2–3° (the winding time constant is 10 min). This will not significantly contribute to the aggregated loss of life given the short duration.

Finally the general trend of life improvement will increase with PV penetration until power flow reversals, comparable to the peak demand, occur. At this point the additional winding losses become significant.

ACKNOWLEDGMENT

The authors acknowledge the supply of consumption data collected under the Perth Solar City trial which is a part of the Australian Government's U.S.$94 million Solar Cities Program. The authors also acknowledge the support of Western Power in supplying network data, models and technical reports.

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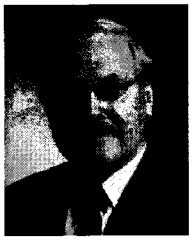

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Funding for the Harvard Electricity Policy Group over the course of its activities has been provided by the Mossavar-Rahmani Center for Business and Government of Harvard's Kennedy School of Government, and by the generous support of the following organizations:

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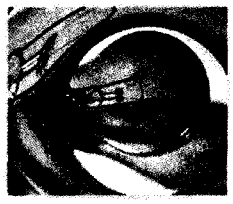

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission file number: 001-35758

SolarCity Corporation

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**02-0781046** **(I.R.S. Employer Identification Number)**

3055 Clearview Way
San Mateo, California 94402
(Address of principal executive offices and zip code)

Registrant's telephone number, including area code: (650) 638-1028

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	**The NASDAQ Stock Market LLC**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"). Yes ☐ No ☒

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2015 (the last business day of the registrant's most recently completed second fiscal quarter), the aggregate market value of voting stock held by non-affiliates of the registrant based on the closing price of $53.55 for shares of the registrant's common stock as reported by the NASDAQ Global Select Market, was approximately $3,281.8 million.

On January 31, 2016, 97,913,107 shares of the registrant's common stock, $0.0001 par value, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the information called for by Part III of this Form 10-K is hereby incorporated by reference from the definitive Proxy Statement for our annual meeting of stockholders, which will be filed with the Securities and Exchange Commission not later than 120 days after December 31, 2015.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The discussion in this annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Forward-looking statements are any statements that look to future events and consist of, among other things, our business strategies; anticipated future financial results; expected trends in certain financial and operating metrics; our belief that the aggregate megawatt production capacity of our systems is an indicator of the growth rate of our solar energy systems business; the calculation of estimated nominal contracted payments remaining, and certain other metrics based on forward-looking projections; projections on growth in the markets that we operate and our growth rates; pricing trends, including our ability to achieve economies of scale in both installation and capital costs; our ability to successfully integrate acquired businesses, operations and personnel; our ability to achieve manufacturing economies of scale and associated cost reductions; our goals reducing our cost per watt to $2.30 by 2017 and $2.00 by 2019; our expectations regarding the Riverbend Agreement, the development and construction of the Manufacturing Facility, anticipated timing and expense related to acquisition of manufacturing equipment, and related assumptions regarding expected capital and operating expenses and the performance of our manufacturing operations; our belief that adequate surplus capacity of non-tariff solar panels is available to suit our future needs and the costs of solar energy system components; our beliefs regarding future regulations and policies affecting our business, such as net energy metering policies; projections relating to our use of and reliance on U.S. Treasury grants and federal, state and local incentives and tax attributes; our regulatory status as a non-utility; our ability to continue to meet the regulatory requirements of a public company; domestic and international expansion, including throughout Mexico, and hiring plans; compliance with federal and international laws and regulations; product development efforts and customer preferences; the fair market value of our solar energy systems, including amounts potentially payable to our fund investors as a result of decreased fair market value determinations by the U.S. Treasury Department; the life and durability of our solar systems and equipment, anticipated contract renewals and warranty obligations; the success of our sales and marketing efforts; our internal control environment; pending litigation; the payment of future dividends; and our belief as to the sufficiency of our existing cash and cash equivalents, funds available under our secured credit facilities and funds available under existing financing funds to meet our working capital and operating resource requirements for the next 12 months.

The forward-looking statements are contained principally in, but not limited to, the sections titled "Risk Factors," and "Management's Discussion and Analysis of Financial Condition and Results of Operations." In addition, forward-looking statements also consist of statements involving trend analyses and statements including such words as "will," "may," "anticipate," "believe," "could," "would," "might," "potentially," "estimate," "continue," "plan," "expect," "intend," and similar expressions or the negative of these terms or other comparable terminology that convey uncertainty of future events or outcomes are intended to identify forward-looking statements. These forward-looking statements speak only as of the date of this annual report on Form 10-K and are subject to business and economic risks. As such, our actual results could differ materially from those set forth in the forward-looking statements as a result of a number of factors, including those set forth below in Part I, Item 1A, "Risk Factors," and in our other reports filed with the U.S. Securities and Exchange Commission. Moreover, we operate in a very competitive and rapidly changing environment, and new risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. In light of these risks, uncertainties, and assumptions, the forward-looking events and circumstances discussed in this report may not occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements. We undertake no obligation to revise or publically release the results of any revision to these forward-looking statements, except as required by law. Given these risks and uncertainties, readers are cautioned not to place undue reliance on such forward-looking statements.

PART I

ITEM 1. BUSINESS

Overview

SolarCity's founding vision is to accelerate mass adoption of sustainable energy. We believe solar power can and will become the world's predominant source of energy, and that we can speed widespread adoption of solar power by offering products that save our customers money. We sell renewable energy to our customers at prices below utility rates, and are focused on reducing the cost of solar energy. Since our founding in 2006, we have installed solar energy systems for over 230,000 customers. Our long-term agreements with our customers generate recurring payments and create a portfolio of high-quality receivables that we leverage to further reduce the cost of making the switch to solar energy.

We currently install more solar energy systems than any other company in the United States with over 110,000 new installations in 2015. During the first nine months of 2015, we installed approximately one-third of all residential solar energy capacity installed in the United States and approximately one-eighth of all commercial and industrial solar energy capacity in the United States, according to GTM Research, and we are the largest employer in the United States solar industry. Despite our growth, as of the end of 2015, the electricity produced by our solar installations represented less than 0.1% of total U.S. electricity generation. With over 37 million single-family homes in our primary service territories, and many millions more across the rest of the country and the world, our opportunity to expand is enormous and continues to grow.

Achieving our founding vision requires changing the way that electricity is produced and delivered. As part of this mission, we have set operational goals of reducing our cost per watt to $2.30 by 2017 and $2.00 by 2019. Accomplishing these goals requires efficient growth in our business through continued product and financing innovations, and a strong dedication to customer service.

2015 Operational Highlights:

Our 2015 operational highlights include the follow:

- Megawatts Installed – We installed 870 megawatts in the year ended December 31, 2015, an increase of 73.0% from the year ended December 31, 2014, and installed more solar energy systems than any other company in the United States in 2015.
- Healthy Balance Sheet – We had cash and cash equivalents of $382.5 million as of December 31, 2015.
- Solar Installations – We have installed 232,940 solar energy systems for our customers as December 31, 2015, an increase of 87.8% from fiscal 2014.
- Total Employees – We grew to 15,273 total employees as of December 31, 2015, an increase of 68.7% from fiscal 2014.
- International Expansion – In 2015, we expanded our solar installation business internationally into Mexico, with our acquisition of Ilioss in August 2015.
- Convertible Note Offerings – We issued $113 million in aggregate principal of zero coupon convertible senior notes due 2020 in a private placement transaction.
- Advancement in Rooftop Solar Panel Efficiency – In the fourth quarter of 2015, we announced that we had built what we believe to be the world's most efficient rooftop solar panel, with a module efficiency exceeding 22%, and began domestic manufacturing of our high-efficiency rooftop solar panels.
- Worldwide Microgrid Service – We launched GridLogic, a microgrid service that combines distributed energy resources (solar, batteries and controllable load) and can provide dependable, clean power to communities anywhere in the world vulnerable to power outages and high energy costs.
- Service Offering to SMBs – We partnered with Renew Financial to begin offering our energy contracts to small and medium-sized businesses, or SMBs, by allowing them to make payments through their property tax bills.

We believe the significant demand for our energy solutions results from the following value propositions:

- ***We lower energy costs***. We make it possible for our customers to switch to clean solar energy for less than they currently pay for electricity from utilities, with little to no up-front cost. Customers also are able to secure their energy costs for the long term and potentially insulate themselves from rising energy costs.
- ***We build long-term customer relationships***. We are focused on creating lifetime customer relationships. We offer solar energy on long-term customer agreements, typically with 20-year contract terms for SolarCity owned systems (with the potential to renew contracts at the end of the original term) and 30-year contract terms for customer-owned systems financed by SolarCity. These agreements reflect a position of trust in our customers' homes and businesses and generate significant referrals to new customers. Approximately one-out-of-five of our new residential sales in 2015 have come from referrals from other customers.
- ***We make it easy***. We perform the entire process – designing, permitting, financing, installing, maintenance and monitoring – and enable our customers to make the simple switch to renewable energy.
- ***We focus on quality***. Our top priority is to provide value and quality service to our customers. We have assembled a highly skilled team of in-house professionals dedicated to the highest engineering standards, overall quality and customer service during the installation process and throughout the entire life of the solar energy system.

Our Customers

Our customers purchase electricity and energy-related products and services from us that lower their overall energy costs. Our customer base is comprised of the following key sectors:

- *Residential*. The vast majority of our customers are individual homeowners who want to switch to cleaner, more affordable energy. Residential customers also include homeowners within communities developed by home builders we have partnered with.
- *Commercial*. Our commercial customers represent diverse business sectors, including technology, retail, manufacturing, agriculture and nonprofits, including large customers such as Walmart, eBay, HP, Walgreens, Intel, and Safeway, Mexican businesses such as Tiendas Soriana, and thousands of other businesses across the United States, including SMBs.
- *Government*. We have installed solar energy systems for various federal, state and municipal government entities, including the U.S. Air Force, Army, Marines and Navy, the City of Lancaster, the City of San Jose, the City of Sacramento, the Department of Homeland Security and a number of schools and universities.

We generally group our commercial and governmental customers together for our internal customer management purposes.

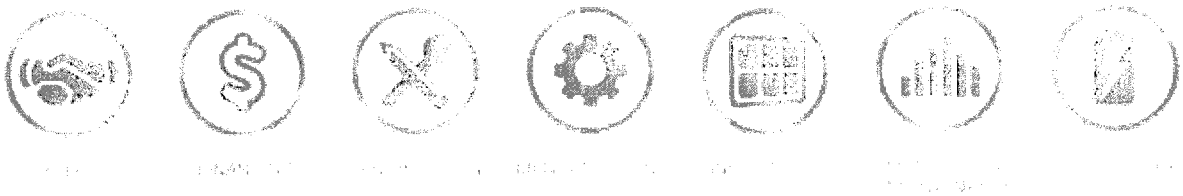
We have completed installations in 27 states, the District of Columbia, Puerto Rico, Canada and Mexico, and maintain operations centers across the United States. More than 70% of our current customers are in our top five states – California, Arizona, Massachusetts, Maryland and New York. We intend to expand our footprint domestically and internationally wherever distributed solar energy generation is a viable economic alternative to utility generation.

Our Approach

Through our uniquely vertically-integrated strategy, we enable our customers to lower their energy costs in a simple and efficient process. We have disrupted the industry status quo by providing renewable energy directly to customers for less than they are currently paying for utility-generated energy. Unlike utilities, we provide energy with a predictable cost structure that does not rely on limited fossil fuels and is insulated from rising retail electricity prices. We also provide assurances to our customers as to the amount of electricity produced by our solar energy systems. Our strategy is to create a best-in-class vertically-integrated operation focused on leveraging differentiated technology and our significant scale to lead the way in driving down the cost of solar energy to an affordable level for more and more people across the country and, eventually, the world. By focusing on technology solutions, we are working to build a cleaner, more affordable, more resilient energy distribution grid. By putting cleaner and more affordable energy in the hands of the consumer, we are building a broad portfolio of customers with relationships we aim to retain for life and ultimately a network of distributed solar energy systems that could transform the way energy is delivered globally.

The key elements of our integrated customer-focused approach are illustrated below:

SolarCity's Integrated Approach



- ***Sales***. We sell our products and services through a national sales organization that includes specialized internal call centers, a door-to-door sales team, a channel partner network and a robust customer referral program. We have structured our sales organization to efficiently engage prospective customers from initial interest to customized proposals to signed contracts. We intend to continue growing our sales teams as we focus on cost-efficient growth to educate consumers about the benefits of our solar products in order to lower customer acquisition costs and further expand our operations.
- ***Financing***. Financing makes it possible to install our solar energy systems for little or no upfront cost. Through a streamlined process, we provide multiple pricing options to our customers to help make renewable, distributed energy accessible and affordable, either on a fixed monthly fee basis or a fee based on the amount of energy produced. Our continued focus on innovative solar financing helps reduce our cost of capital and offers a range of payment alternatives to our customers.
- ***Engineering***. Our in-house engineering team designs a customized solar energy system for each of our customers. We have developed software that simplifies and expedites the design process and optimizes the design to maximize the energy production of each system. Our engineers complete a structural analysis of each building and produce a full set of structural design and electrical blueprints that contain the specifications for all system components.
- ***Manufacturing:*** In the fourth quarter of 2015, we announced that we had built what we believe to be the world's most efficient rooftop solar panel, with a module efficiency exceeding 22%, and began domestic manufacturing of our high-efficiency rooftop solar panels. We have also continued making innovations in solar mounting hardware, focusing on further reducing our installation time and costs.
- ***Installation***. Once we complete the design of our solar energy systems, we obtain all necessary building permits. Our customer care representatives coordinate the SolarCity team and continually update our customers every step through the project. We are a licensed contractor or use licensed subcontractors in every community we service, and we are responsible for every customer installation. For substantially all of our residential projects, we are the general contractor, construction manager and installer. For our commercial projects, we are in most cases the general contractor and construction manager and are increasing the integration of our commercial installation operations. Once we complete installation of a system, we schedule inspections with the local building department and arrange for interconnection to the power grid with the utility. By handling these logistics, we make the installation process simple for our customers.
- ***Monitoring and Maintenance***. Our proprietary monitoring software provides our customers with a real-time view of their energy generation and consumption. Our monitoring systems collect, monitor and display critical performance data from our solar energy systems, including production levels, local weather, electricity usage and environmental impacts. These monitoring systems allow us to confirm the continuing proper operation of our solar energy systems, identify maintenance issues and provide our customers with a better understanding of their energy usage, allowing them the opportunity to modify their usage accordingly. Our proprietary MySolarCity application offers an easy-to-read graphical display available on smartphones and any device with a Web browser, along with our proprietary EnergyExplorer that provides homeowners a self-guided tour of their energy usage, and MySystem which allows them to track their installation throughout the process.

- ***Energy Storage***. We also offer energy storage services through our collaboration with Tesla Motors. In March 2015, we announced our proprietary GridLogic microgrid service that combines distributed energy resources to enable a cleaner, more resilient and more affordable way of providing power. In April 2015, we announced a turnkey residential battery backup service that incorporates Tesla's Powerwall. We continue to see strong customer adoption of our DemandLogic smart energy storage system for commercial customers that allow businesses to reduce energy costs by using stored electricity generated by our solar energy systems to reduce peak demand from utilities.

Competitive Strengths

We believe the following strengths enable us to deliver our solar energy solutions to a diversified customer base that includes residential homeowners, large and small businesses, and government entities:

- ***Lower cost energy***. We provide energy to our customers at prices below utility rates. Our solar energy systems rely solely on the energy produced by the sun, allowing our customers to generate their own energy and reduce the amount they purchase from utilities. We help put solar energy generation within the reach of our customers by providing a variety of pricing options that minimize or eliminate upfront costs. Our customers typically achieve a lower overall electricity bill immediately upon installation. As retail utility rates rise, our customers' savings can generally increase.
- ***Easy to switch***. We have developed an integrated approach that allows our customers to access distributed renewable energy generation simply and efficiently. By providing the sales, financing, engineering, installation, monitoring and maintenance ourselves, we are able to control and oversee the entire process while providing a superior experience to our customers.
- ***Long-term customer relationships***. Our business model is centered on developing long-term relationships with our customers. Under our standard customer lease and power purchase agreements, our solar energy customers typically purchase energy from us for 20 years, and because our solar energy systems have an estimated life in excess of 30 years, we intend to offer our customers renewal contracts at the end of the original contract term. Under our MyPower product, we sell solar energy systems to our customers financed by a loan of up to 30 years. Under all our agreements, we maintain an ongoing relationship with our solar energy customers through our receipt of payments and our real-time monitoring systems.
- ***Significant size and scale***. Our status as the leading installer of solar energy systems in the United States enables us to achieve economies of scale in both installation and capital costs. We believe that our scale provides our customers with confidence in our continuing ability to service their system and guarantee its performance over the duration of their long-term contract.
- ***Innovative technology***. We continually innovate and develop new technologies to facilitate our growth and to enhance the delivery of our products and services. For example, we have developed proprietary software to reduce system design and installation, and we have acquired leading solar technology companies such as Zep Solar and Silevo.
- ***Brand recognition***. Our lifetime approach to customer relationships, our ability to provide high-quality services, and our dedication to best-in-class engineering efforts have helped us establish a recognized and trusted national brand. As one of the first companies to enter the solar leasing business and with the largest number of installations in the country by a wide margin, we have built a formidable track record of excellent workmanship and high customer satisfaction that is difficult for smaller, newer competitors to match. In 2015, approximately one-out-of-five of our new residential sales contracts originated from customer referrals. We believe our well-known brand and strong reputation are meaningful factors for customers as they consider their energy alternatives.
- ***Strong leadership team***. We are led by a strong management team with demonstrated execution capabilities and an ability to adapt to rapidly changing market environments. Our senior leadership team, consisting of our co-founders, Lyndon R. Rive and Peter J. Rive, and our chairman, Elon Musk, are widely recognized entrepreneurs and thought leaders with track records of building successful businesses. Additionally, to support our integrated business model, we have developed in-house expertise through strong senior leadership on our engineering, structured finance, legal and government affairs teams.

Our Financial Strategy and Product Offerings

SolarCity is an industry leader in offering innovative financing alternatives for our customers. In 2008, we launched the SolarLease, offering customers a fixed monthly fee at rates that typically translated into lower monthly utility bills with an electricity production guarantee from a SolarCity-owned system. This was followed in 2009 by the launch of the SolarPPA, a power purchase agreement charging customers a fee per kilowatt hour, or kWh, based on the amount of electricity produced by our solar energy systems at rates typically lower than their local utility rate. In 2014, we launched MyPower, a SolarCity-financed loan that offers the benefits of customer-owned systems. MyPower allows customers to

take direct advantage of federal tax credits to reduce their electricity prices, with monthly payments applied to the balance of the customer's outstanding loan. These money-saving product offerings have fueled our growth to date.

Our long-term customer agreements create high-quality recurring payments, investment tax credits, accelerated tax depreciation and other incentives. We perceive our recurring customer payments as high-quality assets because electricity is a necessity, and our customers typically include individuals with high credit scores, commercial businesses and government agencies. In addition, we have experienced extremely low historic default rates on payments from our customers, with average net loss rates in 2015 of approximately 0.5%. Our financial strategy is to monetize these assets at the lowest cost of capital. We share the economic benefit of this lower cost of capital with our customers by lowering the price they pay for energy.

Historically, we have monetized the assets created by our customer agreements through financing funds we have formed with fund investors. In general, we contribute and sell assets to the financing funds in exchange for upfront cash and a residual interest. The allocation of the economic benefits, as well as the timing of receipt of such economic benefits, among us and the fund investors varies depending on the structure of the financing fund. We use a portion of the cash received from the financing fund to cover our variable and fixed costs associated with installing the related solar energy systems. We invest the excess cash in the growth of our business. At the end of 2015, we had over 40 financing funds with 20 different investors, comprised mostly of large financial institutions and large blue chip corporations.

In 2013, we completed what we believe to be the first securitization of distributed solar energy assets, and we have followed our initial offering with four additional securitization offerings. In 2014, we launched our Solar Bonds program, offering investors the opportunity to purchase SolarCity debt securities directly from us through a web-based platform. In the future, in addition to or in lieu of monetizing our solar energy assets through financing funds, we may use debt, equity, securitization, joint-ventures and other financing strategies to fund our operations.

We are organized and operate in a single segment. See Note 2 to our consolidated financial statements included in Part II, Item 8 of this annual report on Form 10-K.

Our Innovative Products, Services and Technology

We use a portfolio of complementary products, services and technology innovations to reduce the cost and burdens of switching to solar energy, manage our growth and save our customers money.

- *Solar Energy Systems*. The major components of our solar energy systems include solar panels that convert sunlight into electrical current, inverters that convert the electrical output from the panels to a usable current compatible with the electric grid, racking that attaches the solar panels to the roof or ground and electrical hardware that connects the solar energy system to the electric grid and our monitoring device. We purchase the majority of system components from vendors, maintaining multiple sources for each major component to ensure competitive pricing and an adequate supply of materials. We also design and manufacture other system components.

  In the fourth quarter of 2015, we announced that we had built what we believe to be the world's most efficient rooftop solar panel, with a module efficiency exceeding 22%, and began domestic manufacturing of our high-efficiency rooftop solar panels. The SolarCity panel generates more power per square foot and harvests more energy over a year than any other rooftop panel in production.

- *Customer Agreements*

  - *SolarLease and SolarPPA Customer Agreements*. Our innovative SolarLease and SolarPPA customer agreements have fueled our growth by allowing our customers to pay little or no upfront costs to switch to distributed solar energy. Customers can also increase their lifetime energy savings by pre-paying a portion of their future payments. Over the terms of both agreements, we own and operate the system and guarantee its performance. Our current standard SolarLeases and SolarPPAs have 20-year terms, and we typically offer the opportunity to renew our agreements for up to an additional 10 years. Prior to 2010, our standard lease term was 15 years. In a limited number of utility districts, we continue to offer lease terms of less than 20 years to offer the maximum savings under applicable incentive programs. In addition, a limited number of our commercial customers have entered into power purchase agreements with terms of between 10 and 20 years.

  - *MyPower Loan Agreement*. Our first-of-its-kind MyPower product combines the benefits of our SolarPPA with financing directly through SolarCity. Under MyPower, we operate and maintain the system through the 30-year term of the agreement. MyPower allows us to broaden our customer base to customers

preferring system ownership and expand our markets to jurisdictions less favorable to third-party owned systems.

- *Grid Control / Energy Storage Systems*. We are also developing proprietary battery management systems built on our solar energy monitoring communications backbone. These battery management systems are designed to enable remote, fully bidirectional control of distributed energy storage that can potentially provide significant benefits to our customers, utilities and grid operators. The benefits to our customers of energy storage coupled with a solar energy system may include back-up power, time-of-use energy arbitrage, rate arbitrage, peak demand shaving and demand response. The benefits to utilities and grid operators may include more stable grid management and improved up-time. We believe that advances in battery storage technology, steep reductions in pricing and burgeoning policy changes that support energy storage hold significant promise for enabling deployments of grid-connected energy storage systems.
- *Zep Solar Mounting Systems*. Our Zep Solar division designs complementary mounting and grounding hardware. Zep Solar's engineering team is dedicated to state-of-the-art innovations to reduce the cost of installing solar energy systems and increase their productivity. Our ZS Peak flat roof solar mounting solution has increased our ability to serve commercial customers by reducing installation times and increasing the electricity generation and panel capacity of our system layouts.
- *Proprietary Software*
  - *SolarBid Sales Management Platform*. SolarBid is our proprietary sales management platform that incorporates a database of rate information by utility, sun exposure, roof orientation and a variety of other factors to enable a detailed analysis and customized graphical presentation of each customer's savings. SolarBid simplifies the sales process and automates pricing, system configuration and proposal generation. It also automatically prepares the customer agreements, incentive forms and utility paperwork required to complete a project. SolarBid is designed for maximum flexibility, allowing us to quickly add new products, services and geographies.
  - *SolarWorks Customer Management Software*. SolarWorks is our proprietary software platform used to track and manage every project. SolarWorks' embedded database and custom architecture offers reduced costs, improved quality and improved customer experience by supporting scheduling, budgeting and other project management functions as well as customer communications, inventory management and detailed project data.
  - *Energy Designer*. Energy Designer is a proprietary software application used by our field engineering auditors to rapidly collect all pertinent site-specific design details on a tablet computer. This information then syncs with our design automation software, reducing design time and accelerating the permitting process.
  - *PowerGuide Proactive Monitoring Solutions*. SolarGuard and PowerGuide provide our customers a real-time view of their home's or business's energy generation and consumption. Through easy-to-read graphical displays available on smartphones and any device with a web browser, our monitoring systems collect, monitor and display critical performance data from our solar energy systems, including production levels, local weather, electricity usage and environmental impacts such as carbon offset and pollution reduction. Our customer service team reviews system performance data using this proprietary monitoring software to confirm continued efficient operation.

Sales and Marketing

We market and sell our products and services through a national sales organization that includes a direct outside sales force, a door-to-door sales force, call centers, a channel partner network and a robust customer referral program.

- *Direct Outside Sales Force*. Our outside sales force typically resides and works within the markets we serve. Our outside sales force allows us to sell to those customers who prefer a face-to-face interaction.
- *Call Centers*. Our call centers allow us to sell our energy products and services to customers without visiting their homes or businesses. Because every home or site is unique, we begin by talking with each prospective customer about their energy needs and savings goals. Then, using online satellite technology, our salesperson evaluates the suitability of the site for our products and services. If a solar energy system is an appropriate solution, our salesperson collects preliminary utility usage data and site information, and ultimately, provides a preliminary estimate of costs. If the customer desires to work with us, contracts can then be executed with e-signatures.

- *Door-to-Door Sales Force.* Our door-to-door sales force consists of trained salespersons that identify and educate potential customers about our product and service offerings. As solar energy remains a new commodity for many homeowners, our trained sales force can help reach families that may not have considered solar energy.
- *Channel Partner Network*

- *The Home Depot*. Our products and services are available through The Home Depot stores located in most states where we have significant operations. We are the exclusive solar provider in the stores we serve. We primarily sell through a team of field energy specialists that speak to and qualify prospective customers in stores. In addition, we sell through point-of-purchase displays in the stores, and through other direct marketing strategies including in-store flyers, seminars, promotions, retail signage and displays, and a co-branded website.
- *Best Buy*. We also offer our products and services in over 200 Best Buy stores across the nation, where SolarCity representatives are available to evaluate the feasibility of installing a residential solar energy system.
- *Homebuilder Partners*. Our products and services are available through a number of regional and national new home builders, including Shea Homes, Pulte, Taylor Morrison and Del Webb. These partners market solar energy systems through a variety of strategies, including advertising within their model homes, signage within their communities, realtor emails, newspaper inserts, online banners and co-branded flyers. Certain of these partners pre-pay for the electricity that will be produced by the solar energy system installed on the new home they sell, using the benefit of pre-paid solar energy as a selling point.
- *Other Channel Partners*. Our products and services are also available through partnerships with Tesla Motors, Direct Energy, Honda, Acura and BMW.

- *Solar Ambassador Program*. In 2014, we launched our Solar Ambassador program. The program is a network marketing program in which interested ambassadors are engaged as independent contractors to promote the benefits of solar energy and become eligible to receive cash rewards through customer referrals that result in the successful installation of solar energy systems.

We also market our products and services through a variety of direct marketing strategies designed to reach qualified homeowners and businesses, including radio ads and public radio sponsorships, newspaper and magazine ads, online banner ads, search engine marketing, direct mail, participation in trade shows, events and home shows, email marketing, public relations, social media, sweepstakes and promotions, newsletters, community programs and field marketing techniques. Our in-house marketing team manages and coordinates our media buying and customizes our content for each region.

Operations and Suppliers

We purchase major components such as solar panels and inverters directly from multiple manufacturers. We screen these suppliers and components based on expected cost, reliability, warranty coverage, ease of installation and other ancillary costs. As of December 31, 2015, our primary solar panel suppliers were Canadian Solar Inc., Trina Solar Limited, AUO Green Energy America Corp., REC Americas LLC, Hanwa Qcells America and Kyocera Solar, Inc., among others, and our primary inverter suppliers were ABB Inc., SolarEdge Technologies, Inc., Fronius USA, LLC, and Solectria Renewables, LLC, among others. We typically enter into master contractual arrangements with our major suppliers that define the general terms and conditions of our purchases, including warranties, product specifications, indemnities, delivery and other customary terms. We typically purchase solar panels and inverters on an as-needed basis from our suppliers at then-prevailing prices pursuant to purchase orders issued under our master contractual arrangements. While we generally do not enter into arrangements containing long-term pricing or volume commitments, we have entered into several long-term purchase commitments to procure solar panels, system components and other commodities, and we may increasingly do so in the future.

Our racking and mounting systems are manufactured by our Zep Solar subsidiary, as well as other contract manufacturers using our design.

We maintain over 80 centralized operations and maintenance facilities and a fleet of approximately 4,300 trucks and other vehicles to support our rapidly growing business. In California, our operations and maintenance facilities allow us to service more than 95% of the state's population. This operational scale is fundamental to our business, as our field teams currently complete over 8,000 residential solar energy system installations each month, while our project management teams simultaneously manage thousands of projects as they move through the stages of engineering, permitting, installation and monitoring.

We offer a range of warranties and performance guarantees for our solar energy systems. We generally provide warranties of between 10 to 30 years on the generating and non-generating parts of the solar energy systems we sell, together with a pass-through of the inverter and module manufacturers' warranties that generally range from 5 to 30 years. Where we sell the electricity generated by a solar energy system, we compensate customers if their system produces less energy over a specified performance period than our guarantee. We also provide ongoing service and repair during the entire term of the customer relationship. Costs associated with such ongoing service and repair have not been material to date, but are expected to increase as our customer base expands, inverters require replacement and the systems age.

Competition

We believe our primary competitors are the traditional local utilities that supply energy to our potential customers. We compete with these traditional utilities primarily based on price, predictability of price and the ease by which customers can switch to electricity generated by our solar energy systems rather than fossil based alternatives. We believe that our favorable pricing and focus on lifetime customer relationships allows us to compete favorably with traditional utilities in the regions we service.

We also compete with companies that provide products and services in distinct segments of the downstream solar energy and energy-related products value chain. Many companies only install solar energy systems, while others only provide financing for these installations. In the residential solar energy system installation market, our primary competitors include Vivint Solar Inc., Sunrun Inc., NRG Home Solar, Sungevity, Inc., Trinity Solar, Verengo, Inc., and many smaller local solar companies. In the commercial solar energy system installation market, our competitors include SunPower Corporation, SunEdison LLC, Borrego Solar Systems, Inc., G&S Solar Installers, Cenergy Power and numerous other companies.

We believe that our favorable pricing, focus on lifetime customer relationships, and integrated customer-facing approach to delivering solar energy allows us to compete favorably with these companies. While we offer in-house sales, financing, engineering, installation, monitoring, and operations and maintenance, many of our competitors offer only a subset of the products and services we provide.

Intellectual Property

Our intellectual property is an essential element of our business, and our success depends, at least in part, on our ability to protect our core technology and intellectual property. To accomplish this, we rely on a combination of patent, trade secret, trademark, copyright and other intellectual property laws, confidentiality agreements and license agreements to establish and protect our intellectual property rights.

As of December 31, 2015, SolarCity and our wholly owned subsidiaries had 76 issued patents and 250 patent applications pending with the U.S. Patent and Trademark Office, 56 patents issued/registered and 111 patent applications pending with foreign patent and trademark offices, and 47 trademark registrations and 55 pending trademark applications. These patents and applications relate to various SolarCity technologies, such as solar cells, installation and mounting hardware, financial products, monitoring solutions and related software. Our issued patents start expiring in 2025. SolarCity intends to continue to file additional patent applications. "SolarCity," "SolarCity and Sun logo," "SolarGuard," "SolarLease," "PowerGuide," "SunRaising," "Rooftop Rewards," "Solar Made Simple," "Energy Explorer," "Zep Solar," "Zep Compatible," "Zep Groove," "Silevo," "Triex," and "Ilioss" are among SolarCity's registered trademarks in the United States and, in some cases, in certain other countries. SolarCity's other unregistered trademarks and service marks in the United States include: "Power Forever," "Better Energy," "SolarBid," "SolarWorks" and "DemandLogic."

All of our employees and independent contractors are required to sign agreements acknowledging that all inventions, trade secrets, works of authorship, developments and other processes generated by them on our behalf are our property and assigning to us any ownership that they may claim in those works.

Securing Our Solar Energy Systems

Unless a customer fully prepays for a solar energy system, we file a uniform commercial code financing statement, or UCC-1, on the systems in the real property records where each system is located prior to or when the system is installed. We file the UCC-1 to provide notice of our interests in the solar energy system to anyone who might perform a title search on the address where the system is located. For loans financed by SolarCity, we also file the UCC-1 with the applicable state's secretary of state.

A UCC-1 fixture filing is not a lien against a customer's home and does not entitle us to the proceeds of the sale of a home in foreclosure. Typically, when a foreclosed home is sold by the lender, we negotiate with the prospective buyer to assume the existing agreement. We believe the prospective buyer is generally motivated to assume the existing agreement to receive its benefits. The number of solar energy systems identified for recovery has been immaterial to date.

Government Regulation

We are not a "regulated utility" in the United States under applicable national, state or other local regulatory regimes where we conduct business. For our limited operations in Ontario, Canada, our subsidiary is subject to the regulations of the relevant energy regulatory agencies applicable to all producers of electricity under the relevant feed-in tariff, or FIT, regulations, including the FIT rates.

To operate our systems, we obtain interconnection agreements from the applicable local primary electricity utility. Depending on the size of the solar energy system and local law requirements, interconnection agreements are between the local utility and either us or our customer. In almost all cases, interconnection agreements are standard form agreements that have been pre-approved by the local public utility commission or other regulatory body with jurisdiction over interconnection agreements. As such, no additional regulatory approvals are required once interconnection agreements are signed. We maintain a utility administration function, with primary responsibility for engaging with utilities and ensuring our compliance with interconnection rules.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the occupational health and safety of our employees, wage regulations and environmental regulations. For example, we are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that protect and regulate employee health and safety. Our increased manufacturing operations also subject us to a number of environmental health and safety regulations. We have a robust safety department led by safety professionals, and we expend significant resources to comply with these regulations, requirements and industry best practices.

Federal and/or state prevailing wage requirements, which generally apply to any "public works" construction project that receives public funds, may apply to installations of our solar energy systems on government facilities. The prevailing wage is the basic hourly rate paid on public works projects to a majority of workers engaged in a particular craft, classification or type of work within a particular area. Prevailing wage requirements are established and enforced by regulatory agencies. Our in-house prevailing wage personnel monitor and coordinate our continuing compliance with these regulations.

Government Incentives

U.S. federal, state and local governments have established various policies, incentives and financial mechanisms to reduce the cost of solar energy and to accelerate the adoption of solar energy. These incentives include tax credits, cash grants, tax abatements and rebates. These incentives help catalyze private sector investments in solar energy, energy efficiency and energy storage measures, including the installation and operation of residential and commercial solar energy systems.

The federal government currently provides an uncapped investment tax credit, or Federal ITC, under two sections of the Internal Revenue Code of 1986, as amended, or IRC: Section 48 and Section 25D, both of which were modified and extended at the end of 2015.

Section 48(a)(3) of the IRC allows a taxpayer to claim a credit of 30% of qualified expenditures for a commercial solar energy system that commences construction by December 31, 2019. The credit then declines to 26% for systems that commence construction by December 31, 2020 and to 22% for systems that commence construction by December 31, 2021. The credit is scheduled to decline to a permanent 10% effective January 1, 2022. Historically, we have utilized the Section 48 commercial credit when available for both our residential and commercial projects, based on ownership of the solar energy system. The federal government also provides accelerated depreciation for eligible commercial solar energy systems. Department of Treasury regulations detailing how the commence construction requirements can be satisfied are expected by the end of the first quarter of 2016.

Section 25D of the IRC allows a taxpayer to claim a credit for a residential solar energy system that is owned by the homeowner. This credit is available at 30% for systems that are placed in service by December 31 2019, at 26% for systems placed in service in 2020, and at 22% for systems placed in service in 2021. The credit is scheduled to expire effective January 1, 2022. MyPower customers can currently claim the Section 25D investment tax credit. Customers who purchase their solar energy systems for cash are also eligible to claim the Section 25D investment tax credit.

Approximately half of U.S. states offer a personal and/or corporate investment or production tax credit for solar, which are additive to the Federal ITC. Further, more than half of U.S. states, and many local jurisdictions, have established property tax incentives for renewable energy systems, which include exemptions, exclusions, abatements and credits.

Many state governments, investor-owned utilities, municipal utilities and co-operative utilities offer rebates or other cash incentives for the installation and operation of a solar energy system or energy-related products. Capital costs or "up-

front" rebates provide payments to solar customers based on the cost, size or expected production of a customer's solar energy system. Performance-based incentives provide cash payments to a system owner based on the energy generated by their solar energy system during a pre-determined period, and they are paid over that time period. Some states and utilities also have established feed-in tariff programs that are a type of performance-based incentive where the system owner-producer is paid a set rate for the electricity their system generates and exports to the grid over a set period of time.

Forty-one states, Washington, D.C. and Puerto Rico have a regulatory policy known as net energy metering, or net metering, available to new customers. Net metering typically allows SolarCity's customers to interconnect their on-site solar energy systems to the utility grid and offset their utility electricity purchases by receiving a bill credit at the utility's retail rate for energy generated by their solar energy system that is exported to the grid in excess of electric load used by customers. Each of the states where we currently serve customers has adopted a net metering policy except for Texas, where certain individual utilities have adopted net metering or a policy similar to net metering. Typically, at the end of the billing period, the customer simply pays for the net energy used or receives a credit at the retail rate if more energy is produced than consumed.

Some states have established limits on net metering. For example, in October 2015, the Hawaii Public Utilities Commission capped the state's net metering program at existing levels and net metering no longer is available to new customers. In late-December 2015, the Nevada Public Utilities Commission also effectively capped the state's net metering program at existing levels and net metering no longer is available to new customers. In addition, the new rules adopted by the Nevada Public Utilities Commission include significant additional monthly charges on customers who interconnect their solar energy systems, a significant reduction in the amount of bill credit customer receive for energy generated by their solar energy system that is exported to the grid in excess of electric load used by customers, and application of the new rules to existing customers with solar energy systems. These actions have been criticized by solar and customer protection groups and we have challenged these new rules and their application to existing customers in filings with the Nevada Public Utilities Commission.

California investor-owned utilities are currently required to provide net metering to their customers until the total generating capacity of net metered systems exceeds 5% of the utilities' "aggregate customer peak demand." In January 2016, the California Public Utilities Commission established a new net metering program requiring that customers utilize a time-of-use tariff, with no participation cap that will apply after the current 5% cap is reached. Other states, such as New York and New Jersey, recently have increased their respective limits on net metering.

Sales of electricity and non-sale equipment leases by third parties face regulatory challenges in some states and jurisdictions, and our leases and power purchase agreements are third-party ownership arrangements. Other challenges pertain to whether third-party owned systems qualify for the same levels of rebates or other non-tax incentives available for customer-owned solar energy systems, and whether third-party owned systems are eligible for these incentives.

Many states also have adopted procurement requirements for renewable energy production. Twenty-nine states and Washington, D.C. have adopted an enforceable renewable portfolio standard, or RPS, or other mandated renewable capacity policy that requires covered entities to procure a specified percentage of total electricity delivered to customers in the state from eligible renewable energy sources, such as solar energy systems, by a specified date. In addition, seven other states have set voluntary goals for renewable generation. Roughly one-third of states with RPS policies require a minimum portion of the RPS be met by solar, or customer-generated solar, with substantial penalties for non-compliance. To prove compliance with such mandates, utilities typically must surrender renewable energy certificates, or RECs, to system owners, who often are able to sell RECs to utilities directly or in REC markets.

Employees

As of December 31, 2015, we had 15,273 total employees, of whom 15,219 were full-time employees. Approximately 6,873 worked in operations, installations and manufacturing; 5,661 in various sales and marketing related departments and 2,739 in general and administrative and research and development related departments. In January 2016, following the recent actions by the Nevada Public Utilities Commission, we were forced to eliminate more than 550 jobs in Nevada, primarily affecting personnel in operations, installations and manufacturing, as well as sales and marketing related departments. As of the date of this Annual Report, we are focused on relocating employees to other states and positions and reducing the impact of these job eliminations on our employees. Our employees are not currently represented by any labor union or subject to any collective bargaining agreement. We have not experienced any work stoppages, and we consider our relationship with our employees to be good.

Corporate Information

We were incorporated in June 2006 as a Delaware corporation. Our headquarters are located at 3055 Clearview Way, San Mateo, California 94402, and our telephone number is (650) 638-1028. You can access our website at

www.solarcity.com. Information contained on our website is not a part of, and is not incorporated into, this annual report on Form 10-K, and the inclusion of our website address in this annual report on Form 10-K is an inactive textual reference only. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to reports filed or furnished pursuant to Sections 13(a) and 15(d) of the Exchange Act are available free of charge on the Investors portion of our web site as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

You should carefully consider the risks described below, together with the other information contained in this annual report on Form 10-K, including our consolidated financial statements and related notes, before investing in our common stock. The risks described below are not the only risks facing our company. Any of the following risks and additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially and adversely affect our business, financial condition, results or operations. In such case, you may lose all or part of your original investment.

Risks Related to our Operations

Existing electric utility industry regulations, and changes to regulations, may present technical, regulatory and economic barriers to the purchase and use of solar energy systems that may significantly reduce demand for our solar energy systems or adversely impact the economics of existing energy contracts.

Federal, state and local government regulations and policies concerning the electric utility industry, utility rate structures, interconnection procedures, internal policies and regulations promulgated by electric utilities, heavily influence the market for electricity generation products and services. These regulations and policies often relate to electricity pricing and the interconnection of customer-owned electricity generation. In the United States, governments and utilities continuously modify these regulations and policies. These regulations and policies could deter potential customers from purchasing renewable energy, including solar energy systems. This could result in a significant reduction in demand for our solar energy systems. For example, utilities commonly charge fees to large, industrial customers for disconnecting from the electric grid or for having the capacity to use power from the electric grid for back-up purposes. These fees could increase our customers' cost to use our systems and make our product offerings less desirable, thereby harming our business, prospects, financial condition and results of operations. In addition, depending on the region, electricity generated by solar energy systems competes most effectively with higher priced peak-hour electricity from the electric grid, rather than the lower average price of electricity. Modifications to the utilities' peak-hour pricing policies or rate design, such as a flat rate, would require us to lower the price of our solar energy systems to compete with the price of electricity from the electric grid.

Future changes to government or internal utility regulations and policies that favor electric utilities could also reduce our competitiveness, cause a significant reduction in demand for our products and services, and threaten the economics of our existing energy contracts. For example, in October 2015, the Hawaii Public Utilities Commission capped the state's net metering program at existing levels and net metering no longer is available to new customers. In late-December 2015, the Nevada Public Utilities Commission also effectively capped the state's net metering program at existing levels and net metering no longer is available to new customers. In addition, Nevada's new rules include significant additional monthly charges on customers who interconnect their solar energy systems, significant reduction in the amount of bill credit for energy generated by their solar energy system that is exported to the grid in excess of electric load used by customers, and application of the new rules to existing customers with solar energy systems. These new rules and their application to existing customers have been challenged in filings with the Nevada Public Utilities Commission and we intend to pursue available remedies under state law, if necessary. As a result of these new rules we have ceased our sales and installation operations in Nevada. If these new rules are imposed as adopted, the new rules are not overruled legislatively, and challenges to these new rules are unsuccessful, demand for solar energy systems and services in Nevada will likely be significantly impaired, and we could see an increase in the default rate of existing energy contracts or we may find it necessary to renegotiate our pricing of affected customers.

In other jurisdictions, it has been proposed that additional fees and other charges be assessed on customers purchasing energy from solar energy systems. In particular, the Salt River Project, or SRP, in Arizona has imposed anticompetitive penalties on new solar customers in an attempt to exclude rooftop solar, and in response in March 2015 we filed a lawsuit in federal court in Arizona, asking the court to stop SRP's anti-competitive behavior. In the event that effective net metering programs are limited in California and other key markets or any such fees or charges are imposed, our ability to attract new customers and compete with the price of electricity generated by local utilities in these jurisdictions may be severely limited, and such unaccounted for increases in the fees or charges applicable to existing customer agreements may increase the cost of energy to those customers and result in an increased rate of defaults under our customer agreements. Any of these results could reduce demand for our solar energy systems, harm our business, prospects, financial condition and results of operations.

We rely on net metering and related policies to offer competitive pricing to our customers in some of our key markets.

Forty-one states, Washington, D.C. and Puerto Rico have a regulatory policy known as net energy metering, or net metering, available to new customers. Each of the states where we currently serve customers has adopted a net metering policy except for Texas, where certain individual utilities have adopted net metering or a policy similar to net metering. Net metering typically allows our customers to interconnect their on-site solar energy systems to the utility grid and offset their utility electricity purchases by receiving a bill credit at the utility's retail rate for energy generated by their solar energy system that is exported to the grid in excess of the electric load used by the customers. At the end of the billing period, the customer simply pays for the net energy used or receives a credit at the retail rate if more energy is produced than consumed. Utilities operating in states without a net metering policy may receive solar electricity that is exported to the grid when there is no simultaneous energy demand by the customer without providing retail compensation to the customer for this generation.

Our ability to sell solar energy systems and the electricity they generate may be adversely impacted by the failure to expand existing limits on the amount of net metering in states that have implemented it, the failure to adopt a net metering policy where it currently is not in place, the imposition of new charges that only or disproportionately impact customers that utilize net metering or reductions in the amount or value of credit that customers receive through net metering. Our ability to sell solar energy systems and the electricity they generate may also be adversely impacted by the unavailability of expedited or simplified interconnection for grid-tied solar energy systems or any limitation on the number of customer interconnections or amount of solar energy that utilities are required to allow in their service territory or some part of the grid. For example, in October 2015, the Hawaii Public Utilities Commission capped the state's net metering program at existing levels, and in late-December 2015, the Nevada Public Utilities Commission effectively capped the state's net metering program at existing levels and imposed additional monthly charges on customers who interconnect their solar energy systems. In addition, utilities in some states, such as SRP in Arizona, have proposed imposing additional monthly charges on customers who interconnect solar energy systems installed on their homes. If such charges are imposed, the cost savings associated with switching to solar energy may be significantly reduced and our ability to attract future customers and compete with traditional utility providers could be impacted. If such charges are imposed on existing customers in a way that adversely impacts the economics of existing energy contracts, as in Nevada, we could further see an increase in the default rate of existing energy contracts or we may find it necessary to renegotiate our pricing of affected customers.

Limits on net metering, interconnection of solar energy systems and other operational policies in key markets could limit the number of solar energy systems installed in those markets. For example, California investor-owned utilities are currently required to provide net metering to their customers until the total generating capacity of net metered systems exceeds 5% of the utilities' "aggregate customer peak demand." In January 2016, the California Public Utilities Commission established a new net metering program requiring that customers utilize a time-of-use tariff, with no participation cap that will apply after the current 5% cap is reached. New York is considering a net metering successor program through the Reforming the Energy Vision docket at the state Public Service Commission. If the caps on net metering in New York and other key markets are reached or if the amount or value of credit that customers receive for net metering is significantly reduced or eliminated, future customers will be unable to recognize the current cost savings associated with net metering and existing customers may not recognize the economic benefits that were available at the time their energy contracts were entered into. We rely substantially on net metering when we establish competitive pricing for our prospective customers and the absence of net metering for new customers could greatly limit demand for our solar energy systems and increase the default rate of existing energy contracts.

Regulatory limitations associated with technical considerations may significantly limit our ability to sell electricity from our solar energy systems in certain markets.

Regulatory limits associated with technical considerations may curb our growth in certain key markets. For example, the Federal Energy Regulatory Commission has promulgated small generator interconnection procedures that recommend limiting customer-sited intermittent generation resources, such as our solar energy systems, to a certain percentage of peak load on a given electrical feeder circuit. Similar limits have been adopted by various states and could constrain our ability to market to customers in certain geographic areas where the concentration of solar installations exceeds the limit. For example, Hawaiian electric utilities have adopted certain policies that limit distributed electricity generation in certain geographic areas. While these limits have constrained our growth in certain parts of Hawaii, policy developments in Hawaii generally have allowed distributed electricity generation penetration despite the electric utility-imposed limitations. Furthermore, in certain areas, we benefit from policies that allow for expedited or simplified procedures

related to connecting solar energy systems to the power grid. If such procedures are changed or cease to be available, our ability to sell the electricity generated by solar energy systems we install may be adversely impacted. As adoption of solar distributed generation increases, along with the operation of large-scale solar generation in key markets such as California, the amount of solar energy being fed into the power grid will surpass the amount planned for relative to the amount of aggregate demand. Some utilities claim that within several years, solar generation resources may reach a level capable of causing an over-generation situation that could require some solar generation resources to be curtailed to maintain operation of the grid. The adverse effects of such curtailment without compensation could adversely impact our business, results of operations and future growth.

Our business currently depends on the availability of rebates, tax credits and other financial incentives. The expiration, elimination or reduction of these rebates, credits and incentives would adversely impact our business.

U.S. federal, state and local government bodies provide incentives to end users, distributors, system integrators and manufacturers of solar energy systems to promote solar electricity in the form of rebates, tax credits and other financial incentives such as system performance payments, payments for renewable energy credits associated with renewable energy generation and the exclusion of solar energy systems from property tax assessments. We rely on these governmental rebates, tax credits and other financial incentives to lower our cost of capital and to encourage fund investors to invest in our funds. These incentives enable us to lower the price we charge customers for energy and for our solar energy systems. However, these incentives may expire on a particular date, end when the allocated funding is exhausted or be reduced or terminated as solar energy adoption rates increase. These reductions or terminations often occur without warning.

The federal government currently offers a 30% investment tax credit under Section 48(a)(3) and Section 25D of the IRC, or the Federal ITC, for the installation of certain solar power facilities until December 31, 2016. Additionally, under Section 48, energy storage systems that are installed at the time of the solar power facility and, as required by IRS guidelines, store the energy of the solar power facility, are also eligible for the Federal ITC.

The credit under Section 48(a)(3) has been modified to remain at 30% of qualified expenditures for a commercial solar energy system that commences construction by December 31, 2019, then decline to 26% for systems that commence construction by December 31, 2020 and to 22% for systems that commence construction by December 31, 2021. The credit is scheduled to decline to a permanent 10% effective January 1, 2022. Historically, we have utilized the Section 48 commercial credit when available for both our residential and commercial leases and power purchase agreements, based on ownership of the solar energy system.

The credit under Section 25D has been modified to remain 30% of qualified expenditures for a residential solar energy system owned by the homeowner that is placed in service by December 31 2019, then decline to 26% for systems placed in service by December 21, 2020, and to 22% for systems placed in service by December 31, 2021. The credit is scheduled to expire effective January 1, 2022. MyPower customers can currently claim the Section 25D investment tax credit. Customers who purchase their solar energy systems for cash are also eligible to claim the Section 25D investment tax credit.

Department of Treasury regulations detailing how the commence construction requirements can be satisfied are expected by the end of the first quarter of 2016. Applicable authorities may adjust or decrease incentives from time to time or include provisions for minimum domestic content requirements or other requirements to qualify for these incentives.

Reductions in, eliminations of, or expirations of, governmental incentives could adversely impact our results of operations and ability to compete in our industry by increasing our cost of capital, causing us to increase the prices of our energy and solar energy systems and reducing the size of our addressable market. In addition, this would adversely impact our ability to attract investment partners and to form new financing funds and our ability to offer attractive financing to prospective customers.

Our business depends in part on the regulatory treatment of third-party owned solar energy systems.

Our leases and power purchase agreements are third-party ownership arrangements. Sales of electricity by third parties face regulatory challenges in some states and jurisdictions. Other challenges pertain to whether third-party owned systems qualify for the same levels of rebates or other non-tax incentives available for customer-owned solar energy systems, whether third-party owned systems are eligible at all for these incentives and whether third-party owned systems are eligible for net metering and the associated significant cost savings. In some states and utility territories, third parties that own solar energy systems are limited in the way that they may deliver solar energy to their customers. In jurisdictions such as Arizona, Florida, Georgia, Iowa, Kentucky, North Carolina, Oklahoma and the Los Angeles Department of Water and Power service territory, laws have been interpreted to prohibit the sale of electricity pursuant to our standard power purchase agreement. This has led us and other solar energy system providers that utilize third-party ownership arrangements to offer leases rather than power purchase agreements in such jurisdictions. Imposition of such limitations in additional jurisdictions or reductions in, or eliminations of, incentives for third-party owned systems could reduce demand

for our systems, adversely impact our access to capital and cause us to increase the price we charge our customers for energy.

The Office of the Inspector General of the U.S. Department of Treasury has issued subpoenas to a number of significant participants in the solar energy installation industry, including us. The subpoena we received requires us to deliver certain documents in our possession relating to our participation in the U.S. Treasury grant program. These documents are being delivered to the Office of the Inspector General of the U.S. Department of Treasury, which is investigating the administration and implementation of the U.S. Treasury grant program.

In July 2012, we and other companies that are significant participants in both the solar industry and the cash grant program under Section 1603 of the American Recovery and Reinvestment Act of 2009 received subpoenas from the U.S. Department of Treasury's Office of the Inspector General to deliver certain documents in our respective possession. In particular, our subpoena requested, among other things, documents dated, created, revised or referred to since January 1, 2007 that relate to our applications for U.S. Treasury grants or communications with certain other solar companies or certain firms that appraise solar energy property for U.S. Treasury grant application purposes. The Inspector General is working with the Civil Division of the U.S. Department of Justice to investigate the administration and implementation of the U.S. Treasury grant program, including possible misrepresentations concerning the fair market value of the solar power systems submitted for grant under that program made in grant applications by solar companies, including us. We intend to cooperate fully with the Inspector General and the Department of Justice and continue to produce documents and testimony as requested by the Inspector General. We are unable to anticipate when the Inspector General will conclude its review. If, at the conclusion of the investigation, the Inspector General concludes that misrepresentations were made, the Department of Justice could bring a civil action to recover amounts it believes were improperly paid to us. If the Department of Justice were successful in asserting such an action, we could then be required to pay damages and penalties for any funds received based on such misrepresentations (which, in turn, could require us to make indemnity payments to certain of our fund investors). Such consequences could have a material adverse effect on our business, liquidity, financial condition and prospects. Additionally, the period of time necessary to resolve the investigation is uncertain and this matter could require significant management and financial resources that could otherwise be devoted to the operation of our business.

If the Internal Revenue Service or the U.S. Treasury Department makes additional determinations that the fair market value of our solar energy systems is materially lower than what we have claimed, we may have to pay significant amounts to our financing funds or to our fund investors and such determinations could have a material adverse effect on our business, financial condition and prospects.

We and our fund investors claim the Federal ITC or the U.S. Treasury grant in amounts based on the fair market value of our solar energy systems. We have obtained independent appraisals to support the fair market values we report for claiming Federal ITCs and U.S. Treasury grants. The Internal Revenue Service and the U.S. Treasury Department review these fair market values. With respect to U.S. Treasury grants, the U.S. Treasury Department reviews the reported fair market value in determining the amount initially awarded. The Internal Revenue Service and the U.S. Treasury Department may subsequently audit the fair market value and determine that amounts previously awarded must be repaid to the U.S. Treasury Department or that excess awards constitute taxable income for U.S. federal income tax purposes. A small number of our financing funds are undergoing such audits. With respect to Federal ITCs, the Internal Revenue Service may review the fair market value on audit and determine that the tax credits previously claimed must be reduced. If the fair market value is determined to be less than we reported, we may owe our financing fund or fund investors an amount equal to this difference, plus any costs and expenses associated with a challenge to that valuation. We could also be subject to tax liabilities, including interest and penalties.

The U.S. Treasury Department has previously determined to award U.S. Treasury grants for some of our solar energy systems at a materially lower value than we had established in our appraisals. As a result, we have been required to pay our fund investors a true-up payment or contribute additional assets to the associated financing funds. It is possible that the U.S. Treasury Department will make similar determinations in the future. In response to such shortfalls, two of our financing funds filed a lawsuit in the United States Court of Federal Claims to recover the difference between the U.S. Treasury grants they sought and the amounts the U.S. Treasury paid; to the extent that these lawsuits are successful, any recovery would be used to repay us for amounts we previously reimbursed those funds. Our fund investors have contributed to our financing funds at the amounts the U.S. Treasury Department most recently awarded on similarly situated energy systems in order to reduce or eliminate the need for us to subsequently pay those fund investors true-up payments or contribute additional assets to the associated financing funds.

The Internal Revenue Service or the U.S. Treasury Department may object to the fair market value of solar energy systems that we have constructed, or will construct, including any systems for which grants have already been paid, as a result of:

- any pending or future audit,
- the outcome of the Department of Treasury Inspector General investigation, or
- changes in guidelines or otherwise.

If the Internal Revenue Service or the U.S. Treasury Department were to object to amounts we have claimed as too high of a fair market value on such systems, it could have a material adverse effect on our business, financial condition and prospects. For example, a hypothetical 5% downward adjustment in the fair market value of the $501.2 million of U.S. Department of Treasury grant applications that have been awarded from the beginning of the U.S. Treasury grant program through December 31, 2015 would obligate us to repay up to $25.1 million to our fund investors.

We need to enter into additional substantial financing arrangements to facilitate our customers' access to our solar energy systems, and if this financing is not available to us on acceptable terms, if and when needed, our ability to grow our business would be materially adversely impacted.

Our future success depends on our ability to raise capital from third-party fund investors to help finance the deployment of our residential and commercial solar energy systems. In particular, our strategy is to reduce the cost of capital through these arrangements to improve our margins, offset future reductions in government incentives and maintain the price competitiveness of our solar energy systems. If we are unable to establish new financing funds when needed, or on desirable terms, to enable our customers' access to our solar energy systems with little or no upfront cost, we may be unable to finance installation of our customers' systems, or our cost of capital could increase, either of which would have a material adverse effect on our business, financial condition and results of operations. If we are unable to establish new financing funds when needed or at all, or on desirable terms, to enable our customers' access to our solar energy systems with little or no upfront cost, we may encounter difficulty financing installation of our customers' systems, or our cost of capital could increase, either of which would have a material adverse effect on our business, financial condition and results of operations. To date, we have raised capital sufficient to finance installation of our customers' solar energy systems from a number of financial institutions and other large companies. Our ability to draw on financing commitments is subject to the conditions of the agreements underlying our financing funds. If we do not satisfy such conditions due to events related to our business or a specific financing fund, developments in our industry (including related to the Department of Treasury Inspector General investigation) or otherwise, and as a result we are unable to draw on existing commitments, it could have a material adverse effect on our business, liquidity, financial condition and prospects. If any of the financial institutions or large companies that currently invest in our financing funds decide not to invest in future financing funds to finance our solar energy systems due to general market conditions, concerns about our business or prospects, the pendency of the Department of Treasury Inspector General investigation or any other reason, or materially change the terms under which they are willing to provide future financing, we will need to identify new financial institutions and companies to invest in our financing funds and negotiate new financing terms.

In the past, challenges raising new funds have caused us to delay deployment of a substantial number of solar energy systems for which we had already signed leases or power purchase agreements with customers. For example, in late 2008 and early 2009, as a result of the state of the capital markets, our ability to finance the installation of solar energy systems was limited and resulted in a significant backlog of signed sales orders for solar energy systems. Our future ability to obtain additional financing depends on the continued confidence of banks and other financing sources in our business model and the solar energy industry as a whole. It could also be impacted by the liquidity needs of such financing sources. In addition, attracting future financing could be more difficult or costly to secure if the quality of our customer contracts, as perceived by our fund investors, were to decrease as a result of an increase in customer default rates, lower credit rating requirements for new customers or other factors. Solar energy has yet to achieve broad market acceptance and depends on continued support in the form of performance-based incentives, rebates, tax credits and other incentives from federal, state, local and foreign governments. If this support diminishes, our ability to obtain external financing, on acceptable terms or otherwise could be materially adversely affected. In addition, we face competition for these third-party investor funds. If we are unable to continue to offer a competitive investment profile, we may lose access to these funds or they may only be available on less favorable terms than are available to our competitors. Our current financing sources may be inadequate to support the anticipated growth in our business plans. Moreover, we will require additional capital in the near term, and we continue to look for opportunities to optimize our capital structure. We plan to pursue sources of such capital through various financing transactions and arrangements. Our inability to secure financing could lead to cancellations and could impair our ability to accept new projects and customers. In addition, our borrowing costs could increase, which would have a material adverse effect on our business, financial condition and results of operations.

We have historically benefited from the declining cost of solar panels, and our business and financial results may be harmed as a result of increases in the cost of solar panels or tariffs on imported solar panels imposed by the U.S. government.

The declining cost of solar panels and the raw materials necessary to manufacture them has been a key driver in the pricing of our solar energy systems and customer adoption of this form of renewable energy. With an increase of solar panel and raw materials prices, our growth could slow, and our financial results could suffer. Further, the cost of solar panels and raw materials could potentially increase in the future due to a variety of factors which we cannot control, including the imposition of duties, subsidies and/or safeguards or other trade-related costs or penalties or shortages of essential components.

The U.S. government imposes antidumping and countervailing duties on solar cells manufactured in China and/or Taiwan. Based on determinations by the U.S. government, the antidumping and countervailing duty rates range from approximately 33%-255%. Such antidumping and countervailing duties are subject to annual review and may be increased or decreased.

In addition, the U.S. government imposed additional tariffs on solar modules manufactured in China (with solar cells manufactured in other countries) and solar cells manufactured in Taiwan. In early January 2015, the U.S. government announced its affirmative final determinations in both the countervailing duty and antidumping cases against China and in the antidumping case against Taiwan.

Since these tariffs are reflected in the purchase price of the solar panels and cells, these tariffs are a cost associated with purchasing these solar products. In the past, we purchased a significant number of the solar panels used in our solar energy systems from manufacturers that were based in China. We continue to be affected by these tariffs/duties and any changes to them as many of the solar panels we currently purchase contain components, including solar cells, from China and Taiwan.

If additional tariffs are imposed or other negotiated outcomes occur, our ability to purchase these products on competitive terms or to access specialized technologies from countries like China and Taiwan could be limited. Further, foreign suppliers in other countries could also be the subject of these or future trade cases. Any of these events could harm our financial results by requiring us to account for the cost of trade penalties or to purchase and integrate solar panels or other system components from alternative and potentially higher-priced sources.

In September 2014, we acquired Silevo, a solar panel technology and manufacturing company. In May 2015, we were contacted by the U.S. Customs and Border Protection, or CBP, to provide information regarding our importation of solar panels manufactured by Silevo in China. In response to CBP's request for information, we provided applicable documentation to CBP and engaged in a review with their staff. Following this review, we reached an informal consensus with CBP that Silevo's solar panels are exempt from the scope of the antidumping and countervailing duties orders. In addition, we have submitted a request for a scope ruling with the U.S. Department of Commerce for a determination on this issue. We anticipate receiving a response from the Department of Commerce in March 2016, and we have ceased importing Silevo solar panels manufactured in China while we await their decision. We believe that the Silevo solar panels are exempt from these tariffs.

Our ability to provide solar energy systems to new customers on an economically viable basis depends on our ability to finance these systems with fund investors who require particular tax and other benefits.

Our solar energy systems have been eligible for Federal ITCs or U.S. Treasury grants, as well as depreciation benefits. We have relied on, and will continue to rely on, financing structures that monetize a substantial portion of those benefits and provide financing for our solar energy systems. With the lapse of the U.S. Treasury grant program, our reliance on these tax-advantaged financing structures has substantially increased. If, for any reason, we were unable to continue to monetize those benefits through these arrangements, we may be unable to provide and maintain solar energy systems for new customers on an economically viable basis.

The availability of this tax-advantaged financing depends upon many factors, including:

- our ability to compete with other renewable energy companies for the limited number of potential fund investors, each of which has limited funds and limited appetite for the tax benefits associated with these financings;
- the state of financial and credit markets;
- changes in the legal or tax risks associated with these financings;
- non-renewal of these incentives or decreases in the associated benefits; and
- no adverse changes in the regulatory environment affecting the economics of our existing energy contracts.

Under current law, the Federal ITC will be reduced from 30% of the cost of solar energy systems to 26% of the cost of solar energy systems for systems that commence construction by December 31, 2020, and then reduced again to 22% of the cost of solar energy systems for systems that commence construction by December 31, 2021, until the Section 25D

investment tax credit expires and the Section 48(a)(3) investment tax credit declines to a permanent 10% effective January 1, 2022.

In addition, U.S. Treasury grants are no longer available for new solar energy systems. Moreover, potential fund investors must remain satisfied that the structures we offer make the tax benefits associated with solar energy systems available to these investors, which depends both on the investors' assessment of the tax law and the absence of any unfavorable interpretations of that law. Changes in existing law and interpretations by the Internal Revenue Service and the courts could reduce the willingness of fund investors to invest in funds associated with these solar energy system investments. In addition, changes by state energy regulators impairing the economics of existing energy contracts causing an increased risk of default may also reduce the willingness of fund investors to invest. We cannot assure you that this type of financing will be available to us. If, for any reason, we are unable to finance solar energy systems through tax-advantaged structures or if we are unable to realize or monetize depreciation benefits, we may no longer be able to provide solar energy systems to new customers on an economically viable basis. This would have a material adverse effect on our business, financial condition and results of operations.

A material drop in the retail price of utility-generated electricity or electricity from other sources would harm our business, financial condition and results of operations.

We believe that a customer's decision to buy renewable energy from us is primarily driven by their desire to pay less for electricity. The customer's decision may also be affected by the cost of other renewable energy sources. Decreases in the retail prices of electricity from the utilities or other renewable energy sources would harm our ability to offer competitive pricing and could harm our business. The price of electricity from utilities could decrease as a result of:

- the construction of a significant number of new power generation plants, including nuclear, coal, natural gas or renewable energy technologies;
- the construction of additional electric transmission and distribution lines;
- a reduction in the price of natural gas, including as a result of new drilling techniques or a relaxation of associated regulatory standards;
- the development of energy conservation technologies and public initiatives to reduce electricity consumption; and
- the development of new renewable energy technologies that provide less expensive energy.

A reduction in utility electricity prices would make the purchase of our solar energy systems or the purchase of energy under our lease and power purchase agreements less economically attractive. In addition, a shift in the timing of peak rates for utility-generated electricity to a time of day when solar energy generation is less efficient could make our solar energy system offerings less competitive and reduce demand for our products and services. If the retail price of energy available from utilities were to decrease for any reason, we would be at a competitive disadvantage. As a result of these or similar events impacting the economics of our customer agreements, we may be unable to attract new customers and we may experience an increased rate of defaults under our existing customer agreements.

A material drop in the retail price of utility-generated electricity would particularly adversely impact our ability to attract commercial customers.

Commercial customers comprise a significant and growing portion of our business, and the commercial market for energy is particularly sensitive to price changes. Typically, commercial customers pay less for energy from utilities than residential customers. Because the price we are able to charge commercial customers is only slightly lower than their current retail rate, any decline in the retail rate of energy for commercial entities could have a significant impact on our ability to attract commercial customers. We may be unable to offer solar energy systems in commercial markets that produce electricity at rates that are competitive with the unsubsidized price of retail electricity. If this were to occur, our business would be harmed because we would be at a competitive disadvantage compared to other energy providers and may be unable to attract new commercial customers.

The terms of our agreement with the Research Foundation for the State University of New York, as amended, pertaining to the construction of the Buffalo Riverbend Manufacturing Facility, among other things, require us to comply with a number of covenants during the term of the agreement. Any failure to comply with these covenants could obligate us to pay significant amounts to the Foundation and result in termination of the agreement.

In September 2014, Silevo entered into an amended and restated research and development alliance agreement, as amended from time to time, referred to as the Riverbend Agreement, with the Research Foundation for the State University of New York, referred to as the Foundation, for the construction of an approximately 1 million square foot manufacturing facility capable of producing 1-gigawatt of solar panels annually on an approximately 88.24 acre site located in Buffalo, New York, referred to as the Manufacturing Facility.

Under the terms of the Riverbend Agreement, the Foundation will construct the Manufacturing Facility and install certain utilities and other improvements, with participation by us as to the design and construction of the Manufacturing Facility, and acquire certain manufacturing equipment designated by us to be used in the Manufacturing Facility and other specified items. The Foundation will cover construction costs related to the Manufacturing Facility and certain manufacturing equipment, in each case up to a maximum funding allocation from the State of New York, as well as additional specified items, and we will be responsible for any construction and equipment costs in excess of such amounts. The Foundation will own the Manufacturing Facility and manufacturing equipment it acquires for the project. We are also responsible for the acquisition of certain manufacturing equipment, which equipment we will own. Following completion of the Manufacturing Facility, we will lease the Manufacturing Facility from the Foundation for an initial period of 10 years for $2 per year plus utilities, and the Foundation will grant us the right to use the manufacturing equipment owned by it during the initial lease term at no charge.

In addition to the other obligations under the Riverbend Agreement, we must (i) use our best commercially reasonable efforts to commission the manufacturing equipment within three months of Manufacturing Facility completion and reach full production output within three months thereafter, (ii) employ personnel for at least 1,460 jobs in Buffalo, New York, with 500 of such jobs for the manufacturing operation at the Manufacturing Facility, for the initial two years of collaboration commencing after Manufacturing Facility completion, and we have committed to the retention of these jobs for five years, (iii) employ at least 2,000 other personnel in the State of New York for five years after Manufacturing Facility completion, (iv) employ a total of 5,000 people in the State of New York by the tenth anniversary of Manufacturing Facility completion, (v) spend or incur approximately $5 billion in combined capital, operational expenses and other costs in the State of New York during the 10 year period following full production, (vi) make reasonable efforts to provide first consideration to New York-based suppliers, (vii) invest and spend in manufacturing operations at a level that ensures competitive product costs for at least five years from full production, and (viii) negotiate in good faith with the Foundation on an exclusive "first opportunity basis" for 120 days before entering into any agreement for additional solar panel manufacturing capacity that Silevo may wish to develop during the term of the agreement. If we are not able to hire the specified number of employees or identify and qualify local vendors and suppliers, we would face the risk of not only failing to meet the performance criteria under the Riverbend Agreement but also not being capable of running the operations related to the Manufacturing Facility. If we fail in any year over the course of the ten-year term to meet these specified investment and job creation obligations, as described above, we would be obligated to pay a "program payment" of $41.2 million to the Foundation in any such year. In addition, we are subject to other events of defaults, including breach of these program payments and certain insolvency events, that would lead to the acceleration of all of the then unpaid program payments by us to the Foundation. Our failure to meet our contractual obligations under the Riverbend Agreement may result in our obligation to pay significant amounts to the Foundation in scheduled program payments, other contractual damages and/or the termination of our lease of the Manufacturing Facility. Any inability on our part to raise the capital necessary to operate the Manufacturing Facility and meet the specified requirements of the Riverbend Agreement during the 10-year period following full production would also cause a material adverse effect upon our business operations and prospects.

Our expectations as to the cost of building the Manufacturing Facility, acquiring manufacturing equipment and supporting our manufacturing operations may prove incorrect, which could subject us to significant expenses to achieve the desired benefits under the Riverbend Agreement. In the event of any cost overruns in construction, commissioning, acquiring manufacturing equipment or operating the Manufacturing Facility, we may incur additional capital and operating expenses that would have a material adverse effect upon our business operations and prospects.

Our projections as to the time and expense necessary to build the Manufacturing Facility and acquire the manufacturing equipment may prove incorrect and subject us to significant delay and additional expense.

We currently anticipate that construction of the Manufacturing Facility will be completed in March or April of 2016, after which time we will commence installation and commissioning of the manufacturing equipment. To date, we have experienced delays in purchasing some of the manufacturing equipment, due in part to longer lead times than we originally expected. While we currently believe that all manufacturing equipment will be delivered by the second quarter of 2017, we may experience additional unforeseen delays. Based on our current forecast, we estimate that we will commence manufacturing solar modules at the Manufacturing Facility in the third quarter of 2017. However, this is an aggressive schedule and we may experience additional delays.

There are a number of risks which may delay the completion of the Manufacturing Facility and commencement of operations, including:

- delays in placing orders for necessary equipment with long lead times;
- failure or delay in obtaining necessary permits, licenses or other governmental support or approvals;
- the time necessary for the construction of related utility and infrastructure improvements;

- unforeseen engineering problems;
- the inability to identify and hire qualified construction and other workers on a timely basis or at all;
- construction delays and contractor performance shortfalls;
- work stoppages or labor disruptions, including efforts by our employees to enter into collective bargaining agreements;
- availability of raw materials and components from suppliers and any delivery delays in such materials or components;
- delays resulting from environmental conditions, and any design changes or additions necessary to remediate prior environmental hazards at the site; and
- adverse weather conditions, such as an extreme winter, and natural disasters.

Any delay in the completion of the Manufacturing Facility and commencement of our operations will result in us incurring additional expenses and could negatively affect our operating results, financial condition and prospects.

We may not be able to achieve anticipated production yields, efficiencies and quality, which would harm our production volume and increase our costs.

The Manufacturing Facility is expected to be the largest of its kind in the Western Hemisphere. Successfully achieving volume manufacturing of solar cells at our projected yield, efficiency and quality levels will be difficult, and we have little experience in manufacturing at these high volumes. As we expand our manufacturing capacity and qualify additional suppliers to support our projected production volume, we may initially experience lower yields than anticipated. Any deviations in our manufacturing processes may result in significant decreases in production yield, efficiency and quality, and in some cases, may cause production to be suspended or yield no output. If we cannot achieve planned yields over time, our production costs could increase and we may be unable to produce a sufficient amount of our solar panels to meet our installation needs.

In addition, Silevo's Triex technology is novel and involves proprietary and complex manufacturing techniques, which may result in undetected errors or defects in the solar cells produced. Any defects in our solar panels could cause us to incur significant warranty, non-warranty and re-engineering costs, divert the attention of our engineering personnel, result in indemnification liability to our fund investors and significantly affect our customer relations and business reputation.

If we are unable to achieve our cost projections or otherwise control the costs associated with operating our manufacturing business, our financial condition and operating results will suffer.

As a result of initial production levels that under-utilize the Manufacturing Facility as we ramp up production, we anticipate that our initial production costs (on a per watt basis) will be relatively high. As we work to achieve full utilization of the Manufacturing Facility, we anticipate that the volume of production will reduce our production costs (on a per watt basis). There is no guarantee that we will be able to achieve planned cost targets, some of which will be beyond our control. For example, the costs of our raw materials and components, such as polysilicon and polysilicon wafers, could increase due to shortages as global demand for these products increases. Any failure to achieve our per watt cost projections would cause our financial condition and operating results to suffer. In addition, the pricing of our solar energy systems may become less competitive if our competitors are able to reduce their manufacturing and installation costs faster than we are able to.

Competition in the solar industry is intense, and future success and innovation will require additional research and development expenses.

The Manufacturing Facility is designed to be a high-technology volume-manufacturing facility. In constructing the Manufacturing Facility, including local utility infrastructure upgrades and procurement of manufacturing equipment, the State of New York is making a significant investment in the Buffalo-area economy. However, the solar panel manufacturing market is characterized by continually changing technology that requires improved features, such as increased efficiency, higher power output and enhanced aesthetics. In the time it takes us to achieve volume production of Silevo's Triex technology, it is possible that additional innovations in solar technology could result in our technology and

the Manufacturing Facility becoming less competitive or obsolete, which could harm our costs and adversely affect our business operations. This risk requires us to continuously focus on research and development, and will require significant on-going research and development expenses. If we cannot continually improve the efficiency and power output of our solar panels and reduce the cost of production, we could become less competitive in the market and our financial condition and operating results could be adversely affected.

Rising interest rates could adversely impact our business.

Changes in interest rates could have an adverse impact on our business by increasing our cost of capital. For example:

- rising interest rates would increase our cost of capital; and
- rising interest rates may negatively impact our ability to secure financing on favorable terms to facilitate our customers' purchase of our solar energy systems or energy generated by our solar energy systems.

The majority of our cash flows to date have been from solar energy systems under lease and power purchase agreements that have been monetized under various financing fund structures. One of the components of this monetization is the present value of the payment streams from our customers who enter into these leases and power purchase agreements. If the rate of return required by the fund investor rises as a result of a rise in interest rates, it will reduce the present value of the customer payment stream and consequently reduce the total value that we are able to derive from monetizing the payment stream. Interest rates are at historically low levels, partially as a result of intervention by the U.S. Federal Reserve. The U.S. Federal Reserve has taken actions to taper its intervention, and should these actions continue, it is likely that interest rates will rise, which could cause our cost of capital to increase and impede our ability to secure financing. As a result, our business and financial condition could be harmed.

In addition, we evaluate our business with a long-term view based on cash flows relating to our customer agreements, third-party financing funds and other arrangements. To date, we have taken limited actions to mitigate the risk of rising future interest rates. In 2014, we initiated a strategy of purchasing limited long-term derivative securities to economically hedge the effect of future interest rate increases. We may continue to engage in such transactions and the cost and outcomes of such transactions are currently not known.

We are expanding our international activities and customers, and plan to continue these efforts, which subject us to additional business risks, including compliance with international and trade regulations.

Our long-term strategic plans include international expansion and we intend to sell our solar energy products and services in international markets. For example, in August 2015, we acquired Ilioss to expand our operations into Mexico.

Risks inherent to our international operations include the following:

- multiple, conflicting and changing laws and regulations, including energy regulations, export and import restrictions, tax laws and regulations, environmental regulations, labor laws and other government requirements, approvals, permits and licenses;
- trade barriers and trade remedies such as export requirements, tariffs, taxes and other restrictions and expenses, which could increase the prices of our products and make us less competitive in some countries;
- potentially adverse tax consequences associated with our permanent establishment of operations in more countries, including repatriation of non-U.S. earnings taxed at rates lower than the U.S. statutory effective tax rate;
- difficulties and costs in recruiting and retaining individuals skilled in international business operations;
- changes in general economic and political conditions in the countries where we operate, including changes in government incentives relating to power generation and solar electricity, and availability of capital at competitive rates;
- political and economic instability, including wars, acts of terrorism, political unrest, boycotts, curtailments of trade and other business restrictions;
- the inability to work successfully with third parties with local expertise to co-develop international projects;
- relatively uncertain legal systems, including potentially limited protection for intellectual property rights and laws, changes in the governmental incentives we rely on, regulations and policies which impose additional restrictions on the ability of foreign companies to conduct business in certain countries or otherwise place them at a competitive disadvantage in relation to domestic companies;

- international business practices that may conflict with CBP or other legal requirements enforced by partner government agencies;
- financial risks, such as longer sales and payment cycles and greater difficulty collecting accounts receivable; and
- fluctuations in currency exchange rates relative to the U.S. dollar.

Doing business in foreign markets requires us to be able to respond to rapid changes in market, legal, and political conditions in these countries. The success of our business will depend in part on our ability to succeed in differing legal, regulatory, economic, social and political environments. We recognize that we must understand the risks and opportunities relating to trade remedies so that we can develop and implement policies and strategies that will be effective in each location where we do business.

We are subject to the FCPA, the U.S. domestic bribery statute contained in 18 U.S.C. § 201, the U.S. Travel Act, the USA PATRIOT Act, and other anti-bribery and anti-money laundering laws in countries in which we conduct activities. We face significant risks if we fail to comply with the FCPA and other anticorruption laws that prohibit companies and their employees and third-party intermediaries from authorizing, offering, or providing, directly or indirectly, improper payments or benefits to foreign government officials, political parties, and private-sector recipients for the purpose of obtaining or retaining business. In many foreign countries, particularly in countries with developing economies, it may be a local custom that businesses engage in practices that are prohibited by the FCPA or other applicable laws and regulations. We may have direct or indirect interactions with officials and employees of government agencies or state-owned or affiliated entities. We can be held liable for the corrupt or other illegal activities of our employees, representatives, contractors, partners, and agents, even if we do not explicitly authorize such activities. Any violation of the FCPA, other applicable anticorruption laws, and anti-money laundering laws could result in whistleblower complaints, adverse media coverage, investigations, loss of export privileges, severe criminal or civil sanctions and, in the case of the FCPA, suspension or debarment from U.S. government contracting, which could have a material adverse effect on our business, financial condition, cash flows and reputation. In addition, responding to any enforcement action may result in a materially significant diversion of management's attention and resources and significant defense costs and other professional fees.

Our vertically integrated and our continued international expansion efforts may subject us to additional regulatory risks that may impact our operating results. For example, we will have to ensure we are in compliance with any bilateral and/or multilateral free trade agreements in addition to understanding trade remedies that directly affect those products and components involved in the construction of our solar energy systems, which are procured from vendors and manufacturers outside of the United States. Some of these components, particularly solar panels and mounting hardware made from aluminum extrusions, may be subject to antidumping and countervailing duties.

While conducting an internal review of our supply chain and import practices, we recently identified certain potential instances in which our Zep Solar subsidiaries have imported system components and other products into the United States which were misclassified upon import. In addition, we discovered that certain parts may be subject to antidumping and countervailing duties. In September 2015, we submitted a voluntary disclosure to the CBP of these and other potential misclassifications, and we intend to cooperate with CBP as we finalize this review. As a result of these misclassifications, for the third quarter ended September 30, 2015, we recorded an accrual in the amount of approximately $5.3 million for import duties that we currently anticipate will be owed by our acquired subsidiaries to CBP relating to items imported since January 1, 2014. We are continuing to review information related to imports from prior periods and anticipate that amounts of import duties for these periods will not be significant. If our revised classifications or estimates prove to be incorrect with respect to these import duties, the actual amounts owed may materially increase as we finalize our disclosure with CBP, which we anticipate will occur during the first quarter of 2016. In addition, during the pendency of this review, we may be required to make full antidumping and countervailing duties deposits for imports determined to be inside the scope of the antidumping and countervailing duties orders. Any increase in the anticipated costs of import duties would increase our operating costs, which could be harmful to our financial results.

In the event that we fail to or are unable to comply with the legal requirements in the jurisdictions in which we operate, we may be subject to significant fines, penalties and other amounts which could materially harm our operations and financial results.

We may not realize the anticipated benefits of past or future acquisitions, and integration of these acquisitions may disrupt our business and management and cause dilution to our stockholders.

In August 2015, we acquired Iliosson S.A. de C.V., a commercial and industrial solar project developer in Mexico. In September 2014, we acquired Silevo, LLC, a solar panel technology and manufacturing company. In 2013, we acquired Zep Solar, Common Assets, certain assets of Paramount Solar and completed other smaller acquisitions. In the future, we may acquire additional companies, project pipelines, products or technologies, including additional

photovoltaics companies, or enter into joint ventures or other strategic initiatives. Our ability as an organization to integrate acquisitions is unproven. We may not realize the anticipated benefits of our acquisitions or any other future acquisition or the acquisition may be viewed negatively by customers, financial markets or investors.

Any acquisition has numerous risks, including the following:

- difficulty in assimilating the operations and personnel of the acquired company;
- difficulty in effectively integrating the acquired technologies or products with our current products and technologies;
- difficulty in maintaining controls, procedures and policies during the transition and integration;
- disruption of our ongoing business and distraction of our management and employees from other opportunities and challenges due to integration issues;
- difficulty integrating the acquired company's accounting, management information and other administrative systems;
- inability to retain key technical and managerial personnel of the acquired business;
- inability to retain key customers, vendors, and other business partners of the acquired business;
- inability to achieve the financial and strategic goals for the acquired and combined businesses;
- incurring acquisition-related costs or amortization costs for acquired intangible assets that could impact our operating results;
- failure of due diligence processes to identify significant issues with product quality, legal and financial liabilities, among other things;
- inability to assert that internal controls over financial reporting are effective; and
- inability to obtain, or obtain in a timely manner, approvals from governmental authorities, which could delay or prevent such acquisitions.

In connection with our acquisitions of Silevo, Zep Solar and Paramount Solar, we issued approximately 8.8 million shares of our common stock. In connection with our acquisition of Silevo, we may issue additional common stock with an aggregate value of up to $150 million, subject to adjustments, upon the timely achievement of all earnout related milestones. Following the announcement of the production of our record-breaking rooftop solar panel, we amended the Silevo merger agreement to reflect new product specifications and manufacturing process and to extend the deadline for achieving certain manufacturing-related milestones. In addition, we typically offer additional equity compensation to continuing employees of these businesses. If we are unable to successfully integrate these businesses and technologies or are unable to otherwise achieve the anticipated benefits of these acquisitions, the related issuances of our securities may be highly dilutive to our existing stockholders.

Servicing our debt requires a significant amount of cash and we may not have sufficient cash flow from our business to pay our substantial debt; other actions we are forced to take to satisfy our obligations under our indebtedness may not be successful.

Our total consolidated indebtedness was $2,753.7 million as of December 31, 2015. Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not continue to generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. In addition, our 2.75% Convertible Senior Notes due 2018 issued in November 2013 (the "2018 Notes"), our 1.625% Convertible Senior Notes due 2019 issued in September and October 2014 (the "2019 Notes") and our Zero Coupon Convertible Senior Notes due 2020 issued in December 2015 (the "2020 Notes" and together with the 2018 Notes and the 2019, the "Notes"), are convertible into shares of common stock, and we may engage in similar issuances of convertible securities in the future to fund our operating and expansion plans. Our ability to issue additional securities and to refinance our existing indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations.

We expect to incur substantially more debt or take other actions which would intensify the risks discussed above.

We and our subsidiaries expect to incur substantial additional debt in the future, subject to the restrictions contained in our debt instruments, some of which may be secured debt. Incurring such additional debt could have the effect of diminishing our ability to make payments on existing indebtedness, including the Notes, when due and otherwise limiting our ability to respond to periods of increased liquidity pressure. Although our existing credit facilities restrict our ability to incur additional indebtedness, including secured indebtedness, but we may be able to obtain amendments and waivers of such restrictions or may not be subject to such restrictions under the terms of any subsequent indebtedness.

We may have trouble refinancing our credit facilities or obtaining new financing for our working capital, equipment financing and other needs in the future or complying with the terms of existing credit facilities. If credit facilities are not available to us on acceptable terms, if and when needed, or if we are unable to comply with their terms, our ability to continue to grow our business would be adversely impacted.

As of December 31, 2015, we had the ability to draw up to an additional $234.2 million under all of our credit facilities. Our secured revolving credit facility, our primary working capital facility, currently has a maximum size of $500 million (with $398.5 million currently committed from several lenders and an additional $101.5 million subject to further conditions) that matures in December 2017. The working capital facility requires us to comply with certain financial, reporting and other requirements. The timing of our commercial projects has on occasion adversely affected our ability to satisfy certain financial covenants under these or prior facilities. While our lenders have given us waivers of certain covenants we have not satisfied in the past, there is no assurance that the lenders will waive or forbear from exercising their remedies with respect to any future defaults that might occur. In addition, we have amended our secured revolving credit facility to engage in transactions such as the issuance of the 2020 Notes and issue Solar Bonds debt securities. While we believe that some of the financial and other covenants are generally more favorable to us following these changes, a breach of our covenants may still occur in the future.

Further, there is no assurance that we will be able to enter into new credit facilities on acceptable terms. If we are unable to satisfy financial covenants and other terms under existing or new facilities or obtain associated waivers or forbearance from our lenders or if we are unable to obtain refinancing or new financings for our working capital, equipment and other needs on acceptable terms if and when needed, our business would be adversely affected.

We may not have the ability to raise the funds necessary to repurchase the Notes, including upon a fundamental change, and one of our current credit facilities prohibits us from repurchasing the issued Notes upon a fundamental change.

Holders of the Notes will have the right to require us to repurchase their Notes upon the occurrence of a fundamental change at a repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest, if any. However, at such time that we may be required to repurchase the Notes, we may not have sufficient available cash or be able to obtain sufficient financing to allow for repurchase. In addition, one of our existing credit facilities prohibits us from repurchasing the Notes upon a fundamental change. We may enter into agreements in the future that similarly restrict our ability to repurchase the Notes and other securities. Our failure to repurchase the Notes when required would constitute a default which could also result in defaults under other agreements governing our existing or future indebtedness. If the repayment of the related indebtedness were to be accelerated after any applicable notice or grace periods, we may not have sufficient funds to repay the indebtedness and repurchase the Notes or make cash payments upon conversions thereof. Our ability to repurchase the Notes may also be limited by law or by regulatory authority.

We have incurred losses and may be unable to achieve or sustain profitability in the future.

We have incurred net losses in the past, and we had an accumulated deficit of $316.7 million as of December 31, 2015. We may incur net losses from operations as we increase our spending to finance the expansion of our operations, expand our installation, engineering, administrative, sales and marketing staffs, and implement internal systems and infrastructure to support our growth. We do not know whether our revenue will grow rapidly enough to absorb these costs, and our limited operating history makes it difficult to assess the extent of these expenses or their impact on our operating results. Our ability to achieve profitability depends on a number of factors, including:

- growing our customer base;
- finding investors willing to invest in our financing funds;
- maintaining and further lowering our cost of capital;
- reducing the cost of components for our solar energy systems; and
- reducing our operating costs by optimizing our design and installation processes and supply chain logistics.

Even if we do achieve profitability, we may be unable to sustain or increase our profitability in the future.

If we are unable to maintain effective internal controls over financial reporting and disclosure controls and procedures, or if material weaknesses are discovered in future periods, the accuracy and timeliness of our financial and operating reporting may be adversely affected, and confidence in our operations and disclosures may be lost.

In connection with the audit of our consolidated financial statements for the year ended December 31, 2013, we identified four material weaknesses in our internal control over financial reporting relating to (i) the costing of our solar system installations, (ii) accounting for and classification of redeemable noncontrolling interests, (iii) segregation of incompatible duties at our lease administrator and our controls over the data received from our administrator, and (iv) certain areas of our financial statement close process. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis. These material weaknesses resulted from separate control deficiencies, as well as our misinterpretation of certain accounting standards, and resulted in the restatement of our consolidated financial statements as of and for the years ended December 31, 2012, 2011, 2010 and 2009 and for certain interim periods in 2012 and 2013.

As a result of significant efforts by us and our Audit Committee, we have successfully remediated these material weaknesses and improved our internal control over financial reporting.

In connection with this annual report on Form 10-K, our management has performed an evaluation of our internal control over financial reporting as of December 31, 2015 pursuant to Section 404 of the Sarbanes-Oxley Act, and has concluded that our internal control over financial reporting and our disclosure controls and procedures were effective as of December 31, 2015.

If we are not able to maintain effective internal control over financial reporting and disclosure controls and procedures, or if additional material weaknesses are discovered in future periods, a risk that is significantly increased in light of the complexity of our business and investment funds, we may be unable to accurately and timely report our financial position, results of operations, cash flows or key operating metrics, which could result in additional late filings of our annual and quarterly reports under the Exchange Act, additional restatements of our consolidated financial statements or other corrective disclosures, a decline in our stock price, suspension or delisting of our common stock by The NASDAQ Stock Market, an inability to access the capital and commercial lending markets, defaults under our secured revolving credit facility and other agreements, or other material adverse effects on our business, reputation, results of operations, financial condition or liquidity.

Updates or changes to our IT systems affecting our customer billing and control environment may disrupt our operations.

As we continue to evaluate and implement upgrades and changes to our IT systems affecting our customer billing and control environment, some of which are significant, we may encounter unexpected challenges, outages and other issues. Upgrades involve replacing existing systems with successor systems, making changes to existing systems, or cost-effectively acquiring new systems with new functionality. We are aware of inherent risks associated with replacing these systems, including accurately capturing data and system disruptions, and believe we are taking appropriate action to mitigate the risks through testing, training, and staging implementation, as well as ensuring appropriate commercial contracts are in place with third-party vendors supplying or supporting our IT initiatives. However, there can be no assurances that we will successfully launch these systems as planned or that they will occur without disruptions to our operations. IT system disruptions, if not anticipated and appropriately mitigated, or failure to successfully implement new or upgraded systems, could have a material adverse effect on our results of operations, and our ability to timely and accurately report our financial and operating results.

We are not currently regulated as a utility under applicable law, but we may be subject to regulation as a utility in the future.

Federal law and most state laws do not currently regulate us as a utility. As a result, we are not subject to the various federal and state standards, restrictions and regulatory requirements applicable to U.S. utilities. In the United States, we obtain federal and state regulatory exemptions by establishing "Qualifying Facility" status with the Federal Energy Regulatory Commission for all of our qualifying solar energy projects. In Canada, we also are generally subject to the regulations of the relevant energy regulatory agencies applicable to all producers of electricity under the relevant feed-in

tariff regulations (including the feed-in tariff rates), however we are not currently subject to regulation as a utility. Our business strategy includes the continued development of larger solar energy systems in the future for our commercial and government customers, which has the potential to impact our regulatory position. Any local, state, federal or foreign regulations could place significant restrictions on our ability to operate our business and execute our business plan by prohibiting or otherwise restricting our sale of electricity. If we were subject to the same state, federal or foreign regulatory authorities as utilities in the United States or if new regulatory bodies were established to oversee our business in the United States or in foreign markets, then our operating costs would materially increase.

A failure to hire and retain a sufficient number of employees in key functions would constrain our growth and our ability to timely complete our customers' projects.

To support our growth, we need to hire, train, deploy, manage and retain a substantial number of skilled employees. In particular, we need to continue to expand and optimize our sales infrastructure to grow our customer base and our business, and we plan to expand our direct sales force. Identifying, recruiting and training qualified personnel requires significant time, expense and attention. It can take several months before a new salesperson is fully trained and productive. If we are unable to hire, develop and retain talented sales personnel or if new direct sales personnel are unable to achieve desired productivity levels in a reasonable period of time, we may not be able to realize the expected benefits of this investment or grow our business.

To complete current and future customer projects and to continue to grow our customer base, we need to hire a large number of installers in the relevant markets. Competition for qualified personnel in our industry is increasing, particularly for skilled installers and other personnel involved in the installation of solar energy systems. We also compete with the homebuilding and construction industries for skilled labor. As these industries seek to hire additional workers, our cost of labor may increase. The unionization of our labor force could also increase our labor costs. Shortages of skilled labor could significantly delay a project or otherwise increase our costs. Because our profit on a particular installation is based in part on assumptions as to the cost of such project, cost overruns, delays or other execution issues may cause us to not achieve our expected margins or cover our costs for that project. In addition, because we are headquartered in the San Francisco Bay Area, we compete for a limited pool of technical and engineering resources that requires us to pay wages that are competitive with relatively high regional standards for employees in these fields.

If we cannot meet our hiring, retention and efficiency goals, we may be unable to complete our customers' projects on time, in an acceptable manner or at all. Any significant failures in this regard would materially impair our growth, reputation, business and financial results. If we are required to pay higher compensation than we anticipate, these greater expenses may also adversely impact our financial results and the growth of our business.

In our lease pass-through financing funds, there is a one-time reset of the lease payments, and we may be obligated, in connection with the resetting of the lease payments at true up, to refund lease prepayments or to contribute additional assets to the extent the system sizes, costs and timing are not consistent with the initial lease payment model.

In our lease pass-through financing funds, the models used to calculate the lease prepayments will be updated for each fund at a fixed date occurring after placement in service of all solar energy systems in a given fund or on an agreed upon date (typically within the first year of the applicable lease term) to reflect certain specified conditions as they exist at such date, including the ultimate system size of the equipment that was leased, how much it cost and when it went into service. As a result of such a true up, the lease payments are resized and we may be obligated to refund the investor's lease prepayments or to contribute additional assets to the fund. Any significant refunds or capital contributions that we may be required to make could adversely affect our financial condition.

We have guaranteed a minimum return to be received by an investor in one of our financing funds and could be adversely affected if we are required to make any payments under this guarantee.

We have guaranteed payments to the investor in one of our financing funds to compensate for payments that the investor would be required to make to a certain third party as a result of the investor not achieving a specified minimum internal rate of return in this fund, assessed annually. Although the investor has achieved the specified minimum internal rate of return to date, the amounts of any potential future payments under this guarantee depend on the amounts and timing of future distributions to the investor from the fund and the tax benefits that accrue to the investor from the fund's activities. Because of uncertainties associated with estimating the timing and amounts of future distributions to the investor, we cannot determine the potential maximum future payments that we could have to make under this guarantee. We may agree to similar guarantees in the future if market conditions require it. Any significant payments that we may be required to make under our guarantees could adversely affect our financial condition.

It is difficult to evaluate our business and prospects due to our limited operating history.

Since our formation in 2006, we have focused our efforts primarily on the sales, financing, engineering, installation and monitoring of solar energy systems for residential, commercial and government customers. We launched our pilot commercial and residential energy storage products and services in late 2013, and revenue attributable to this line of business has not been material compared to revenue attributable to our solar energy systems. We may be unsuccessful in significantly broadening our customer base through installation of solar energy systems within our current markets or in new markets we may enter. Additionally, we cannot assure you that we will be successful in generating substantial revenue from our current energy-related products and services or from any additional products and services we may introduce in the future. Our limited operating history, combined with the rapidly evolving and competitive nature of our industry, may not provide an adequate basis for you to evaluate our operating and financing results and business prospects. In addition, we only have limited insight into emerging trends that may adversely impact our business, prospects and operating results. As a result, our limited operating history may impair our ability to accurately forecast our future performance.

We face competition from both traditional energy companies and renewable energy companies.

The solar energy and renewable energy industries are both highly competitive and continually evolving as participants strive to distinguish themselves within their markets and compete with large utilities. We believe that our primary competitors are the traditional utilities that supply energy to our potential customers. We compete with these utilities primarily based on price, predictability of price and the ease by which customers can switch to electricity generated by our solar energy systems. If we cannot offer compelling value to our customers based on these factors, then our business will not grow. Utilities generally have substantially greater financial, technical, operational and other resources than we do. As a result of their greater size, these competitors may be able to devote more resources to the research, development, promotion and sale of their products or respond more quickly to evolving industry standards and changes in market conditions than we can. Utilities could also offer other value-added products and services that could help them compete with us even if the cost of electricity they offer is higher than ours. In addition, a majority of utilities' sources of electricity is non-solar, which may allow utilities to sell electricity more cheaply than electricity generated by our solar energy systems.

We also compete with solar companies in the downstream value chain of solar energy. For example, we face competition from purely finance driven organizations which then subcontract out the installation of solar energy systems, from installation businesses that seek financing from external parties, from large construction companies and utilities and increasingly from sophisticated electrical and roofing companies. Some of these competitors specialize in either the residential or commercial solar energy markets, and some may provide energy at lower costs than we do. Many of our competitors also have significant brand name recognition and have extensive knowledge of our target markets. Competitors have increasingly begun vertically integrating their operations to offer comprehensive products and services offerings similar to ours, and, recently, we have seen increased consolidation of competitors in our primary markets. For us to remain competitive, we must distinguish ourselves from our competitors by offering an integrated approach that successfully competes with each level of products and services offered by our competitors at various points in the value chain. As consolidation in our markets increases and more of our competitors develop an integrated approach similar to ours, our marketplace differentiation may suffer.

We also face competition in the energy-related products and services markets and we expect to face competition in additional markets as we introduce new products and services. As the solar industry grows and evolves, we will also face new competitors who are not currently in the market. Our failure to adapt to changing market conditions and to compete successfully with existing and new competitors could limit our growth and could have a material adverse effect on our business and prospects.

Projects for our significant commercial and government customers involve concentrated project risks that may cause significant changes in our financial results.

During any given financial reporting period, we typically have ongoing significant projects for commercial and governmental customers that represent a significant portion of our potential financial results for such period. For example, Walmart is a significant customer for which we have installed a substantial number of solar energy systems. These larger projects create concentrated operating and financial risks. The effect of recognizing revenue or other financial measures on

the sale of a larger project, or the failure to recognize revenue or other financial measures as anticipated in a given reporting period because a project is not yet completed under applicable accounting rules by period end, may materially impact our quarterly or annual financial results. In addition, if construction, warranty or operational issues arise on a larger project, or if the timing of such projects unexpectedly shifts for other reasons, such issues could have a material impact on our financial results. If we are unable to successfully manage these significant projects in multiple markets, including our related internal processes and external construction management, or if we are unable to continue to attract such significant customers and projects in the future, our financial results could be harmed.

We depend on a limited number of suppliers of solar panels and other system components to adequately meet anticipated demand for our solar energy systems. Any shortage, delay or component price change from these suppliers could result in sales and installation delays, cancellations and loss of our ability to effectively compete.

We purchase solar panels, inverters and other system components from a limited number of suppliers, which makes us susceptible to quality issues, shortages and price changes. If we fail to develop, maintain and expand our relationships with existing or new suppliers, we may be unable to adequately meet anticipated demand for our solar energy systems or we may only be able to offer our systems at higher costs or after delays. If one or more of the suppliers that we rely upon to meet anticipated demand ceases or reduces production, we may be unable to satisfy this demand due to an inability to quickly identify alternate suppliers or to qualify alternative products on commercially reasonable terms. In particular, there are a limited number of inverter suppliers. Once we design a system for use with a particular inverter, if that type of inverter is not readily available at an anticipated price, we may incur additional delay and expense to redesign the system.

In addition, production of solar panels involves the use of numerous raw materials and components. Several of these have experienced periods of limited availability, particularly polysilicon, as well as indium, cadmium telluride, aluminum and copper. The manufacturing infrastructure for some of these raw materials and components has a long lead time, requires significant capital investment and relies on the continued availability of key commodity materials, potentially resulting in an inability to meet demand for these components. The prices for these raw materials and components fluctuate depending on global market conditions and demand and we may experience rapid increases in costs or sustained periods of limited supplies.

In addition to purchasing from New York-based suppliers, we anticipate that we will need to purchase supplies globally in order to meet the anticipated production output of the Manufacturing Facility. Despite our efforts to obtain raw materials and components from multiple sources whenever possible, many of our suppliers may be single-source suppliers of certain components. If we are not able to maintain long-term supply agreements or identify and qualify multiple sources for raw materials and components, our access to supplies at satisfactory prices, volumes and quality levels may be harmed. We may also experience delivery delays of raw materials and components from suppliers in various global locations. In addition, we may be unable to establish alternate supply relationships or obtain or engineer replacement components in the short term, or at all, at favorable prices or costs. Qualifying alternate suppliers or developing our own replacements for certain components may be time-consuming and costly and may force us to make modifications to our product designs.

Our need to purchase supplies globally in order to meet the anticipated production output of the Manufacturing Facility and our continued international expansion further subjects us to risks relating to currency fluctuations. Any decline in the exchange rate of the U.S. dollar compared to the functional currency of our component suppliers could increase our component prices. In addition, the state of the financial markets could limit our suppliers' ability to raise capital if they are required to expand their production to meet our needs or satisfy their operating capital requirements. Changes in economic and business conditions, wars, governmental changes and other factors beyond our control or which we do not presently anticipate, could also affect our suppliers' solvency and ability to deliver components to us on a timely basis. Any of these shortages, delays or price changes could limit our growth, cause cancellations or adversely affect our profitability and ability to effectively complete in the markets in which we operate.

Our operating results may fluctuate from quarter to quarter, which could make our future performance difficult to predict and could cause our operating results for a particular period to fall below expectations, resulting in a severe decline in the price of our common stock.

Our quarterly operating results are difficult to predict and may fluctuate significantly in the future. We have experienced seasonal and quarterly fluctuations in the past. However, given that we are an early-stage public company operating in a rapidly growing industry, those fluctuations may be masked by our recent growth rates and thus may not be readily apparent from our historical operating results. As such, our past quarterly operating results may not be good indicators of future performance.

In addition to the other risks described in this "Risk Factors" section, the following factors could cause our operating results to fluctuate:

- expiration or initiation of any rebates or incentives;
- significant fluctuations in customer demand for our products and services;

- our ability to complete installations in a timely manner due to market conditions resulting in inconsistently available financing;
- our ability to continue to expand our operations, and the amount and timing of expenditures related to this expansion;
- actual or anticipated changes in our growth rate relative to our competitors;

- announcements by us or our competitors of significant acquisitions, strategic partnerships, joint ventures or capital-raising activities or commitments;
- changes in our pricing policies or terms or changes in those of our competitors, including utilities; and
- actual or anticipated developments in our competitors' businesses or the competitive landscape.

For these or other reasons, the results of any prior quarterly or annual periods should not be relied upon as indications of our future performance. In addition, our actual revenue, key operating metrics and other operating results in future quarters may fall short of the expectations of investors and financial analysts, which could have a severe adverse effect on the trading price of our common stock.

We act as the licensed general contractor for our customers and are subject to risks associated with construction, cost overruns, delays, regulatory compliance and other contingencies, any of which could have a material adverse effect on our business and results of operations.

We are a licensed contractor or use licensed subcontractors in every community we service, and we are responsible for every customer installation. For our residential projects, we are the general contractor, construction manager and installer. For our commercial projects, we are the general contractor and construction manager, and we have historically relied on licensed subcontractors to install these commercial systems. We may be liable to customers for any damage we cause to their home or facility and belongings or property during the installation of our systems. For example, we frequently penetrate our customers' roofs during the installation process and may incur liability for the failure to adequately weatherproof such penetrations following the completion of construction. In addition, shortages of skilled subcontractor labor for our commercial projects could significantly delay a project or otherwise increase our costs. Because our profit on a particular installation is based in part on assumptions as to the cost of such project, cost overruns, delays or other execution issues may cause us to not achieve our expected margins or not cover our costs for that project.

In addition, the installation of solar energy systems and energy-storage systems requiring building modifications are subject to oversight and regulation in accordance with national, state and local laws and ordinances relating to building codes, safety, utility interconnection and metering, environmental protection and related matters. It is difficult and costly to track the requirements of every individual authority having jurisdiction over our installations and to design solar energy systems to comply with these varying standards. Any new government regulations or utility policies pertaining to our systems may result in significant additional expenses to us and our customers and, as a result, could cause a significant reduction in demand for our systems.

Compliance with occupational safety and health requirements and best practices can be costly, and noncompliance with such requirements may result in potentially significant monetary penalties, operational delays and adverse publicity.

The installation of solar energy systems requires our employees to work at heights with complicated and potentially dangerous electrical systems. The evaluation and installation of our energy-related products requires our employees to work in locations that may contain potentially dangerous levels of asbestos, lead or mold. We also maintain a fleet of over 3,000 vehicles that our employees use in the course of their work. There is substantial risk of serious injury or death if proper safety procedures are not followed. Our operations are subject to regulation under the U.S. Occupational Safety and Health Act, or OSHA, and equivalent state laws. Changes to OSHA requirements, or stricter interpretation or enforcement of existing laws or regulations, could result in increased costs. If we fail to comply with applicable OSHA regulations, even if no work-related serious injury or death occurs, we may be subject to civil or criminal enforcement and be required to pay substantial penalties, incur significant capital expenditures or suspend or limit operations. In the past, we have had workplace accidents and received citations from OSHA regulators for alleged safety violations, resulting in fines and operational delays for certain projects. Any such accidents, citations, violations, injuries or failure to comply with industry best practices may subject us to adverse publicity, damage our reputation and competitive position and adversely affect our business.

Problems with product quality or performance may cause us to incur warranty expenses and performance guarantee expenses, may lower the residual value of our solar energy systems and may damage our market reputation and adversely affect our financial performance and valuation.

Our solar energy system warranties are lengthy. Customers who buy energy from us under leases or power purchase agreements are covered by warranties equal to the length of the term of these agreements—typically 20 years for leases and power purchase agreements and 30 years for MyPower loan agreements. Depending on the state where they live, customers who purchase our solar energy systems for cash are covered by a warranty up to 10 years in duration. We also make extended warranties available at an additional cost to customers who purchase our solar energy systems for cash. In addition, we provide a pass-through of the inverter and panel manufacturers' warranties to our customers, which generally range from 5 to 25 years. One of these third-party manufacturers could cease operations and no longer honor these warranties, leaving us to fulfill these potential obligations to our customers. For example, Evergreen Solar, Inc., one of our former solar panel suppliers, filed for bankruptcy in August 2011. Further, we provide a performance guarantee with our leased solar energy systems that compensates a customer on an annual basis if their system does not meet the electricity production guarantees set forth in their lease.

Because of the limited operating history of our solar energy systems, we have been required to make assumptions and apply judgments regarding a number of factors, including our anticipated rate of warranty claims and the durability, performance and reliability of our solar energy systems. We have made these assumptions based on the historic performance of similar systems or on accelerated life cycle testing. Our assumptions could prove to be materially different from the actual performance of our systems, causing us to incur substantial expense to repair or replace defective solar energy systems in the future or to compensate customers for systems that do not meet their production guarantees. Product failures or operational deficiencies would also reduce our revenue from power purchase agreements because they are dependent on system production. Any widespread product failures or operating deficiencies may damage our market reputation and adversely impact our financial results.

In addition, we amortize costs of our solar energy systems over 30 years, which typically exceeds the period of the component warranties and the corresponding payment streams from our operating lease arrangements with our customers. In addition, we typically bear the cost of removing the solar energy systems at the end of the lease term. Furthermore, it is difficult to predict how future environmental regulations may affect the costs associated with the removal, disposal and recycling of our solar energy systems. Consequently, if the residual value of the systems is less than we expect at the end of the lease, after giving effect to any associated removal and redeployment costs, we may be required to accelerate all or some of the remaining unamortized expenses. This could materially impair our future operating results.

Compliance with environmental regulations can be expensive, and noncompliance with these regulations may result in adverse publicity and potentially significant monetary damages and fines.

We are required to comply with all foreign, federal, state and local laws and regulations regarding pollution control and protection of the environment. In addition, under some statutes and regulations, a government agency, or other parties, may seek recovery and response costs from operators of property where releases of hazardous substances have occurred or are ongoing, even if the operator was not responsible for such release and not otherwise at fault. While we and the State of New York have performed environmental diligence relating to the construction of the Manufacturing Facility, the site where the Manufacturing Facility is to be located is on the former site of Republic Steel and has been considered a "brownfield."

The operation of Silevo's manufacturing and research and development facilities, including in Hangzhou, China, Buffalo, New York and Fremont, California, involves the use of hazardous chemicals and materials which may subject us to liabilities for any releases or other failures to comply with applicable laws, regulations and policies. Any failure by us to maintain effective controls regarding the use of hazardous materials or to obtain and maintain all necessary permits could subject us to potentially significant fines and damages or interrupt our operations.

Product liability claims against us could result in adverse publicity and potentially significant monetary damages.

We would be exposed to product liability claims if one of our solar energy systems or other products injured someone. Because solar energy systems and many of our other current and anticipated products are electricity-producing devices, it is possible that consumers could be injured by our products for many reasons, including product malfunctions,

defects or improper installation. We rely on our general liability insurance to cover product liability claims and have not obtained separate product liability insurance. Any product liability claim we face could be expensive to defend and could divert management's attention. Any product liability claims against us and any resulting adverse outcomes could result in potentially significant monetary damages that could require us to make significant payments, as well as subject us to adverse publicity, damage our reputation and competitive position or adversely affect sales of our systems and other products.

Damage to our brand and reputation would harm our business and results of operations.

We depend significantly on our reputation for high-quality products and services, best-in-class engineering, exceptional customer service and the brand name "SolarCity" to attract new customers and grow our business. Our brand and reputation could be significantly impaired if we fail to continue to deliver our solar energy systems and our other energy products and services within the planned timelines, if our products and services do not perform as anticipated or if we damage any of our customers' properties or cancel projects. In addition, if we fail to deliver, or fail to continue to deliver, high-quality products and services to our customers through our long-term relationships, our customers will be less likely to purchase future products and services from us, which is a key strategy to achieve our desired growth. In addition to our other marketing efforts, we also depend greatly on referrals from existing customers for our growth. Therefore, our inability to meet or exceed our current customers' expectations would harm our reputation and growth through referrals.

If we fail to manage our recent and future growth effectively, we may be unable to execute our business plan, maintain high levels of customer service or adequately address competitive challenges.

We have experienced significant growth in recent periods and we intend to continue to expand our business significantly within existing markets and in a number of new foreign and domestic locations in the future. This growth has placed, and any future growth may place, a significant strain on our management, operational and financial infrastructure. In particular, we will be required to expand, train and manage our growing employee base. Our management will also be required to maintain and expand our relationships with customers, suppliers and other third parties and attract new customers and suppliers, as well as to manage multiple geographic locations and regulatory requirements.

In addition, our current and planned operations, personnel, systems and procedures might be inadequate to support our future growth and may require us to make additional unanticipated investments in our infrastructure. Our success and ability to further scale our business will depend in part on our ability to manage these changes in a cost-effective and efficient manner. If we cannot manage our growth, we may be unable to take advantage of market opportunities, execute our business strategies or respond to competitive pressures. This could also result in declines in quality or customer satisfaction, increased costs, difficulties in introducing new products and services or other operational difficulties. Any failure to effectively manage growth could adversely impact our business and reputation.

We may not be successful in leveraging our customer base to grow our business through sales of other energy products and services.

To date, we have derived substantially all of our revenue and cash receipts from the sale of solar energy systems and the sale of energy under our long-term customer agreements. While we continue to develop and offer innovative energy-related products and services, such as our Demand Logic and residential energy storage products, customer demand for these offerings may be more limited than we anticipate. We may not be successful in completing development of these products as a result of research and development difficulties, technical issues, regulatory issues, availability of third-party products or other reasons. Even if we are able to offer these or other additional products and services, we may not successfully generate meaningful customer demand to make these offerings viable. Our growth will be limited if we fail to deliver these additional products and services, if the costs associated with bringing these additional products and services to market is greater than we anticipate, if customer demand for these offerings is smaller than we anticipate or if our strategies to implement new sales approaches and acquire new customers are not successful.

Our growth depends in part on the success of our strategic relationships with third parties.

A key component of our growth strategy is to develop or expand our strategic relationships with third parties. For example, in an effort to generate new customers, we are investing resources in establishing relationships with leaders in other industries, such as trusted retailers and commercial homebuilders. Identifying partners and negotiating relationships requires significant time and resources. Our ability to grow our business could be impaired if we are unsuccessful in establishing or maintaining our relationships with these third parties. Even if we are able to establish these relationships, we may not be able to execute our goal of leveraging these relationships to meaningfully expand our business and customer base. This would limit our growth potential and our opportunities to generate significant additional revenue or cash receipts.

The loss of one or more members of our senior management or key employees may adversely affect our ability to implement our strategy.

We depend on our experienced management team and the loss of one or more key executives could have a negative impact on our business. In particular, we are dependent on the services of our chief executive officer and co-founder, Lyndon R. Rive, and our chief technology officer and co-founder, Peter J. Rive. We also depend on our ability to retain and motivate key employees and attract qualified new employees. Our founders and our key employees are not bound by employment agreements for any specific term, and as a result, we may be unable to replace key members of our management team and key employees in the event we lose their services. Integrating new employees into our management team could prove disruptive to our operations, require substantial resources and management attention and ultimately prove unsuccessful. An inability to attract and retain sufficient managerial personnel who have critical industry experience and relationships could limit or delay our strategic efforts, which could have a material adverse effect on our business, financial condition and results of operations.

The production and installation of solar energy systems depends heavily on suitable meteorological conditions. If meteorological conditions are unexpectedly unfavorable, the electricity production from our solar energy systems may be substantially below our expectations and our ability to timely deploy new systems may be adversely impacted.

The energy produced and revenue and cash receipts generated by a solar energy system depend on suitable solar and weather conditions, both of which are beyond our control. Furthermore, components of our systems, such as panels and inverters, could be damaged by severe weather, such as hailstorms or tornadoes. In these circumstances, we generally would be obligated to bear the expense of repairing or replacing the damaged solar energy systems that we own. Sustained unfavorable weather also could unexpectedly delay our installation of solar energy systems, leading to increased expenses and decreased revenue and cash receipts in the relevant periods. For example, certain states in which we operate, such as New York and Massachusetts, commonly experience inclement winter weather, and the impacts of significant rainfall from El Niño are expected to continue to impact our operations in California, Mexico and other areas. Weather patterns could change, making it harder to predict the average annual amount of sunlight striking each location where we install. This could make our solar energy systems less economical overall or make individual systems less economical. Any of these events or conditions could harm our business, financial condition and results of operations.

Our business may be harmed if we fail to properly protect our intellectual property.

We believe that the success of our business depends in part on our proprietary technology, including our hardware, software, information, processes and know-how. We rely on many forms of intellectual property rights to secure our technology, including trade secrets and patents. We cannot be certain that we have adequately protected or will be able to adequately protect our technology, that our competitors will not be able to use our existing technology or develop similar technology independently, that any patents or other intellectual property rights held by us will be broad enough to protect our technology or that foreign intellectual property laws will adequately protect us. Moreover, our patents and other intellectual property rights may not provide us with a competitive advantage.

Despite our precautions, it may be possible for third parties to obtain and use our intellectual property without our consent. Reverse engineering, unauthorized use or other misappropriation of our proprietary technology could enable third parties to benefit from our technology without compensating us for doing so. In addition, our proprietary technology may not be adequately protected because:

- our systems may be subject to intrusions, security breaches or targeted thefts of our trade secrets;
- people may not be deterred from misappropriating our technology despite the existence of laws or contracts prohibiting it;
- unauthorized use of our intellectual property may be difficult to detect and expensive and time-consuming to remedy, and any remedies obtained may be inadequate to restore protection of our intellectual property;
- the laws of other countries in which we manufacture our solar products, such as Silevo's joint venture manufacturing company with partners in China and other countries in the Asia/Pacific region, may offer little or no protection for our proprietary technology; and
- reports we may be required to file in connection with any government-sponsored research contracts may disclose some of our sensitive confidential information because they are or will be generally available to the public.

Any such activities or any other inabilities to adequately protect our proprietary rights could harm our ability to compete, to generate revenue and to grow our business.

Claims of patent and other intellectual property infringement are complex and their outcomes are uncertain, and the costs associated with such claims may be high and could harm our business.

Our success in operating our business, including operation of the Manufacturing Facility, depends largely on our ability to use and develop our proprietary technologies and manufacturing know-how without infringing or misappropriating the intellectual property rights of third parties, many of whom have robust patent portfolios, greater capital resources and decades of manufacturing experience. In addition, as we have gained greater visibility and market exposure as a public company, we face a higher risk of being the subject of intellectual property infringement claims. Any claim of infringement by a third party, even those without merit, could cause us to incur substantial legal costs defending against the claim and could distract our management and technical personnel from our business. In particular, the validity and scope of claims relating to photovoltaic technology patents may be highly uncertain because they involve complex scientific, legal and factual considerations and analysis. Furthermore, we could be subject to a judgment or voluntarily enter into a settlement, either of which could require us to pay substantial damages. A judgment or settlement could also include an injunction, a court order or other agreement that could prevent us from operating the Manufacturing Facility and producing our products. In addition, we might elect or be required to seek a license for the use of third-party intellectual property, which may not be available on commercially reasonable terms or at all, or if available, the payments under such license may harm our operating results and financial condition. Alternatively, we may be required to develop non-infringing technology, redesign our products or alter our manufacturing techniques and processes, each of which could require significant research and development efforts and expenses and may ultimately not be successful. Any of these events could seriously harm our business, operating results and financial condition.

We are subject to legal proceedings and regulatory inquiries and we may be named in additional claims or legal proceedings or become involved in regulatory inquiries, all of which are costly, distracting to our core business and could result in an unfavorable outcome or a material adverse effect on our business, financial condition, results of operations or the trading price for our securities.

We are involved in claims, legal proceedings (such as the class action and derivative lawsuits filed against us) and receive inquiries from government and regulatory agencies (such as the pending Treasury and Department of Labor investigations) that arise from the normal business activities. In addition, from time to time, third parties may assert claims against us. We evaluate all claims, lawsuits and investigations with respect to their potential merits, our potential defenses and counter claims, settlement or litigation potential and the expected effect on us. In the event that we are involved in significant disputes or are the subject of a formal action by a regulatory agency, we could be exposed to costly and time-consuming legal proceedings that could result in any number of outcomes. Although outcomes of such actions vary, any claims, proceedings or regulatory actions initiated by or against us, whether successful or not, could result in expensive costs of defense, costly damage awards, injunctive relief, increased costs of business, fines or orders to change certain business practices, significant dedication of management time, diversion of significant operational resources or some other harm to our business. In any of these cases, our business, financial condition, results of operations or the trading price for our securities could be negatively impacted.

We make a provision for a liability relating to legal matters when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed at least quarterly and adjusted to reflect the impacts of negotiations, estimated settlements, legal rulings, advice of legal counsel and other information and events pertaining to a particular matter. In our opinion, resolution of all current matters is not expected to have a material adverse impact on our business, financial condition or results of operations. However, depending on the nature and timing of any such controversy, an unfavorable resolution of a matter could materially affect our future business, financial condition or results of operations, or all of the foregoing, in a particular quarter.

We typically bear the risk of loss and the cost of maintenance and repair on solar systems that are owned or leased by our fund investors.

We typically bear the risk of loss and are generally obligated to cover the cost of maintenance and repair on any solar systems that we sell or lease to our fund investors. At the time we sell or lease a solar system to a fund investor, we enter into a maintenance services agreement where we agree to operate and maintain the system for a fixed fee that is calculated to cover our future expected maintenance costs. If our solar systems require an above-average amount of repairs or if the cost of repairing systems were higher than our estimate, we would need to perform such repairs without additional compensation. If our solar systems, a majority of which are located in California, are damaged in the event of a natural

disaster beyond our control, losses could be excluded, such as earthquake damage, or exceed insurance policy limits, and we could incur unforeseen costs that could harm our business and financial condition. We may also incur significant costs for taking other actions in preparation for, or in reaction to, such events. We purchase Property and Business Interruption insurance with industry standard coverage and limits approved by an investor's third-party insurance advisors to hedge against such risk, but such coverage may not cover our losses.

Any unauthorized disclosure or theft of personal customer information we gather, store and use could harm our reputation and subject us to claims or litigation.

We receive, store and use personal information of our customers, including names, addresses, e-mail addresses, credit information and other housing and energy use information. Unauthorized disclosure of such personal information could harm our business, whether through breach of our systems by an unauthorized party, employee theft or misuse, or otherwise. If we were subject to an inadvertent disclosure of such personal information or if a third party were to gain unauthorized access to customer personal information in our possession, our operations could be seriously disrupted and we could be subject to claims or litigation arising from damages suffered by our customers. In addition, we could incur significant costs in complying with the multitude of federal, state and local laws regarding the unauthorized disclosure of personal customer information. Finally, any perceived or actual unauthorized disclosure of such information could harm our reputation, substantially impair our ability to attract and retain customers and have an adverse impact on our business.

Any failure to comply with laws and regulations relating to our interactions with current or prospective residential customers could result in negative publicity, claims, investigations, and litigation, and adversely affect our financial performance.

As the country's largest residential solar installer, we rely on our ability to engage in transactions with residential customers. In doing so, we must comply with numerous federal, state and local laws and regulations that govern matters relating to our interactions with residential consumers, including those pertaining to privacy and data security, consumer financial and credit transactions, home improvement contracts, warranties and door-to-door solicitation. These laws and regulations change frequently and are interpreted by various federal, state and local regulatory bodies. Changes in these laws or regulations or their interpretation could dramatically affect how and where we conduct our business, acquire customers, and manage and use information we collect from and about current and prospective customers and the costs associated therewith.

Even though we may believe that we maintain effective compliance with all such laws and regulations, we may still be subject to claims, proceedings, litigation and investigations by private parties and regulatory authorities, and could be subject to substantial fines and negative publicity, each of which may materially and adversely affect our business and operations. For example, a putative class action was filed against us in November 2015 alleging violations of the federal Telephone Consumer Protection Act. We have incurred, and will continue to incur, significant expenses to comply with such laws and regulations, and increased regulation of matters relating to our interactions with residential consumers could require us to modify our operations and incur significant additional expenses, which could have an adverse effect on our business, financial condition and results of operations.

In addition, we are subject to federal, state and international laws relating to the collection, use, retention, security and transfer of personal information of our customers. In many cases, these laws apply not only to third-party transactions, but also to transfers of information between one company and its subsidiaries. Several jurisdictions have passed new laws in this area, and other jurisdictions are considering imposing additional restrictions. These laws continue to develop and may be inconsistent from jurisdiction to jurisdiction. Complying with emerging and changing requirements may cause us to incur costs or require us to change our business practices. Any failure by us, our affiliates or other parties with whom we do business to comply with a posted privacy policies or with other federal, state or international privacy-related or data protection laws and regulations could result in proceedings against us by governmental entities or others, which could have a detrimental effect on our business, results of operations and financial condition.

Risks Related to the Ownership of Our Common Stock

Our stock price has been and may continue to be volatile, and the value of your investment could decline.

The trading price of our common stock has been volatile since our initial public offering. Since shares of our common stock were sold in our initial public offering in December 2012 at a price of $8.00 per share, the reported high and low sales prices of our common stock on The NASDAQ Stock Market has ranged from $9.20 to $88.35 per share, through February 9, 2016. The market price of our common stock may fluctuate widely in response to many risk factors listed in this section and others beyond our control, including:

- changes in laws or regulations applicable to our industry, products or services, including the effects of tariffs and other anti-competitive actions;

- additions or departures of key personnel;
- actual or anticipated changes in expectations regarding our performance by investors or securities analysts;
- price and volume fluctuations in the overall stock market;

- volatility in the market price and trading volume of companies in our industry or companies that investors consider comparable;
- share price and volume fluctuations attributable to inconsistent trading volume levels of our shares;
- addition or loss of significant customers;
- our ability to protect our intellectual property and other proprietary rights;
- sales of our common stock by us or our stockholders, including as a result of recent, proposed or new offerings and acquisitions;
- litigation involving us, our industry or both;
- major catastrophic events; and
- general economic and market conditions and trends.

Further, in recent years the stock markets have experienced extreme price and volume fluctuations that have affected and continue to affect the market prices of equity securities of many companies. These fluctuations often have been unrelated or disproportionate to the operating performance of those companies. In addition, the stock prices of many renewable energy companies have experienced wide fluctuations that have often been unrelated to the operating performance of those companies. These broad market and industry fluctuations, as well as general economic, political and market conditions such as recessions, government shutdowns, interest rate changes or international currency fluctuations, may cause the market price of our common stock to decline. In the past, companies that have experienced volatility in the market price of their stock have been subject to securities class action litigation. We may be the target of this type of litigation in the future. Securities litigation against us could result in substantial costs and divert our management's attention from other business concerns, which could seriously harm our business.

Our stock price could decline due to the large number of outstanding shares of our common stock eligible for future sale and issuance.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales could occur, could cause the market price of our common stock to decline. These sales could also make it more difficult for us to sell equity or equity-related securities in the future at a time and price that we deem appropriate. Such sales may occur in connection with our acquisitions, such as our issuance of approximately 8.8 million shares in the aggregate for our acquisitions of Silevo, Zep Solar and certain assets of Paramount Solar. In connection with our acquisition of Silevo, we may issue additional common stock with an aggregate value of up to $150.0 million, subject to adjustments and as determined in connection with the merger agreement, upon the timely achievement of all earnout related milestones. In addition, holders of a substantial amount of our common stock are entitled to rights with respect to registration of these shares under the Securities Act pursuant to an investors' rights agreement. If these holders of our common stock, by exercising their registration rights, sell a large number of shares, they could adversely affect the market price for our common stock. If we file a registration statement for the purposes of selling additional shares to raise capital and are required to include shares held by these holders pursuant to the exercise of their registration rights, our ability to raise capital may be impaired.

Insiders have substantial control over us, which could limit your ability to influence the outcome of key transactions, including a change of control.

As of December 31, 2015, our directors and executive officers and their affiliates, in the aggregate, owned approximately 35% of the outstanding shares of our common stock. As a result, these stockholders, if acting together, would be able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers, acquisitions or other extraordinary transactions. They may have interests that differ from yours and may vote in a way with which you disagree and that may be adverse to your interests. This concentration of ownership may have the effect of delaying, preventing or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company and might affect the market price of our common stock.

Provisions in our certificate of incorporation and bylaws and under Delaware law might discourage, delay or prevent a change of control of our company or changes in our management and, therefore, depress the trading price of our common stock.

Our certificate of incorporation and bylaws contain provisions that could depress the trading price of our common stock by discouraging, delaying or preventing a change of control of our company or changes in our management that the stockholders of our company may believe advantageous. These provisions include:

- establishing a classified board of directors with three-year staggered terms, which could delay the ability of stockholders to change the membership of a majority of our board of directors;
- authorizing "blank check" preferred stock that our board of directors could issue to increase the number of outstanding shares to discourage a takeover attempt;
- limiting the ability of stockholders to call a special stockholder meeting;
- limiting the ability of stockholders to act by written consent;
- authorizing the board of directors to make, alter or repeal our bylaws; and
- establishing advance notice requirements for nominations for elections to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

If securities or industry analysts cease publishing research or reports about us, our business or our market, or if they adversely change their recommendations regarding our stock, our stock price and trading volume could decline.

The trading market for our common stock, to some extent, depends on the research and reports that industry or securities analysts may publish about us, our business, our market or our competitors. If any of the analysts who cover us adversely change their recommendation regarding our stock, or provide more favorable relative recommendations about our competitors, our stock price would likely decline. If any analyst who covers us were to cease coverage of our company or fail to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline.

We do not intend to pay dividends for the foreseeable future.

We have never declared or paid any dividends on our common stock. We intend to retain any earnings to finance the operation and expansion of our business and do not anticipate paying any cash dividends in the future. As a result, you may only receive a return on your investment in our common stock if the market price of our common stock increases.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Our corporate headquarters and executive offices are located in San Mateo, California, where we occupy approximately 68,025 square feet of office space under a lease that expires in December 2016, with a renewal option. We also maintain a regional headquarters in Salt Lake City, Utah, as well as larger offices in San Francisco, San Rafael and Fremont, California. In addition, we lease sales offices, warehouses and manufacturing facilities across the country and in Mexico and China. We also maintain sales and support offices in Ontario, Canada. We lease all of our facilities, and we do not own any real property. We believe that our existing facilities are adequate for our current needs and that we will be able to lease suitable additional or alternative space on commercially reasonable terms if and when we need it.

ITEM 3. LEGAL PROCEEDINGS

In July 2012, we, along with other companies in the solar energy industry, received a subpoena from the U.S. Treasury Department's Office of the Inspector General to deliver certain documents in our possession that were dated, created, revised or referred to after January 1, 2007 and that relate to our applications for U.S. Treasury grants or communications with certain other solar energy development companies or with certain firms that appraise solar energy property for U.S Treasury grant application purposes. The Inspector General and the Civil Division of the U.S. Department of Justice are investigating the administration and implementation of the U.S Treasury grant program, including possible misrepresentations concerning the fair market value of the solar energy systems submitted by us in U.S. Treasury grant applications. If the Inspector General concludes that misrepresentations were made, the U.S. Department of Justice could decide to bring a civil action to recover amounts it believes were improperly paid to us. If the U.S. Department of Justice is successful in asserting this action, we could then be required to pay material damages and penalties for any funds received based on such misrepresentations, which, in turn, could require us to make indemnity payments to certain fund investors. We are unable to estimate the possible loss, if any, associated with this ongoing investigation.

On March 28, 2014, a purported stockholder class action was filed in the United States District Court for the Northern District of California against us and two of our officers. The complaint alleges claims for violations of the federal securities laws, and seeks unspecified compensatory damages and other relief on behalf of a purported class of purchasers of our securities from March 6, 2013 to March 18, 2014. On April 16, 2015, the District Court dismissed the complaint and allowed the plaintiffs to file an amended complaint in an attempt to remedy the defects in the original complaint. The plaintiffs filed their amended complaint, and we filed a renewed motion to dismiss on August 7, 2015. On January 5, 2016, the District Court dismissed the amended complaint and allowed the plaintiffs until February 15, 2016 to file a further amended complaint in an attempt to remedy the defects in the amended complaint. We believe that the claims are without merit and intends to defend ourselves vigorously. We are unable to estimate the possible loss, if any, associated with this lawsuit.

On June 5 and 11, 2014, stockholder derivative actions were filed in the Superior Court of California for the County of San Mateo, purportedly on behalf of us and against our board of directors, alleging that our board of directors breached their duties to us by failing to prevent the conduct alleged in the pending purported stockholder class action lawsuit. We and the individual board member defendants filed a motion to dismiss the complaint, which the Superior Court granted on December 17, 2015. The Superior Court allowed the plaintiffs until February 24, 2016 to file an amended complaint in an attempt to remedy the defects in the original complaint. The Superior Court scheduled a hearing on June 10, 2016 for any motion by our board of directors or us to dismiss the amended complaint. We will continue to review the claims asserted by the stockholders and are unable to estimate the possible loss, if any, associated with this lawsuit.

In June 2014, we along with Sunrun, Inc., or Sunrun, filed a lawsuit in the Superior Court of Arizona against the Arizona Department of Revenue, or DOR, challenging DOR's interpretation of Arizona state law to impose property taxes on solar energy systems that are leased by customers. On June 1, 2015, the Superior Court issued an order rejecting the interpretation of the Arizona state law under which the DOR had sought to tax leased solar energy systems. In that same order, the Superior Court held that a separate Arizona statute, which provides that such systems are deemed to have no value for purposes of calculating property tax, violated certain provisions of the Arizona state constitution. Both the DOR and we have appealed the Superior Court's ruling, and we will continue to vigorously pursue our claims.

On March 2, 2015, we filed a lawsuit in the United States District Court for the District of Arizona against the Salt River Project Agricultural Improvement and Power District and the Salt River Valley Water Users' Association, or SRP, alleging that SRP's imposition of distribution charges and demand charges on new solar energy customers in its territory violates state and federal antitrust laws. On June 23, 2015, SRP moved to dismiss the complaint. On October 27, 2015, the District Court denied SRP's motion to dismiss in part and granted it in part. In particular, the District Court held that we may proceed on our antitrust claims against SRP to seek an injunction blocking SRP's new charges and may proceed with claims for damages under state laws other than antitrust laws. Furthermore, the District Court held that we may not recover monetary damages on our antitrust theories and dismissed two of our antitrust claims while allowing the others to proceed. Discovery has commenced, and we intend to pursue our claims vigorously.

On September 18, 2015, a stockholder derivative action was filed in the Court of Chancery of the State of Delaware, purportedly on behalf of us and against our board of directors, alleging that our board of directors breached their duties to us by approving stock-based compensation to the non-employee directors that the plaintiff claims is excessive compared

to the compensation paid to directors of peer companies. We are reviewing the claim and are unable to estimate the possible loss, if any, associated with this lawsuit.

On September 21, 2015, we filed a lawsuit in the United States District Court for the District of Massachusetts against Seaboard Solar Operations LLC, or Seaboard, and its principal, Stuart Longman, alleging breaches of the various written contracts between us and Seaboard, fraud, conversion and unfair business practices. We sought a declaratory judgment that we own and have the right to develop the specified projects and of damages of approximately $16.0 million. In December 2015, we settled the lawsuit in exchange for $16.1 million to be paid by Seaboard over the course of 2016; upon making those payments, Seaboard will have the rights to the projects.

On November 6, 2015, a putative class action was filed against us in the United States District Court for the Northern District of California. The complaint alleges that we made unlawful telephone marketing calls to the plaintiff and others, in violation of the federal Telephone Consumer Protection Act. The plaintiff seeks injunctive relief and statutory damages, on behalf of himself and a certified class. On January 25, 2016, we filed a motion to dismiss the complaint. We believe that the claims are without merit and intend to defend ourselves vigorously. We are unable to estimate the possible loss, if any, associated with this lawsuit.

From time to time, claims have been asserted, and may in the future be asserted, including claims from regulatory authorities related to labor practices and other matters. Such assertions arise in the normal course of our operations. The resolution of any such assertions or claims cannot be predicted with certainty. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our results of operations, prospects, cash flows, financial position and brand.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER REPURCHASES OF EQUITY SECURITIES

Market Information

Our common stock, $0.0001 par value per share, began trading on the NASDAQ Global Select Market on December 13, 2012, where its prices are quoted under the symbol "SCTY."

Holders of Record

As of December 31, 2015, there were 233 holders of record of our common stock. Because many of our shares of common stock are held by brokers and other institutions on behalf of stockholders, we are unable to estimate the total number of stockholders represented by these record holders.

Price Range of Our Common Stock

The following table sets forth the reported high and low sales prices of our common stock for the indicated periods, as regularly quoted on the NASDAQ Global Select Market:

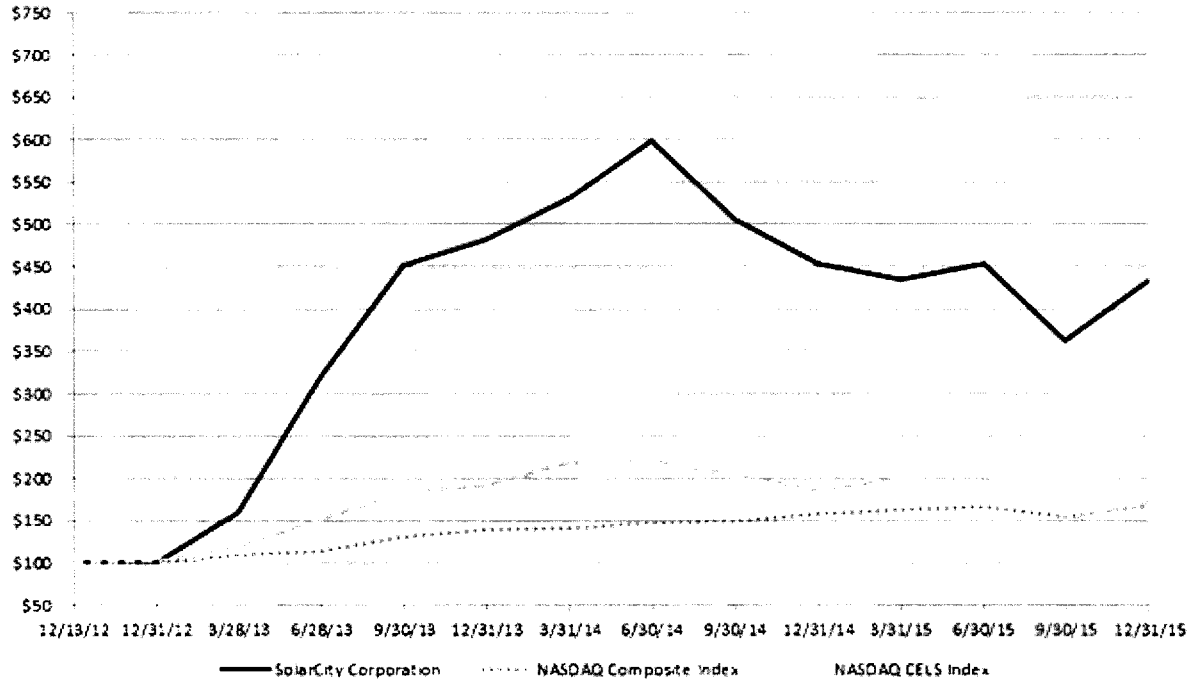
	Year Ended December 31, 2014		Year Ended December 31, 2015	
	High	Low	High	Low
First Quarter	$ 88.35	$ 55.56	$ 59.31	$ 46.45
Second Quarter	$ 72.10	$ 45.79	$ 63.79	$ 50.00
Third Quarter	$ 79.40	$ 58.43	$ 61.72	$ 34.65
Fourth Quarter	$ 61.09	$ 45.91	$ 58.87	$ 24.07

We have never declared or paid cash dividends on our capital stock. We currently intend to retain all available funds and any future earnings for use in the operation of our business and do not anticipate paying any cash dividends in the foreseeable future. Any decision to declare and pay dividends in the future will be made at the discretion of our board of directors and will depend on, among other things, our results of operations, cash requirements, financial condition, contractual restrictions including compliance with covenants under our credit facilities and other factors that our board of directors may deem relevant.

Stock Price Performance Graph

This performance graph shall not be deemed "filed" for purposes of Section 18 of the Exchange Act, or incorporated by reference into any filing of SolarCity Corporation under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

This chart compares the cumulative total return on our common stock with that of the NASDAQ Composite Index and the NASDAQ Clean Edge U.S. Liquid Series Index, or NASDAQ CELS Index. The chart assumes $100 was invested on December 13, 2012 in the common stock of SolarCity Corporation, the NASDAQ Composite Index and the NASDAQ CELS Index, and assumes the reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.



Company/Index	Base Period 12/13/2012	Indexed Returns Period ended 12/31/2013	Indexed Returns Period ended 12/31/2014	Indexed Returns Period ended 12/31/2015
SolarCity Corporation	$ 100.00	$ 481.93	$ 453.60	$ 432.74
NASDAQ Composite Index	$ 100.00	$ 139.58	$ 158.28	$ 167.35
NASDAQ Clean Edge U.S. Liquid Series Index	$ 100.00	$ 192.30	$ 185.30	$ 171.76

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

You should read the following selected consolidated financial data below in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and the consolidated financial statements, the accompanying notes and other financial information included elsewhere in this annual report on Form 10-K. The selected consolidated financial data in this section are not intended to replace the consolidated financial statements and are qualified in their entirety by the consolidated financial statements and the accompanying notes included elsewhere in this annual report on Form 10-K.

The consolidated statements of operations data for the years ended December 31, 2015, 2014 and 2013 and the consolidated balance sheets data as of December 31, 2015 and 2014 are derived from our audited consolidated financial statements included elsewhere in this annual report on Form 10-K. The consolidated statements of operations data for the years ended December 31, 2012 and 2011 and the consolidated balance sheets data as of December 31, 2013, 2012 and 2011 are derived from our audited consolidated financial statements not included in this annual report on Form 10-K, which are stated on a basis consistent with our audited consolidated financial statements included herein. Our historical results are not necessarily indicative of the results that may be expected in any future period.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share amounts)				
Consolidated statement of operations data:					
Revenue:					
Operating leases and solar energy systems incentives	$ 293,543	$ 173,636	$ 82,856	$ 46,098	$ 23,145
Solar energy systems and component sales	106,076	81,395	80,981	80,810	36,406
Total revenue	399,619	255,031	163,837	126,908	59,551
Cost of revenue:					
Operating leases and solar energy systems incentives	165,546	92,920	32,745	14,596	5,718
Solar energy systems and component sales	115,245	83,512	91,723	84,856	41,418
Total cost of revenue	280,791	176,432	124,468	99,452	47,136
Gross profit	118,828	78,599	39,369	27,456	12,415
Net loss	(768,822)	(375,230)	(151,758)	(113,726)	(73,714)
Net loss attributable to noncontrolling interests and redeemable noncontrolling interests(1)	(710,492)	(319,196)	(95,968)	(14,391)	(117,230)
Net (loss) income attributable to stockholders(1)	$ (58,330)	$ (56,034)	$ (55,790)	$ (99,335)	$ 43,516
Net (loss) income per share attributable to common stockholders:					
Basic	$ (0.60)	$ (0.60)	$ (0.70)	$ (7.68)	$ 0.82
Diluted	$ (0.60)	$ (0.60)	$ (0.70)	$ (7.69)	$ 0.76

(1) Under U.S. generally accepted accounting principles, we are required to present the impact of a hypothetical liquidation of our joint ventures on our consolidated statements of operations. For a more detailed discussion of this accounting treatment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Components of Results of Operations—Net Income (Loss) Attributable to Stockholders."

	As of December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Consolidated balance sheet data:					
Cash and cash equivalents	$ 382,544	$ 504,383	$ 577,080	$ 160,080	$ 50,471
Total current assets	$ 902,138	$ 997,616	$ 785,924	$ 313,938	$ 241,522
Solar energy systems, leased and to be leased - net	$ 4,375,553	$ 2,796,796	$ 1,682,521	$ 984,121	$ 535,609
Total assets	$ 7,287,118	$ 4,551,219	$ 2,792,120	$ 1,335,592	$ 812,703
Total current liabilities	$ 1,193,362	$ 566,513	$ 338,029	$ 213,939	$ 246,886
Long-term debt, net of current portion	$ 1,006,595	$ 282,789	$ 231,504	$ 76,864	$ 14,111
Convertible senior notes, net of current portion	$ 894,560	$ 777,726	$ 222,827	$ —	$ —
Solar asset-backed notes, net of current portion	$ 395,667	$ 293,215	$ 46,824	$ —	$ —
Deferred revenue, net of current portion	$ 1,010,491	$ 557,408	$ 410,161	$ 204,396	$ 101,359
Financing obligation, net of current portion	$ 68,940	$ 73,379	$ 78,505	$ 140,639	$ 61,685
Other liabilities and deferred credits	$ 279,006	$ 218,024	$ 193,439	$ 114,006	$ 36,314
Redeemable noncontrolling interests in subsidiaries	$ 320,935	$ 186,788	$ 44,709	$ 12,827	$ 22,308
Convertible redeemable preferred stock	$ —	$ —	$ —	$ —	$ 125,722
Total stockholders' equity (deficit)	$ (316,680)	$ 745,642	$ 617,598	$ 183,601	$ (37,662)
Noncontrolling interests in subsidiaries	$ 535,062	$ 409,942	$ 186,817	$ 96,793	$ 100,338

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the accompanying notes to those statements included elsewhere in this annual report on Form 10-K. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results and timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors" and elsewhere in this annual report on Form 10-K.

Overview

We integrate the sales, engineering, manufacturing, installation, monitoring, maintenance and financing of our distributed solar energy systems. This allows us to offer long-term energy solutions to residential, commercial, government and other customers. We make it possible for our customers to buy renewable energy or solar energy systems from us for less than they currently pay for electricity from utilities with little to no up-front cost or down payment, as applicable. Our long-term contractual arrangements typically generate recurring customer payments, provide our customers with insight into their future electricity costs and minimize their exposure to rising retail electricity rates. We also offer energy-related products and services to our customers, such as energy storage solutions. To date, revenue attributable to our energy-related products and services has not been material.

We offer our customers the choice to either purchase and own solar energy systems or to purchase the energy that our solar energy systems produce through various contractual arrangements. These contractual arrangements include long-term leases and power purchase agreements. In both structures, we install our solar energy systems at our customer's premises and charge the customer a monthly fee for the power that our system produces. In the lease structure, this monthly payment is fixed with a production guarantee. In the power purchase agreement structure, we charge customers a fee per kilowatt-hour, or kWh, based on the amount of electricity the solar energy system actually produces. The leases and power purchase agreements are typically for 20 years with a renewal option, and generally when there is no upfront prepayment, the specified monthly fees are subject to annual escalations.

Initially, we only offered our solar energy systems on an outright purchase basis. During 2008, we began offering leases and power purchase agreements. In the fourth quarter of 2014, we began offering MyPower. Under MyPower, we provide qualified residential customers with a 30-year loan to finance the purchase of a solar energy system. The interest rate on the loan is fixed at inception and ranges from 4.50% to 5.49% per annum, depending on the geographic market. The interest rates are reduced by 0.50% per annum for customers who elect to have their payments automatically withdrawn. The monthly loan repayments are variable based on the amount of electricity generated by the systems. The customers are eligible to receive a federal income tax credit equal to 30% of the value of the solar energy system, which the customers can, and in certain cases are contractually obligated to, use to pay down the loan principal, and lower future monthly loan payments. This in turn translates to a lower effective cost per kWh of electricity to these customers. Our ability to offer leases, power purchase agreements and the financing of systems under MyPower depends in part on our ability to monetize the resulting customer receivables and any related investment tax credits, or ITCs, accelerated tax depreciation and other incentives.

We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide and payments under MyPower below that rate. As a result, the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region because utilities' commercial retail rates are generally lower than their residential retail rates.

We generally recognize revenue from solar energy systems sold to our customers on an outright purchase basis when we install the solar energy system and it passes inspection by the utility or the authority having jurisdiction. We recognize revenue from MyPower financed sales over the term of the loan contract as the customer pays the loan's outstanding principal and interest. We account for our leases and power purchase agreements as operating leases. We recognize the revenue that these arrangements generate on a straight-line basis over the term for leases, and as we generate and deliver energy for power purchase agreements. We recognize revenue from our energy-related products and services when we complete the services or when we earn a referral fee. Substantially all of our revenue is attributable to customers located in the United States.

We monetize certain government incentives in the form of ITCs under lease pass-through structures by assigning the ITCs to investors in exchange for upfront cash payments. We record the amounts we receive from the investors for the ITCs as a liability, which is subsequently recognized as revenue as the five-year ITC recapture period expires.

The amount of operating lease revenue that we recognize in a given period is dependent in part on the amount of energy generated by solar energy systems under power purchase agreements and by solar energy systems with energy output performance based incentives, which is in turn dependent on the amount of sunlight received by these solar energy systems. Additionally, a portion of the revenue that we recognize in any given period for sales financed under MyPower is derived from the cash receipts from periodic customer billings. The periodic customer billings are based on the amount of electricity generated by these systems, which in turn is dependent in part on the amount of sunlight received by these systems. As a result, operating lease revenue and revenue from sales financed under MyPower are impacted by seasonally shorter daylight hours and inclement weather in winter months. As the relative percentage of our revenue attributable to power purchase agreements, performance-based incentives or financed sales under MyPower increases, this seasonality has and will continue to become more significant to our financial results.

Various state and local agencies offer incentive rebates for the installation and operation of solar energy systems. For solar energy systems we sell, we typically have the customer assign the incentive rebate to us. For outright sales, we record the incentive rebate as a component of proceeds from the solar energy system sale. For incentive rebates associated with solar energy systems under leases or power purchase agreements, we initially record the incentive rebate that is paid upfront as deferred revenue and recognize the deferred revenue as revenue over the term of the lease or power purchase agreement. For incentives that are paid based on the performance of the solar energy systems, we recognize revenue as the solar energy systems produce electricity.

Component materials, direct labor and third-party appliances comprise the substantial majority of the costs of our solar energy systems and energy-related products and services. Under U.S. generally accepted accounting principles, or GAAP, the cost of revenue from our leases and power purchase agreements are primarily comprised of the depreciation of the cost of the solar energy systems, which are depreciated over their estimated useful lives of 30 years, reduced by amortization of U.S. Treasury grants income. The cost of revenue from our leases and power purchase agreements also include the amortization of initial direct costs, which generally include the incremental costs of contract administration, referral fees and sales commissions, which are amortized over the minimum contractual term of the lease or power purchase agreement, which is typically 20 years. The costs associated with sales financed under MyPower, with the exception of warranty costs, are initially deferred as other assets on the balance sheet and subsequently recognized on the statement of operations, in proportion to the reduction of the principal balance of the customer's loan.

The estimated warranty costs associated with sales under MyPower are recognized as an expense upon the delivery of the solar energy systems, while any actual cash payments for these warranty costs would be made in future periods if and when component parts fail and then need to be repaired or replaced. We price our solar energy systems such that we will realize an overall gross profit on the systems over the 30-year term of the MyPower contracts. However, since the revenue associated with sales under MyPower is recognized over the term of the MyPower contracts, recognizing the estimated warranty costs as an expense upfront results in a gross loss being recognized at the inception of the MyPower contracts. As sales under MyPower continue to increase, we expect that the impact of recognizing the warranty expense upfront will continue to adversely affect our gross margins.

We have structured different types of financing funds to implement our asset monetization strategy. One such structure is a joint venture structure where we and our fund investors both contribute funds or assets into the joint venture. In accordance with GAAP, we recognize the impact of a hypothetical liquidation of these joint ventures on our consolidated statements of operations. Therefore, after we determine our consolidated net income (loss) for a given period, we allocate a portion of our consolidated net income (loss) to the fund investors in our joint ventures (referred to as the "noncontrolling interests and redeemable noncontrolling interests" in our consolidated financial statements) and allocate the remainder of the consolidated net income (loss) to our stockholders. These income or loss allocations, reflected on our consolidated statements of operations, can have a significant impact on our reported results of operations. For example, for the years ended December 31, 2015 and 2014, our consolidated net loss was $768.8 million and $375.2 million, respectively. However, after applying the required allocations to arrive at the consolidated net loss attributable to our stockholders, the result was a loss of $58.3 million and $56.0 million in 2015 and 2014, respectively. For a more detailed discussion of this accounting treatment, see "—Components of Results of Operations—Net Income (Loss) Attributable to Stockholders."

We are in the process of making leasehold improvements to a manufacturing facility in Fremont, California, which we began leasing from a third party in 2014. The leasehold improvements include a 100.0-megawatt high-performance solar cell and module production line as well as normal tenant improvements. In the fourth quarter of 2015, we began

limited domestic production of solar cells and modules at this facility, and will also be using the facility for our solar panel research and development activities.

In September 2014, one of our subsidiaries entered into a build-to-suit lease arrangement with the Research Foundation for the State University of New York, or the Foundation, for the construction of an approximately 1.0 million square-feet solar panel manufacturing facility with a capacity of 1.0 gigawatts on an approximately 88.2 acre site located in Buffalo, New York. Under the terms of the arrangement, which has been amended, the Foundation will construct the manufacturing facility and install certain utilities and other improvements, with participation by us as to the design and construction of the manufacturing facility, and acquire certain manufacturing equipment designated by us to be used in the manufacturing facility. The Foundation will cover (i) construction costs related to the manufacturing facility in an amount up to $350.0 million, (ii) the acquisition and commissioning of the manufacturing equipment in an amount up to $348.1 million and (iii) $51.9 million for additional specified scope costs, in cases (i) and (ii) only, subject to the maximum funding allocation from the State of New York, and we will be responsible for any construction and equipment costs in excess of such amounts. The Foundation will own the manufacturing facility and manufacturing equipment purchased by the Foundation. Following completion of the manufacturing facility, we will lease the manufacturing facility and the manufacturing equipment owned by the Foundation from the Foundation for an initial period of 10 years, with an option to renew, for $2 per year plus utilities.

Under the terms of the build-to-suit lease arrangement, we are required to achieve specific operational milestones during the initial term of the lease, which include employing a certain number of employees at the facility, within western New York and within the State of New York within specified time periods following the completion of the facility. We are also required to spend or incur approximately $5.0 billion in combined capital, operational expenses and other costs in the State of New York over the 10 years following the achievement of full production. On an annual basis during the initial lease term, as measured on each anniversary of the commissioning of the facility, if we fail to meet our specified investment and job creation obligations, then we would be obligated to pay a $41.2 million "program payment" to the Foundation for each year that we fail to meet these requirements. Furthermore, if the arrangement is terminated due to a material breach by us, then additional amounts might be payable by us.

In October 2014, we commenced issuing Solar Bonds to the general public, which are senior unsecured obligations that are structurally subordinate to the indebtedness and other liabilities of our subsidiaries. Solar Bonds have various terms and interest rates. We intend to continue to issue Solar Bonds periodically.

On August 7, 2015, we acquired all of the outstanding shares of Ilioss, a designer and marketer of commercial and industrial solar energy systems in Mexico. Historically, Ilioss subcontracted the installation of its solar energy systems and sold them to financing companies along with the related customer power purchase agreements. We have vertically integrated Ilioss' operations, and expect to expand our product offerings throughout Mexico.

Financing Funds

Our lease and power purchase agreements in conjunction with the associated solar energy systems create ITCs, accelerated tax depreciation deductions, customer payments and other incentives. Our current financial strategy is to monetize these attributes or 'assets' to generate cash. Through this monetization process, we are able to share the economic benefits generated by the solar energy system with our customers by lowering the price they pay for energy. Historically, we have monetized the assets created by substantially all of our leases and power purchase agreements via funds we have formed with fund investors. Depending on the structure of the fund, we may contribute or sell solar energy systems to the fund and assign certain of the tax attributes and other incentives associated with the solar energy systems to the investors and in return we receive upfront cash payments from investors.

We also enter into arrangements that allow us to borrow against the future recurring customer payments under the solar system leases and power purchase agreements. Through the financing funds, we are able to retain the residual value in leases and the solar energy systems themselves. We use the cash received from the investors to cover our operating and capital costs including the variable and fixed costs associated with installing the related solar energy systems. Because these recurring customer payments are from individuals or commercial businesses with high credit scores, and because electricity is a necessity, our fund investors perceive these as high-quality assets with a relatively low loss rate. We invest any excess cash in the growth of our business.

Joint Ventures. Under joint venture structures, we and our fund investors contribute assets or cash into a joint venture. Then, the joint venture acquires solar energy systems from us and leases the solar energy systems to customers. Prior to the fund investor receiving its contractual rate of return or for a time period specified in the contractual

arrangements, the fund investors receive substantially all of the value attributable to the long-term recurring customer payments, ITCs, accelerated tax depreciation and, in some cases, other incentives. After the fund investor receives its contractual rate of return or after the specified time period, we receive substantially all of the value attributable to the long-term recurring customer payments and the other incentives.

We have determined that we are the primary beneficiary in these joint venture structures. Accordingly, we consolidate the assets and liabilities and operating results of these joint ventures, including the solar energy systems and operating lease revenue, in our consolidated financial statements. We recognize the fund investors' share of the net assets of the joint ventures as noncontrolling interests in subsidiaries or redeemable noncontrolling interests in subsidiaries in our consolidated balance sheets. We recognize the amounts that are contractually payable to these investors in each period as distributions to noncontrolling interests or redeemable noncontrolling interests in subsidiaries. Our consolidated statements of cash flows reflect cash received from these fund investors as proceeds from investments by noncontrolling interests and redeemable noncontrolling interests in subsidiaries. Our consolidated statements of cash flows also reflect cash paid to these fund investors as distributions paid to noncontrolling interests and redeemable noncontrolling interests in subsidiaries. We reflect any unpaid distributions to these fund investors as distributions payable to noncontrolling interests and redeemable noncontrolling interests in subsidiaries in our consolidated balance sheets.

Lease Pass-Through. Under lease pass-through structures, we lease solar energy systems to fund investors under a master lease agreement, and these investors in turn sublease the solar energy systems to customers. We receive all of the value attributable to the accelerated tax depreciation and some or all of the value attributable to the other incentives. We assign to the fund investors the value attributable to the ITCs, the right to receive U.S. Treasury Department grants, where applicable, and, for the duration of the master lease term, the long-term recurring customer payments. The investors typically make significant upfront cash payments that we classify and allocate between the right to the ITCs, where applicable, and the future customer lease payments and other benefits assigned to the investor, which are recorded as a lease pass-through financing obligation. After the master lease term expires, we receive the customer payments, if any. We record the solar energy systems on our consolidated balance sheets as a component of solar energy systems, leased and to be leased—net. We record the amounts allocated to the ITCs as deferred revenue on our consolidated balance sheets as the associated solar energy systems are placed in service. We then recognize the deferred revenue in our consolidated statements of operations as revenue from operating leases and solar energy systems incentives, by reducing the deferred revenue balance at each reporting date as the five-year recapture period expires. We record the balance of the amounts received from fund investors as a financing obligation on our consolidated balance sheets and subsequently reduce the obligation by the amounts received by the fund investors from U.S. Treasury Department grants, where applicable, customer payments and the associated incentive rebates. We in turn recognize the incentive rebates and customer payments as revenue over the customer lease term and amortize U.S. Treasury Department grants as a reduction to depreciation of the associated solar energy systems over the estimated life of these systems.

Sale-Leaseback. Under sale-leaseback structures, we generate cash through the sale of solar energy systems to fund investors, and we then lease these systems back from the investors and sublease them to our customers. For the duration of the lease term, we may, for some of the structures, receive the value attributable to the incentives and the long-term recurring customer payments, and we make leaseback payments to the fund investors. The fund investors receive the customer payments after the lease term. They also receive the value attributable to the ITCs, accelerated depreciation and other incentives. At the end of the lease term, we have the option to purchase the solar energy systems from the fund investors at the greater of the fair value or the predetermined agreed upon value. Typically, our customers make monthly lease payments that we recognize as revenue over the term of the subleases on a straight-line basis. Depending on the design, size and construction of the individual systems and the leaseback terms, we may recognize a portion of the revenue from the sale of the systems or we may treat the cash received from the sale as financing received from the fund investors and reflect the cash received as a financing obligation on our consolidated balance sheets.

Securitization. Under securitization arrangements, we pool and transfer qualifying solar energy systems and the associated customer contracts or our interests in specified financing funds into a special purpose entity, or SPE, and issue notes backed by these solar assets to investors. The SPE is wholly owned by us and is consolidated in our consolidated financial statements. Accordingly, we do not recognize a gain or loss on transfer of these assets. The notes bear interest at a rate determined on the issuance of the notes. The cash flows generated by the assets in the SPEs are used to service the principal and interest payments of the notes and meet the SPE's expenses, and any remaining cash is distributed to us. We recognize the revenue earned from the associated customer contracts in our consolidated financial statements. The assets and cash flows generated by the SPE are not available to our other creditors and the creditors of the SPE, including the note holders, have no recourse to our other assets.

Key Operating Metrics

We regularly review a number of metrics, including the following key operating metrics, to evaluate our business, measure our performance, identify trends affecting our business, formulate financial projections and make strategic decisions.

Customers

We track the number of residential, commercial, government and other customers where we have installed or contracted to install a solar energy system, or performed or contracted to perform an energy-related consultation or other energy efficiency services. We believe that the relationship we establish with building owners, together with the energy-related information we obtain about the buildings, position us to provide the owners with additional solutions to further lower their energy costs. We track the cumulative number of customers as of the end of a given period as an indicator of our historical growth and as an indicator of our rate of expected growth from period to period.

The following table sets forth our cumulative number of customers as of the dates presented:

	December 31, 2015	December 31, 2014
Cumulative customers	331,256	189,657

As of December 31, 2015 and December 31, 2014, we had installed solar energy systems for 232,710 customers and 124,021 customers, respectively.

Energy Contracts

We define an energy contract as a residential, commercial or government lease, power purchase agreement or MyPower contract pursuant to which consumers use or will use energy generated by a solar energy system that we have installed or have been contracted to install. For landlord-tenant structures in which we contract with the landlord or development company, we include each residence as an individual contract. For commercial customers with multiple locations, each location is deemed a contract if we maintain a separate contract for that location. We track the cumulative number of energy contracts as of the end of a given period as an indicator of our historical growth and as an indicator of our rate of growth from period to period.

The following table sets forth our cumulative number of energy contracts as of the dates presented:

	December 31, 2015	December 31, 2014
Cumulative energy contracts	322,897	177,455

Megawatts Deployed and Megawatts Installed

We track megawatts deployed, or the megawatt production capacity of our solar energy systems that have had all required building department inspections completed during the applicable period. This metric includes solar energy systems deployed under energy contracts, as well as solar energy system direct sales. Because the size of our solar energy systems varies greatly, we believe that tracking the megawatt production capacity of deployed systems is an indicator of our growth rate and cost efficiency of our solar energy system business. We track the megawatts deployed in a given period as an indicator of asset growth and efficiency of the scale of our operations in the period. We track cumulative megawatts deployed as of the end of a given period as an indicator of our historical growth and our future opportunity to provide customers with additional solutions to further lower their energy costs.

The following table sets forth the megawatt production capacity of solar energy systems that we have deployed during the periods presented and the cumulative megawatts deployed as of the end of each period presented:

	Year Ended December 31,		
	2015	2014	2013
Megawatts deployed	778	502	280
Cumulative megawatts deployed	1,847	1,069	567

In addition, we track megawatts installed, or the megawatt production capacity of solar energy systems for which (i) all solar panels, inverters, mounting and racking hardware and system wiring have been installed, (ii) the system inverter is connected and a successful direct current string test has been completed confirming the production capacity of the system and (iii) the system is capable of being grid connected (including pending a utility disconnect procedure), in each case, as of the latest of which criteria is completed during the applicable period. This metric includes solar energy systems installed under energy contracts, as well as solar energy system direct sales. The following table sets forth the megawatt production capacity of solar energy systems that we have installed during the periods presented and the cumulative megawatts installed as of the end of each period presented:

	Year Ended December 31,		
	2015	2014	2013
Megawatts installed	870	503	285
Cumulative megawatts installed	1,945	1,075	572

Though we have historically reported nominal contracted payments as a representation of the growth in our operations and the value of our energy contracts, we have decided not to report our undeployed backlog of contracts as a value in this manner and will no longer be reporting this amount.

Components of Results of Operations

Revenue

Operating leases and solar energy systems incentives. We classify and account for our leases and power purchase agreements as operating leases. We consider the proceeds from solar energy system incentives offered by certain state and local governments to form part of the proceeds from our operating leases. We recognize revenue from our operating leases over the operating lease term either on a straight-line basis over the lease term for lease arrangements or as we generate and sell energy to customers under power purchase agreements. We typically bundle and charge for remote monitoring services as part of the lease or power purchase agreement and recognize the allocated amount as revenue over the term of the monitoring service. The term of our leases and power purchase agreements ranges between 10 and 20 years.

Solar energy systems and components sales. Solar energy systems and components sales is comprised of revenue from the outright sale of solar energy systems directly to cash paying customers, revenue generated from long-term solar energy system sales contracts, revenue from solar energy systems financed under MyPower contracts, revenue generated from fulfillment of orders of Zep Solar and Silevo products that were outstanding on the acquisitions of Zep Solar and Silevo and revenue attributable to our energy-related products and services. We generally recognize revenue from solar energy systems sold outright to our customers when we install the solar energy system and it passes inspection by the utility or the authority having jurisdiction. We allocate a portion of the proceeds from the sale of the system to the remote monitoring service or maintenance service if applicable and recognize the allocated amount (based on relative selling prices) as revenue over the contractual service term. We recognize revenue generated from long-term solar energy system sales contracts on a percentage-of-completion basis, based on the ratio of labor costs incurred to date to total project labor costs. We recognize revenue from solar energy systems financed under MyPower over the 30-year term of the contract as the customer pays the loan's principal and interest. We generally recognize revenue from sales of Zep Solar or Silevo components upon delivery to the third-party customer. Currently, we are internally consuming the entire output of Zep Solar products in solar energy systems installations for our customers. We recognize revenue from our energy-related products and services when we complete the services or the customer referral.

During the years ended December 31, 2015 and 2014, less than 10% of our solar energy system installations were cash sales, as measured by system capacities. However, because of our revenue recognition policy, these sales represented 19% and 32%, respectively, of our total revenue for those periods. We expect installations utilizing leases and power purchase agreements to continue to represent a significant portion of our installed systems. We also expect financed sales to grow and form a significant portion of our future installations. As a result, the number of systems sold outright and delivered in a given period has a disproportionate effect on the total revenue reported for that period.

Cost of Revenue, Gross Profit and Gross Profit Margin

Operating Leases and Solar Energy Systems Incentives Cost of Revenue. Operating leases and solar energy systems incentives cost of revenue is primarily comprised of depreciation of the cost of leased solar energy systems reduced by amortization of U.S. Treasury grants income, maintenance costs associated with those systems and amortization of initial direct costs associated with those systems. Initial direct costs include allocated incremental contract administration costs, sales commissions and customer acquisition referral fees from the origination of solar energy systems leased to customers. These contract administration costs include incremental personnel costs, such as salary, bonus, employee benefit costs and stock-based compensation costs. Operating leases and solar energy systems incentives cost of revenue also includes direct and allocated costs associated with monitoring services for these systems.

Solar Energy Systems and Components Sales Cost of Revenue. The substantial majority of solar energy systems and components sales cost of revenue consists of the costs of solar energy systems components and personnel costs associated with system installations or manufacture of components. Cost of revenue associated with solar energy systems financed under MyPower is comprised of a portion of the cost of the systems, which is generally recognized in proportion to the revenue recognized, and the estimated warranty costs associated with the systems, which are fully recognized upon the delivery of the systems and result in a gross loss being recognized upon the delivery of the systems. We acquire the significant component parts of the solar energy systems directly from foreign and domestic manufacturers or distributors. Following the acquisition of Zep Solar, we produce, through contract manufacturers, mounting solutions for photovoltaic panels, which are components of the solar energy systems. In the fourth quarter of 2015, following the acquisition of Silevo, we began limited domestic production of solar cells and modules for use in our solar energy systems installations. We primarily consume both Zep Solar and Silevo products.

Solar energy systems and components sales cost of revenue also includes solar energy system installation costs, project-specific engineering and design costs, estimated warranty costs, freight charges, allocated corporate overhead costs such as facilities costs, vehicle depreciation costs and personnel costs associated with supply chain, logistics, operations management, safety and quality control. Personnel costs include salary, bonus, employee benefit costs and stock-based compensation costs. Our employees install our residential solar energy systems, and our project managers and construction managers oversee the subcontractors that install our commercial systems. To a lesser extent, solar energy systems and components sales cost of revenue also includes personnel costs associated with performing our energy-related products and services and related materials.

We allocate to solar energy systems and components sales cost of revenue certain corporate overhead costs that include rental and operating costs for our corporate facilities, information technology costs, travel expenses and certain professional services to cost of solar energy systems, work in process, cost of sales, sales and marketing and general and administrative expenses using an appropriate allocation basis.

Sales and Marketing Expenses

Sales and marketing expenses include personnel costs such as salaries, benefits, bonuses, sales commissions and stock-based compensation as well as advertising, promotional and other marketing related expenses. Sales and marketing expenses also include certain customer referral fees that are not a component of initial direct costs, allocated corporate overhead costs related to facilities and information technology, travel and professional services. Initial direct costs from the origination of solar energy systems leased to customers (which include the incremental cost of contract administration, referral fees and sales commissions) are capitalized as an element of solar energy systems, leased and to be leased, and subsequently amortized over the term of the related lease or power purchase agreement as a component of operating leases and solar energy systems incentives cost of revenue. We expect sales and marketing costs to increase in future periods for us to meet our installation and deployment targets.

General and Administrative Expenses

General and administrative expenses include personnel costs such as salaries, bonuses and stock-based compensation and professional fees related to legal, human resources, accounting and structured finance services. General and administrative expenses also include allocated corporate overhead costs related to facilities, information technology, asset management, travel and professional services. We anticipate that we will continue to incur additional administrative headcount costs to support the growth in our business and our financing fund arrangements.

Research and Development Expenses

Research and development expenses include personnel costs such as salaries, benefits, bonuses and stock-based compensation. Research and development expenses also include allocated corporate overhead costs related to facilities and information technology, travel and professional services. We expect research and development expenses to increase significantly in future periods as we continue to grow our research and development group headcount and undertake more research projects.

Interest Income and Expense

Interest income and expense primarily consist of the interest charges associated with our revolving credit facilities, long-term debt facilities, solar asset-backed notes, convertible notes, Solar Bonds, financing obligations and capital lease obligations. Our secured revolving credit facilities, certain of our long-term debt facilities and certain of our Solar Bonds are subject to variable interest rates. The interest rates charged on our solar asset-backed notes, our convertible notes and certain of our Solar Bonds are fixed at inception. The interest rates charged on our financing obligations are fixed at the inception of the related transaction based on the incremental borrowing rate in effect on such date or the effective interest rate in the arrangement giving rise to the obligation. The interest rates charged on our capital lease obligations are fixed at the inception of the related transaction based on the incremental borrowing rate in effect on such date. Interest income and expense also include the amortization of any debt discounts, partially offset by a nominal amount of interest income generated from our cash holdings in interest-bearing accounts.

Other Income and Expenses

Our other income and expenses consisted principally of franchise taxes, losses on the extinguishment of long-term debt, the change in fair value of interest rate swaps and accretion on the contingent consideration related to the Silevo acquisition. We will continue to accrete the contingent consideration until it is settled or determined to be not payable.

Provision for Income Taxes

We are subject to taxation mainly in the United States, Puerto Rico, China, United Kingdom, Mexico and Canada. We conduct our business primarily in the United States.

Our effective tax rates differ from the statutory rate primarily due to the valuation allowance on our deferred taxes, state taxes, foreign taxes, intercompany and joint venture transactions and nondeductible stock-based compensation. Our current tax expense is primarily comprised of the amortization of prepaid tax expense arising from sales of assets to joint venture funds included in our consolidated financial statements and foreign income taxes. In the years ended December 31, 2014 and 2013, as a result of the acquisitions of Silevo and Zep Solar, for which a significant amount of the purchase price allocated to intangible assets had no tax basis, we recorded a net long-term deferred tax liability, which subsequently triggered the release of $27.3 million and $24.8 million, respectively, of the valuation allowance on our deferred tax asset as a benefit to income taxes.

As of December 31, 2015 and 2014, we had a net deferred tax asset of $367.8 million and $111.2 million, respectively . During these periods, we maintained a valuation allowance against the net deferred tax asset. As of December 31, 2015, as a result of increased sales to the joint venture funds and increased sales under the MyPower program, we had utilized all available net operating loss carryovers and investment tax credits to reduce our current tax liability, and we had a remaining current tax liability of $43.3 million for Federal, state and foreign jurisdictions. We expect to have a higher current tax liability in future periods after utilizing all available net operating loss carryovers and investment tax credits in the current period.

Net Income (Loss) Attributable to Stockholders

We determine the net income (loss) attributable to stockholders by deducting from net income (loss) in a period the net income (loss) attributable to noncontrolling interests and redeemable noncontrolling interests. The net income (loss) attributable to noncontrolling interests and redeemable noncontrolling interests represents the joint venture fund investors' allocable share in the results of the joint venture funds and three investors' allocable share in the results of a limited partnership operated by one of our acquired subsidiaries in China. We have determined that the provisions in the contractual arrangements represent substantive profit sharing arrangements. We have further determined that the appropriate methodology for calculating the noncontrolling interest and redeemable noncontrolling interests balances that reflects the substantive profit sharing arrangements is a balance sheet approach using the hypothetical liquidation at book value method, or HLBV method, for the joint venture funds. We therefore use the HLBV method to determine the share of the results of the joint venture funds attributable to the joint venture fund investors, which we record in our consolidated balance sheets as noncontrolling interests and redeemable noncontrolling interests in subsidiaries. The HLBV method determines the joint venture fund investors' allocable share of the results of the joint venture funds by calculating the net change in the joint venture fund investors' share in the consolidated net assets of the joint venture funds at the beginning

and end of the period after adjusting for any transactions between the joint venture funds and the joint venture fund investors, such as capital contributions or cash distributions. However, in all cases, the redeemable noncontrolling interests balance is at least equal to the redemption amount.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in conformity with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and the accompanying notes. We base our estimates on historical experience and on various other assumptions believed to be reasonable. Actual results could differ materially from these estimates. Our future consolidated financial statements will be affected to the extent that our actual results differ materially from these estimates.

We believe that the estimates and assumptions regarding the selling price of undelivered elements for revenue recognition purposes, the collectability of accounts and rebates receivable, the valuation of inventories, the labor costs for long-term contracts used as a basis for determining the percentage of completion for such contracts, the fair values and residual values of solar energy systems subject to leases, the accounting for business combinations, the fair values and useful lives of acquired tangible and intangible assets, the fair value of debt assumed under business combinations, the fair value of contingent consideration payable under business combinations, the fair value of short-term investments, the useful lives of solar energy systems, property, plant and equipment, the determination of accrued warranty, the determination of accrued liability for solar energy system performance guarantees, the determination of lease pass-through financing obligations, the discount rates used to determine the fair values of ITCs, the valuation of stock-based compensation, the determination of valuation allowances associated with deferred tax assets, asset impairment, the valuation of build-to-suit lease assets, the fair value of interest rate swaps and other items have the greatest potential impact on our consolidated financial statements. Therefore, we consider these to be our critical accounting policies and estimates. For further information on all of our significant policies, see Note 2, *Summary of Significant Accounting Policies and Procedures*, to our consolidated financial statements included elsewhere in this annual report on Form 10-K.

Principles of Consolidation

Our consolidated financial statements reflect our accounts and operations and those of our subsidiaries in which we have a controlling financial interest. In accordance with the provisions of Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, 810, *Consolidation*, we consolidate any variable interest entity, or VIE, of which we are the primary beneficiary. We form VIEs with our financing fund investors in the ordinary course of business in order to facilitate the funding and monetization of certain attributes associated with our solar energy systems. The typical condition for a controlling financial interest ownership is holding a majority of the voting interests of an entity; however, a controlling financial interest may also exist in entities, such as VIEs, through arrangements that do not involve controlling voting interests. ASC 810 requires a variable interest holder to consolidate a VIE if that party has the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. This holder is considered the primary beneficiary. We do not consolidate a VIE in which we have a majority ownership interest when we are not considered the primary beneficiary. We have determined that we are the primary beneficiary of a number of our VIEs, and accordingly, we consolidate the assets and liabilities of such VIEs. We evaluate our relationships with our VIEs on an ongoing basis to ensure that we continue to be the primary beneficiary. All intercompany transactions and balances have been eliminated in consolidation.

Revenue Recognition

Our customers purchase solar energy systems from us under fixed-price contracts or lease our solar energy systems that also include remote monitoring services. A residential customer that purchases a solar energy system has the option to pay the full purchase price for the system at the time of purchase or finance the purchase through a 30-year loan from our wholly owned subsidiary under the MyPower program that we launched in the fourth quarter of 2014. We can also earn incentives that have been assigned to us by our customers, where available from utility companies and state and local governments.

Solar Energy Systems and Components Sales

For solar energy systems and components sales wherein customers pay the full purchase price upon delivery of the system, we recognize revenue, net of any applicable governmental sales taxes, in accordance with ASC 605-25, *Revenue Recognition—Multiple-Element Arrangements*, and ASC 605-10-S99, *Revenue Recognition—Overall—SEC Materials*. Revenue is recognized when (1) persuasive evidence of an arrangement exists, (2) delivery has occurred or services have been rendered, (3) the sales price is fixed or determinable and (4) collection of the related receivable is reasonably assured. Components comprise of photovoltaic panels and solar energy system mounting hardware. In instances where there are multiple deliverables in a single arrangement, we allocate the arrangement consideration to the various elements in the arrangement based on the relative selling price method. We recognize revenue when we install a solar energy system and it passes inspection by the utility or the authority having jurisdiction, provided all other revenue recognition criteria have been met. Costs incurred on residential installations before the solar energy systems are completed are included in inventories as work in progress in our consolidated balance sheets.

We recognize revenue for solar energy systems constructed for certain commercial customers according to ASC 605-35, *Revenue Recognition—Construction-Type and Production Type Contracts*. Revenue is recognized on a percentage-of-completion basis, based on the ratio of labor costs incurred to date to total projected labor costs. Provisions are made for the full amount of any anticipated losses on a contract-by-contract basis. Costs in excess of billings are recorded where costs recognized are in excess of amounts billed to customers of purchased commercial solar energy systems.

For solar energy systems sold under a MyPower contract, we have determined that the arrangement consideration is not currently fixed or determinable. In making this determination, we considered that (i) the MyPower arrangement is unique and we do not have company-specific or market history for similar financing arrangements with similar asset classes over an extended term; (ii) customer preferences and satisfaction during the life of these long-term contracts, including as a result of technological advances in solar energy systems over time, may change, and we may be incented to offer future inducements or concessions to ensure customers remain satisfied during the life of these long-term contracts; and (iii) possible future decreases in the retail prices of electricity from utilities or from other renewable energy sources that may make the purchase of the solar energy systems less economically attractive and may cause us to amend the terms of our contracts to ensure continued performance and to remain competitive. Accordingly, we initially defer the revenue associated with the sale of a solar energy system under a MyPower contract when we deliver a system that has passed inspection by the utility or the authority having jurisdiction. In instances where there are multiple deliverables in a single MyPower contract, we allocate the arrangement consideration to the various elements in the contract based on the relative selling price method. We subsequently recognize revenue for the system over the term of the contract as cash payments are received for the loan's outstanding principal and interest. The deferred revenue is included in our consolidated balance sheets under current portion of deferred revenue for the portion expected to be recognized as revenue in the next 12 months, and the non-current portion is included under deferred revenue, net of current portion. We record a note receivable when the customer secures the loan from our wholly owned subsidiary to finance the purchase of the solar energy system.

The costs associated with solar energy systems sold under MyPower contracts, including the costs of acquisition of system components, personnel costs associated with system installations and costs to originate the contracts such as sales commissions, referral fees and some incremental contract administration costs, are initially capitalized as deferred costs. Subsequently, these costs are recognized as a component of cost of revenue from solar energy systems and components sales for the costs associated with system components and installations, or as a component of operating expenses for costs associated with contract origination, generally in proportion to the reduction of the MyPower loans' outstanding principal over the 30-year term. The deferred costs are included in our consolidated balance sheets under prepaid expenses and other current assets for the portion expected to be recognized in our consolidated statements of operations in the next 12 months, and the non-current portion is included as a component of other assets. However, the estimated warranty costs associated with the systems are fully expensed upon the delivery of the systems and result in a gross loss being recognized upon the delivery of the systems.

Operating Leases and Power Purchase Agreements

We are the lessor under lease agreements for solar energy systems, which are accounted for as operating leases in accordance with ASC 840, *Leases*. We record operating lease revenue from minimum lease payments, including upfront rebates and incentives earned from such systems, on a straight-line basis over the life of the lease term, assuming all other

revenue recognition criteria are met. For incentives that are earned based on the amount of electricity generated by the system, we record revenue as the amounts are earned. The difference between the payments received and the revenue recognized is recorded as deferred revenue on the consolidated balance sheet.

For solar energy systems where customers purchase electricity from us under power purchase agreements, we have determined that these agreements should be accounted for, in substance, as operating leases pursuant to ASC 840. We recognize revenue based upon the amount of electricity delivered at rates specified under the contracts, assuming all other revenue recognition criteria are met.

We capitalize initial direct costs from the origination of solar energy systems leased to customers (the incremental cost of contract administration, referral fees and sales commissions) as an element of solar energy systems, leased and to be leased – net, and subsequently amortize these costs over the term of the related lease or power purchase agreement, which generally ranges from 10 to 20 years.

Remote Monitoring Services

We provide solar energy system remote monitoring services, which are generally bundled with both sales and leases of solar energy systems. We allocate revenue between remote monitoring services and the other elements in a bundled sale of a solar energy system using the relative selling price method. The selling prices used in the allocation are determined by reference to the prices charged by third-parties for similar services and products on a standalone basis. For remote monitoring services bundled with a sale of a solar energy system, we recognize the revenue allocated to remote monitoring services over the term specified in the associated contract or over the warranty period of the solar energy system if the contract does not specify the term. For remote monitoring services bundled with a lease of a solar energy system, we recognize the revenue allocated to remote monitoring services on a straight-line basis over the lease term. To date, remote monitoring services revenue has not been material and is included in our consolidated statements of operations under both operating leases and solar energy systems incentives revenue, when remote monitoring services are bundled with leases of solar energy systems, and solar energy systems and components sales revenue, when remote monitoring services are bundled with sales of solar energy systems.

Sale-Leaseback

We are a party to master lease agreements that provide for the sale of solar energy systems to third-parties and the simultaneous leaseback of the systems, which we then sublease to our customers. In sale-leaseback arrangements, we first determine whether the solar energy system under the sale-leaseback arrangement is "integral equipment." A solar energy system is determined to be integral equipment when the cost to remove the system from its existing location, including the shipping and reinstallation costs of the solar energy system at the new site, including any diminution in fair value, exceeds 10% of the fair value of the solar energy system at the time of its original installation. When the leaseback arrangements expire, we have the option to purchase the solar energy system, and in most cases, the lessor has the option to sell the system back to us, though in some instances, the lessor can only sell the system back to us prior to expiration of the arrangement.

For solar energy systems that we have determined to be integral equipment, we have concluded that these rights create a continuing involvement. Therefore, we use the financing method to account for the sale-leaseback of such solar energy systems. Under the financing method, we do not recognize as revenue any of the sale proceeds received from the lessor that contractually constitutes a payment to acquire the solar energy system. Instead, we treat any such sale proceeds received as financing capital to install and deliver the solar energy system and, accordingly, record the proceeds as a sale-leaseback financing obligation in our consolidated balance sheets. We allocate the leaseback payments made to the lessor between interest expense and a reduction to the sale-leaseback financing obligation. Interest on the financing obligation is calculated using our incremental borrowing rate at the inception of the arrangement on the outstanding financing obligation. We determine our incremental borrowing rate by reference to the interest rates that we would obtain in the financial markets to borrow amounts equal to the sale-leaseback financing obligation over a term similar to the master lease term.

For solar energy systems that we have determined not to be integral equipment, we determine if the leaseback is classified as a capital lease or an operating lease. For leasebacks classified as capital leases, we initially record a capital lease asset and capital lease obligation in our consolidated balance sheet equal to the lower of the present value of our future minimum leaseback payments or the fair value of the solar energy system. For capital leasebacks, we do not recognize any revenue but defer the gross profit comprising of the net of the revenue and the associated cost of sale. For leasebacks classified as operating leases, we recognize a portion of the revenue and the associated cost of sale and defer the portion of revenue and cost of sale that represents the gross profit that is equal to the present value of the future minimum lease payments over the master leaseback term. For both capital and operating leasebacks, we record the deferred gross profit in our consolidated balance sheet as deferred income and amortize the deferred income over the leaseback term as a reduction to the leaseback rental expense included in operating leases and solar energy systems incentives cost of revenue in our consolidated statement of operations.

Solar Energy Systems, Leased and To Be Leased

We are the operating lessor of the solar energy systems under leases that qualify as operating leases. We account for the leases in accordance with ASC 840. To determine lease classification, we evaluate lease terms to determine whether there is a transfer of ownership or bargain purchase option at the end of the lease, whether the lease term is greater than 75% of the useful life, or whether the present value of minimum lease payments exceed 90% of the fair value at lease inception. We utilize periodic appraisals to estimate useful life and fair values at lease inception, and residual values at lease termination. Solar energy systems are stated at cost, less accumulated depreciation.

Depreciation and amortization is calculated using the straight-line method over the estimated useful lives of the respective assets as follows:

	Useful Lives
Solar energy systems leased to customers	30 years
Initial direct costs related to customer solar energy system lease acquisition costs	Lease term (10 to 20 years)

Solar energy systems held for lease to customers are installed systems pending interconnection with the respective utility companies and will be depreciated as solar energy systems leased to customers when the respective systems have been interconnected and placed in service.

Solar energy systems under construction represents systems that are under installation, which will be depreciated as solar energy systems leased to customers when the respective systems are completed, interconnected and subsequently leased to customers.

Initial direct costs related to customer solar energy system lease acquisition costs are capitalized and amortized over the term of the related customer lease agreements.

Presentation of Cash Flows Associated with Solar Energy Systems

We classify cash flows associated with solar energy systems in accordance with ASC 230, *Statement of Cash Flows.* We determine the appropriate classification of cash payments related to solar energy systems depending on the activity that is likely to be the predominant source of cash flows for the item being paid for. Accordingly, we present payments made in a period for costs incurred to install solar energy systems that will be leased to customers, including the payments for cost of the inventory that is utilized in such systems, as investing activities in our consolidated statement of cash flows. Payments made for inventory that will be utilized for solar energy systems that will be sold to customers are presented as cash flows from operations in our consolidated statement of cash flows. We do not track payments for component parts at the individual component part level as they are not unique and can be used in either leased solar energy systems or solar energy systems that are sold to customers. Accordingly, we treat costs of raw materials transferred to solar energy systems to be leased as if they were paid in the period they are transferred to the systems.

Warranties

We generally provide a warranty on the installation and components of the solar energy systems we sell, including sales under MyPower contracts, for periods typically between 10 to 30 years. The manufacturer's warranty on the solar energy systems' components, which is typically passed-through to customers, ranges from one to 25 years. However, for the solar energy systems under lease contracts or power purchase agreements, we do not accrue a warranty liability because those systems are owned by subsidiaries that we consolidate. Instead, any repair costs on those systems are expensed when they are incurred as a component of operating leases and solar energy systems incentives cost of revenue.

Solar Energy Systems Performance Guarantees

We guarantee certain specified minimum solar energy production output for certain systems leased or sold to customers generally for a term of up to 30 years. We monitor the solar energy systems to ensure that these outputs are being achieved. We evaluate if any amounts are due to our customers and make any payments periodically as specified in the customer contracts. If we determine that the guaranteed minimum solar energy production output has not been

achieved, then we record a liability for the estimated amounts payable as a component of accrued and other current liabilities. Since the actual solar energy production output is impacted by seasonality, this liability is also affected by seasonality.

Deferred U.S. Treasury Grants Income

We are eligible for U.S. Treasury grants received or receivable on eligible property as defined under Section 1603 of the American Recovery and Reinvestment Act of 2009, as amended by the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of December 2010, which includes solar energy system installations, upon approval by the U.S. Treasury Department. However, to be eligible for U.S. Treasury grants, a solar energy system must have commenced construction in 2011 either physically or through the incurrence of sufficient project costs. We submit applications for grants receivable from the U.S. Treasury Department related to eligible property based on 30% of the tax basis of the solar energy systems as supported by independently appraised fair market values of the systems or guideline system values that have been posted by the U.S. Treasury Department on its website. To determine the fair market value of the systems, an independent appraiser considers various factors such as the cost of producing the systems, the estimated price that could be obtained in the market from the sale of the systems and the present value of the economic benefits expected to be generated by the systems. We then present our appraised fair market value to the U.S. Treasury Department when we apply for grants on our solar energy systems. In a number of cases, the U.S. Treasury Department has determined that grants should be paid based on a lower value for the systems and has in such instances posted guideline system values on its website that should be used in the grant applications.

We initially record the grants receivable for leased solar energy systems as deferred income at the amounts that have been approved for payment by the U.S. Treasury Department and then amortize them on a straight-line basis over the estimated useful lives of the related solar energy systems of 30 years. The amortization of the deferred income is recorded as a reduction to depreciation expense, which is a component of the cost of revenue of operating leases and solar energy systems incentives in our consolidated statements of operations. A catch-up adjustment is recorded in the period in which the grant is approved by the U.S. Treasury Department or received by lease pass-through investors to recognize the portion of the grant that matches proportionally the amortization for the period between the date of placement in service of the solar energy systems and approval by the U.S. Treasury Department or receipt by lease pass-through investors of the associated grant, in the case of lease pass-through fund arrangements. Some of our fund agreements obligate us to reimburse the fund investors based upon the difference between their anticipated benefit from U.S. Treasury grants at the formation of the funds and the benefit they receive from the amounts paid by the U.S. Treasury Department. For the joint venture financing funds where we are contractually obligated to reimburse investors for reductions in anticipated grants receivable, we record amounts we expect to pay the investors as distributions payable to noncontrolling interests and redeemable noncontrolling interests in our consolidated balance sheets, and any impact to our consolidated statements of operations, which is determined using the HLBV method, is reflected in the net income or loss attributable to noncontrolling interests and redeemable noncontrolling interests line item. For sale-leaseback financing funds where we are contractually obligated to reimburse investors for reductions in anticipated grants receivable, we record amounts we expect to pay the investors under accrued and other current liabilities and reduce the deferred gain on sale-leaseback transactions included within other liabilities in our consolidated balance sheets, with no impact on our consolidated statements of operations. For solar energy systems under lease pass-through fund arrangements, all amounts received from the investors are recorded in our consolidated balance sheets as a lease pass-through financing obligation, and the amounts we expect to reimburse investors for reductions in anticipated grants receivable would reduce the lease pass-through financing obligation with no impact on our consolidated statements of operations. We reduce the lease pass-through financing obligation and record deferred income for the U.S. Treasury grants that are paid directly to the investors upon receipt of the grants by the investors.

Deferred ITCs Revenue

Our solar energy systems are eligible for ITCs that accrue to eligible property under the IRC. Under Section 50(d)(5) of the IRC and the related regulations, a lessor of qualifying property may elect to treat the lessee as the owner of such property for the purposes of claiming the ITCs associated with such property. These regulations enable the ITCs to be separated from the ownership of the property and allow the transfer of the ITCs. Under the lease pass-through fund arrangements, we can make a tax election to pass-through the ITCs to the investor, who is the legal lessee of the property. We are therefore able to monetize these ITCs to investors who can utilize them in return for cash payments. We consider the monetization of ITCs to constitute one of the key elements of realizing the value associated with solar energy systems. We therefore view the proceeds from the monetization of ITCs to be a component of revenue generated from solar energy systems.

For the lease pass-through fund arrangements, we allocate a portion of the aggregate payments received from the investors to the estimated fair value of the assigned ITCs and the balance to the future customer lease payments that are

also assigned to the investors. The estimated fair value of the ITCs is determined by discounting the estimated cash flows impacts of the ITCs using an appropriate discount rate that reflects a market interest rate.

We recognize the revenue associated with the monetization of ITCs in accordance with ASC 605-10-S99. The revenue associated with the monetization of the ITCs is recognized when (1) persuasive evidence of an arrangement exists, (2) delivery has occurred or services have been rendered, (3) the sales price is fixed or determinable and (4) collection of the related receivable is reasonably assured. The ITCs are subject to recapture under the IRC if the underlying solar energy system either ceases to be a qualifying property or undergoes a change in ownership within five years of its placed in service date. The recapture amount decreases on the anniversary of the placed in service date. As we have an obligation to ensure the solar energy system is in service and operational for a term of five years to avoid any recapture of the ITCs, we recognize revenue as the recapture provisions lapse assuming the other aforementioned revenue recognition criteria have been met. The monetized ITCs are initially recorded as deferred revenue on our consolidated balance sheets, and subsequently, one-fifth of the monetized ITCs is recognized as revenue from operating leases and solar energy systems incentives in our consolidated statements of operations on each anniversary of the solar energy system's placed in service date over the next five years.

We guarantee our financing fund investors that in the event of a subsequent recapture of ITCs by the taxing authority due to our noncompliance with the applicable ITC guidelines, we would compensate them for any recaptured ITCs. We have concluded that the likelihood of a recapture event is remote and, consequently, have not recorded any liability in our consolidated balance sheets for any potential recapture exposure.

Stock-Based Compensation

We account for stock-based compensation costs under the provisions of ASC 718, *Compensation—Stock Compensation*, which requires the measurement and recognition of compensation expense related to the fair value of stock-based compensation awards that are ultimately expected to vest. Stock-based compensation expense recognized includes the compensation cost for all stock-based payments granted to employees based on the grant date fair value estimated in accordance with the provisions of ASC 718. ASC 718 is also applied to awards modified, repurchased or cancelled during the periods reported.

We apply ASC 718 and ASC Subtopic 505-50, *Equity-Based Payments to Non Employees*, to options and other stock-based awards issued to non-employees. In accordance with ASC 718 and ASC Subtopic 505-50, we use the Black-Scholes option-pricing model to measure the fair value of the options at the measurement date. The measurement of stock-based compensation is subject to periodic adjustments as the awards vest and the resulting change in fair value is recognized in our consolidated statements of operations in the period the related services are rendered.

Determining the fair value of stock-based awards at the grant date requires judgment. We use the Black-Scholes option valuation model, except for awards with market conditions for which we use a Monte Carlo simulation, to determine the fair value of stock options. The determination of the grant date fair value of stock options using an option valuation model is affected by our estimated common stock fair value as well as assumptions regarding a number of other complex and subjective variables. These variables include our expected stock price volatility over the expected term, stock option exercise and cancellation behaviors, risk-free interest rates and expected dividends, which are estimated as follows:

- *Fair value of our common stock.* Because our common stock was not publicly traded when we issued stock options prior to our initial public offering, we estimated our common stock's fair value as discussed below. Subsequent to our initial public offering, we determined the fair value of our common stock based on its trading price on the NASDAQ Global Select Market.
- *Expected term.* The expected term represents the period that our stock-based awards are expected to be outstanding and was primarily determined using the simplified method in accordance with guidance provided by the U.S. Securities and Exchange Commission, or SEC. The simplified method calculates the expected term as the average of the time-to-vesting and the contractual life of the awards. We will continue to utilize the simplified method until we have established a reasonable period of representative trading history as a public company, at which time we will determine the expected term based on the historical option exercise behavior of our employees, expectations about future option exercise behavior and post-vesting cancellations.

- *Volatility.* Because we do not have a significant trading history for our common stock, the expected stock price volatility for our common stock has been estimated based on the average historical volatilities of us and our industry peers using daily price observations over a period equivalent to the expected term of the stock option grants. Industry peers consist of several public companies in the solar energy industry similar in size and financial leverage. We did not rely on implied volatilities of traded options in our industry peers' common stock because the volume of activity was relatively low. We intend to continue to consistently apply this process using the same or similar public companies until a sufficient amount of historical information regarding the volatility of our own common stock share price becomes available, or unless circumstances change such that the identified companies are no longer similar to us. If this occurs, more suitable companies whose share prices are publicly available would be utilized in the calculation. Higher volatility and longer expected lives would result in an increase to stock-based compensation expense determined on the grant date.
- *Risk-free rate.* The risk-free interest rate is based on the yields of U.S. Treasury securities with maturities similar to the expected term of the options for each option group.
- *Dividend yield.* We have never declared or paid any cash dividends and do not presently plan to pay cash dividends in the foreseeable future. Consequently, we used an expected dividend yield of zero.

In addition to assumptions used in the Black-Scholes option valuation model, we must also estimate a forfeiture rate to calculate the stock-based compensation for our awards. Our forfeiture rate is based on an analysis of our actual forfeitures, and forecasted forfeitures for awards with performance conditions. We routinely evaluate the appropriateness of the forfeiture rate based on actual and forecasted forfeiture experience, analysis of employee turnover and expectations of future option exercise behavior. Any changes in the estimated forfeiture rate can have a significant impact on our stock-based compensation expense as the cumulative effect of adjusting the forfeiture rate is recognized in the period the forfeiture estimate is changed. If a revised forfeiture rate is higher than the previously estimated forfeiture rate, an adjustment is made that would result in a decrease to the stock-based compensation expense recognized in our consolidated financial statements. If a revised forfeiture rate is lower than the previously estimated forfeiture rate, an adjustment is made that would result in an increase to the stock-based compensation expense recognized in our consolidated financial statements.

We will continue to use judgment in evaluating the expected term, expected volatility and forfeiture rate related to our stock-based compensation on a prospective basis, as well as the likelihood of achieving performance-based vesting criteria. As we continue to accumulate additional data related to our common stock and operations, we may have refinements to the estimates of our expected volatility, expected terms, forfeiture rates and likelihood of achieving performance-based vesting criteria, which could materially impact our future stock-based compensation expense as it relates to the future grants of our stock-based awards.

Short-Term Investments

Our short-term investments are comprised of corporate debt securities and asset-backed securities. We classify short-term investments as available-for-sale and carry them at fair value, with any unrealized gains or losses recognized as other comprehensive income or loss in our consolidated balance sheet. The specific identification method is used to determine the cost of any securities disposed of, with any realized gains or losses recognized as other income or expense in our consolidated statement of operations. Short-term investments are anticipated to be used for current operations and are, therefore, classified as current assets even though their maturities may extend beyond one year. We periodically review short-term investments for impairment. In the event a decline in value is determined to be other-than-temporary, an impairment loss is recognized. When determining if a decline in value is other-than-temporary, we take into consideration the current market conditions and the duration and severity of and the reason for the decline, as well as the likelihood that we would need to sell the security prior to a recovery of par value.

Inventories

Inventories include raw materials that include silicon wafers, process gasses, chemicals and other consumables used in solar cell production, solar cells, photovoltaic panels, inverters, mounting hardware and miscellaneous electrical components. Inventories also include work in process that includes raw materials partially installed and direct and indirect capitalized installation costs. Raw materials and work in process are stated at the lower of cost or market (on a first-in-first-out basis). Work in process primarily relates to solar energy systems that will be sold to customers, which are under construction and have yet to pass inspection.

We also evaluate our inventory reserves on a quarterly basis and write down the value of inventories for estimated excess and obsolete inventories based upon assumptions about future demand and market conditions.

Business Combinations

We account for business acquisitions under ASC 805, *Business Combinations*. The cost of an acquisition is measured at the fair value of the assets given, equity instruments issued, contingent consideration issuable and liabilities assumed at the acquisition date. Costs that are directly attributable to the acquisition are expensed as incurred. Identifiable assets, including intangible assets, acquired and liabilities, including contingent liabilities, assumed in the acquisition are measured initially at their fair values at the acquisition date. Any noncontrolling interests in the acquired business are also initially measured at fair value. We recognize goodwill if the aggregate fair value of the total purchase consideration and the noncontrolling interests is in excess of the aggregate fair value of the identifiable assets acquired and the liabilities assumed.

Long-Lived Assets

Our long-lived assets include property, plant and equipment, solar energy systems, leased and to be leased, and intangible assets acquired through business combinations. Intangible assets with definite useful lives are amortized over their estimated useful lives, which range from one to 30 years.

Furthermore, we are deemed to be the owner, for accounting purposes, during the construction phase of certain long-lived assets under build-to-suit lease arrangements because of our involvement with the construction, our exposure to any potential cost overruns and our other commitments under the arrangements. In these cases, we recognize a build-to-suit lease asset under construction and a corresponding build-to-suit lease liability on our consolidated balance sheets.

In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of a long-lived asset, or group of assets, as appropriate, may not be recoverable. If the aggregate undiscounted future net cash flows expected to result from the use and the eventual disposition of a long-lived asset is less than its carrying value, then we would recognize an impairment loss based on the discounted future net cash flows.

Goodwill

Goodwill represents the difference between the purchase price and the aggregate fair value of the identifiable assets acquired and the liabilities assumed in a business combination. We assess goodwill for impairment annually, in the fourth quarter of each fiscal year, and whenever events or changes in circumstances indicate that the carrying value of goodwill may exceed its fair value, at the consolidated-level, which is the sole reporting unit. When assessing goodwill for impairment, we consider our market capitalization adjusted for a control premium and, if necessary, our discounted cash flow model, which involves significant assumptions and estimates, including our future financial performance, weighted-average cost of capital and interpretation of currently enacted tax laws. Circumstances that could indicate impairment and require us to perform an impairment test include a significant decline in our financial results, a significant decline in our market capitalization relative to our net book value, an unanticipated change in competition or our market share and a significant change in our strategic plans.

Provision for Income Taxes

We use the asset and liability method in accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based upon the difference between the consolidated financial statement carrying amounts and the tax basis of assets and liabilities and are measured using the enacted tax rates expected to apply to taxable income in the years in which the differences are expected to be reversed.

The calculation of our tax assets and liabilities involves uncertainties in the application of complex tax regulations. We recognize liabilities for uncertain tax positions based on the two-step process prescribed by applicable accounting principles. The first step is to evaluate the tax position for recognition by determining if the weight of available evidence indicates that it is more likely than not that the position will be sustained upon tax authority examination, including resolution of related appeals or litigation processes, if any. The second step requires us to estimate the tax benefit as the largest amount that is more likely than not of being realized upon ultimate settlement. It is inherently difficult and subjective to estimate such amounts, as this requires us to determine the probability of various possible outcomes. We re-evaluate these uncertain tax positions on a quarterly basis. This evaluation is based on factors including changes in facts or

circumstances, changes in tax law, effectively settled issues under audit and new audit activity. Such a change in recognition or measurement could result in the recognition of a tax benefit or an additional charge to the tax provision in the relevant period.

As of December 31, 2015, we had $10.1 million of uncertain tax positions. As of December 31, 2014, we had $0.5 million of uncertain tax positions that were acquired related to the purchase of Silevo and Zep Solar.

As of December 31, 2015 and 2014, we had net deferred tax assets of $367.8 million and $111.2 million, respectively. During these periods, we maintained valuation allowances against these net deferred tax assets.

Our deferred tax assets prior to 2015, primarily relate to net operating loss, or NOL, carryforwards, accelerated gains for tax purposes, stock options, and deferred revenue. In 2015, our deferred tax assets primarily are related to deferred revenues, stock options, and the book versus tax basis differences in the joint venture funds. Our deferred tax asset valuation allowance is determined in accordance with the provisions of ASC 740, *Income Taxes*, which requires an assessment of both negative and positive evidence when measuring the need for a valuation allowance. Based on the available objective evidence and our history of losses, we believe it is more likely than not that our net deferred tax assets will not be realized.

We make estimates and judgments about our future taxable income that are based on assumptions that are consistent with our plans and estimates. The amount of our valuation allowance could be materially affected should the actual amounts differ from our estimates. Any adjustment to the deferred tax asset valuation allowance would be recorded in our consolidated statements of operations in the period in which the adjustment is determined to be required.

In the current year, we utilized all available NOL carryforwards from prior years. The utilization of the remaining NOL carryforwards and credits may be subject to a substantial annual limitation due to the ownership change limitations provided by the IRC Section 382 and similar state provisions. The annual limitation may result in the expiration of NOL carryforwards and credits before utilization. We completed an IRC Section 382 analysis through December 31, 2015. Based on the analysis, the NOL carryforwards presented have accounted for any limited and potential lost attributes due to any ownership changes and expiration dates. We also analyzed the NOL carryovers related to our acquisitions of Zep Solar and Silevo. Based on the analysis, there were no significant limitations to the utilization of either Zep Solar's or Silevo's NOL carryforwards. The NOL carryforwards presented are not expected to expire unutilized.

As part of our asset monetization strategy, we have agreements to sell solar energy systems to financing funds. The gain on the sale of the assets has been eliminated in our consolidated financial statements. These transactions are treated as inter-company sales, and as such, income taxes are not recognized on the sales until we no longer benefit from the underlying asset. Since the assets remain within the consolidated group, the income tax expense incurred related to the sales is being deferred and amortized over the estimated useful life of the assets, which has been estimated to be 30 years. The deferral of income tax expense results in the recording of a prepaid tax expense that is included in our consolidated balance sheets as other assets. The amortization of the prepaid tax expense in each period makes up the major component of our income tax expense.

In November 2015, the FASB issued Accounting Standards Update, or ASU, No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, to eliminate the requirement to classify deferred income tax assets and liabilities between current and noncurrent. The ASU simply requires that all deferred income tax assets and liabilities be classified as noncurrent. The ASU is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. Adoption of the ASU is either retrospective to each prior period presented or prospective. As of December 31, 2015, we early adopted the ASU prospectively. As a result, we no longer present any current deferred income tax assets or liabilities but did not reclassify prior period deferred income tax assets or liabilities, as permitted by the ASU.

Noncontrolling Interests and Redeemable Noncontrolling Interests

Our noncontrolling interests and redeemable noncontrolling interests represent third-party interests in the net assets under certain funding arrangements, or funds, that we have entered into to finance the costs of solar energy systems under operating leases, as well as under a limited partnership operated by one of our acquired subsidiaries in China. We have determined that the contractual provisions of the funds and the limited partnership represent substantive profit sharing arrangements. We have further determined that the appropriate methodology for calculating the noncontrolling interests and redeemable noncontrolling interests balance that reflects the substantive profit sharing arrangements is a balance sheet approach using the HLBV method for the funds. We therefore determine the amount of the noncontrolling interests and redeemable noncontrolling interests in the net assets at each balance sheet date using the HLBV method for the funds, which is presented on our consolidated balance sheets as noncontrolling interests in subsidiaries and redeemable noncontrolling interests in subsidiaries. Under the HLBV method, the amounts reported as noncontrolling interests and redeemable noncontrolling interests in our consolidated balance sheets represent the amounts the third-parties would

hypothetically receive at each balance sheet date under the liquidation provisions of the funds, assuming the net assets of the funds were liquidated at their recorded amounts determined in accordance with GAAP and distributed to the third-parties. The third-parties' interests in the results of operations of the funds are determined as the difference in the noncontrolling interests and redeemable noncontrolling interests balance in our consolidated balance sheets between the start and end of each reporting period, after taking into account any capital transactions between the funds and the third-parties. However, for both the funds and the limited partnership, the redeemable noncontrolling interests balance is at least equal to the redemption amount. The noncontrolling interests balance is presented as a component of permanent equity in our consolidated balance sheets, and the redeemable noncontrolling interests balance is presented as temporary equity in the mezzanine section of our consolidated balance sheets when the third-parties have the right to redeem their interests in the funds or the limited partnership for cash or other assets.

Results of Operations

The following table sets forth selected consolidated statements of operations data for each of the periods indicated (in thousands, except share and per share amounts).

	Year Ended December 31,		
	2015	2014	2013
Revenue:			
Operating leases and solar energy systems incentives	$ 293,543	$ 173,636	$ 82,856
Solar energy systems and components sales	106,076	81,395	80,981
Total revenue	399,619	255,031	163,837
Cost of revenue:			
Operating leases and solar energy systems incentives	165,546	92,920	32,745
Solar energy systems and components sales	115,245	83,512	91,723
Total cost of revenue	280,791	176,432	124,468
Gross profit	118,828	78,599	39,369
Operating expenses:			
Sales and marketing	457,185	238,608	97,426
General and administrative	244,508	156,426	89,801
Research and development	64,925	19,162	1,520
Total operating expenses	766,618	414,196	188,747
Loss from operations	(647,790)	(335,597)	(149,378)
Interest expense, net	91,939	55,758	25,738
Other expense, net	25,767	10,611	1,441
Loss before income taxes	(765,496)	(401,966)	(176,557)
Income tax (provision) benefit	(3,326)	26,736	24,799
Net loss	(768,822)	(375,230)	(151,758)
Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(710,492)	(319,196)	(95,968)
Net loss attributable to stockholders	$ (58,330)	$ (56,034)	$ (55,790)
Net loss attributable to common stockholders			
Basic	$ (58,330)	$ (56,034)	$ (55,790)
Diluted	$ (58,330)	$ (56,034)	$ (55,790)
Net loss per share attributable to common stockholders			
Basic	$ (0.60)	$ (0.60)	$ (0.70)
Diluted	$ (0.60)	$ (0.60)	$ (0.70)
Weighted-average shares used to compute net loss per share attributable to common stockholders			
Basic	97,200,925	93,333,880	79,781,976
Diluted	97,200,925	93,333,880	79,781,976

Revenue

	Year Ended December 31,			Change 2015 vs. 2014		Change 2014 vs. 2013	
(Dollars in thousands)	2015	2014	2013	$	%	$	%
Operating leases and solar energy systems incentives	$293,543	$173,636	$ 82,856	$119,907	69%	$ 90,780	110%
	106,076	81,395	80,981	24,681	30%	414	1%

Solar energy systems and components sales							
Total revenue	$399,619	$255,031	$163,837	$144,588	57%	$ 91,194	56%

2015 Compared to 2014

Total revenue increased by $144.6 million, or 57%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014.

Operating leases and solar energy systems incentives revenue increased by $119.9 million, or 69%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily attributable to the increase in solar energy systems placed in service under leases and power purchase agreements in 2015. The in-period average of the aggregate megawatt production capacity of solar energy systems placed in service under leases and power purchase agreements during the year ended December 31, 2015 increased by 79% as compared to the in-period average during the year ended December 31, 2014. This significant growth was attributable to our continued success in the installation and operation of solar energy systems under lease and power purchase agreements in new and existing markets. In addition, revenue from the monetization of ITCs increased by $19.8 million for the year ended December 31, 2015, as compared to the year ended December 31, 2014, as we recognized such revenue from more solar energy systems in the year ended December 31, 2015. We recognize revenue from the monetization of ITCs on the anniversary date of each solar energy system's placed in service date as ITC recapture provisions expire.

Revenue from sales of solar energy systems and components increased by $24.7 million, or 30%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to the $29.8 million increase in revenue from MyPower contracts, the $13.0 million increase in revenue from outright sales to residential customers, the $4.0 million increase in revenue from sales to government entities, the $1.1 million increase in revenue from sales by Ilioss, which we acquired in August 2015, the $0.8 million increase in revenue from sales of battery storage products and the $0.3 million increase in revenue from sales of Silevo products as we fulfilled open customer orders following our acquisition of Silevo. These increases were partially offset by the $9.0 million decrease in revenue from sales of Zep Solar products, the $8.7 million decrease in revenue from long-term solar energy system sales contracts recognized on the percentage-of-completion basis and the $7.5 million decrease in revenue from sales to commercial customers. Revenue from sales of solar energy systems and components has varied considerably and will continue to vary considerably from period to period due to the successful adoption of our MyPower product and the unpredictability of sales to commercial customers, long-term solar energy system sales contracts recognized on the percentage-of-completion basis and sales to government entities.

2014 Compared to 2013

Total revenue increased by $91.2 million, or 56%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Operating leases and solar energy systems incentives revenue increased by $90.8 million, or 110%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was attributable to the increase in solar energy systems placed in service under leases and power purchase agreements between January 1, 2013 and December 31, 2014. The in-period average of the aggregate megawatt production capacity of solar energy systems placed in service under leases and power purchase agreements during the year ended December 31, 2014 increased by 97% as compared to the in-period average during the year ended December 31, 2013. This significant growth was attributable to our continued success in the installation and operation of solar energy systems under lease and power purchase agreements in new and existing markets. However, the impact of the installed base on the increase in revenue varied by the mix between solar energy systems under leases, for which revenue is recognized on a straight-line basis over the lease term, and power purchase agreements, for which revenue is recognized based on the energy produced. In addition, revenue from the monetization of ITCs increased by $27.7 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013, as we recognized revenue from monetization of ITCs related solar energy systems that were placed in service in the year ended December 31, 2013. We recognize revenue from monetization of ITCs on the anniversary date of each solar energy system's placed in service date as recapture provisions expire.

Revenue from sales of solar energy systems and components increased by $0.4 million, or 1%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was primarily due to a $21.6 million increase in revenue from long-term solar energy system sales contracts recognized on the percentage-of-completion basis, a $5.6 million increase in revenue from sales to residential customers and $1.1 million of revenue from sales of Silevo products in the year ended December 31, 2014. Additionally, in the year ended December 31, 2014, we recorded $9.0 million in revenue from sales of Zep Solar products as we fulfilled open customer orders following our acquisition of Zep Solar. Subsequent to the fulfillment of all external Zep Solar sales orders, we have internally consumed the Zep Solar product in solar energy system installations for our customers. These increases were partially offset by a $26.0 million decrease in revenue from sales to government entities, a $5.0 million decrease in revenue from sales of energy efficiency products and services and a $4.6 million decrease in revenue from sales to commercial customers. Through December 31, 2014, revenue from MyPower arrangements has been immaterial.

Cost of Revenue, Gross Profit and Gross Profit Margin

(Dollars in thousands)	Year Ended December 31, 2015	2014	2013	Change 2015 vs. 2014 $	%	Change 2014 vs. 2013 $	%
Cost of operating leases and solar energy systems incentives	$165,546	$ 92,920	$ 32,745	$ 72,626	78%	$ 60,175	184%
Gross profit of operating leases and solar energy systems incentives	127,997	80,716	50,111	47,281	59%	30,605	61%
Gross profit margin of operating leases and solar energy systems incentives	44%	46%	60%				
Cost of solar energy systems and component sales	$115,245	$ 83,512	$ 91,723	$ 31,733	38%	$ (8,211)	(9)%
Gross loss of solar energy systems and component sales	(9,169)	(2,117)	(10,742)	(7,052)	333%	8,625	(80)%
Gross loss margin of solar energy systems and component sales	(9)%	(3)%	(13)%				
Total cost of revenue	$280,791	$176,432	$124,468	$104,359	59%	$ 51,964	42%
Total gross profit	118,828	78,599	39,369	40,229	51%	39,230	100%
Total gross profit margin	30%	31%	24%				

2015 Compared to 2014

Cost of operating leases and solar energy systems incentives revenue increased by $72.6 million, or 78%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to greater depreciation expense arising from the higher aggregate cost of solar energy systems placed in service and generating revenue under solar energy system leases and power purchase agreements. Additionally, we incurred $15.5 million of increased period costs related to customer contract cancellations, our dedicated operations and maintenance department and customer warranties. We also incurred $7.5 million of increased expenses due to the continuing amortization of intangible assets related to the Silevo acquisition in the third quarter of 2014.

Cost of solar energy systems and component sales increased by $31.7 million, or 38%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was partly due to higher sales of solar energy systems and components and also the recognition of $17.0 million of warranty expenses associated with sales under MyPower contracts. The warranty expense for a sale under a MyPower contract is recorded upon the delivery of the solar energy system while the associated revenue and cost of revenue are recognized over the term of the MyPower contract as the customer pays-down the principal balance of the MyPower loan. We expect to continue to record negative gross margins in future periods as sales under MyPower contracts increase and revenue is recognized over the term of the MyPower contracts.

2014 Compared to 2013

Cost of operating leases and solar energy systems incentives revenue increased by $60.2 million, or 184%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was primarily due to the increase in depreciation expense arising from the higher aggregate cost of solar energy systems placed in service under leases and power purchase agreements. Additionally, we incurred $14.4 million of increased period costs related to customer contract cancellations, our dedicated operations and maintenance department and customer warranties. We also incurred $9.4 million of increased expenses due to the continuing amortization of intangible assets related to the Zep Solar acquisition in the fourth quarter of 2013 and the Silevo acquisition in the third quarter of 2014. Furthermore, the percentage of depreciation expense that was offset by the amortization of U.S. Treasury grants received continued to

decrease, from 42% for the year ended December 31, 2013 to 25% for the year ended December 31, 2014, as no significant new grants have been received in 2014 due to the winding-down of the U.S. Treasury grant program.

Cost of solar energy systems and component sales decreased by $8.2 million, or 9%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in our total deployment of solar energy systems resulted in the allocation of overhead costs over more megawatts installed. In addition, the percentage of residential sales increased in 2014, which generally have higher gross margins in comparison to larger scale commercial and government sales as recognized in the year ended December 31, 2013. Furthermore, non-recurring Zep Solar product sales in the year ended December 31, 2014 had generally higher gross margins than the solar energy systems sales. These factors contributed to an improvement in the gross margin loss from (13%) to (3%).

Operating Expenses

(Dollars in thousands)	Year Ended December 31, 2015	2014	2013	Change 2015 vs. 2014 $	%	Change 2014 vs. 2013 $	%
Sales and marketing	$457,185	$238,608	$ 97,426	$218,577	92%	$ 141,182	145%
General and administrative	244,508	156,426	89,801	88,082	56%	66,625	74%
Research and development	64,925	19,162	1,520	45,763	239%	17,642	1161%
Total operating expenses	$766,618	$414,196	$188,747	$352,422	85%	$ 225,449	119%

2015 Compared to 2014

Sales and marketing expense increased by $218.6 million, or 92%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to more expansive sales and marketing efforts, which have resulted in increases in the number of customers, system installations and system deployments. This initiative increased the average number of personnel in sales and marketing departments by 103% for the year ended December 31, 2015, as compared to the year ended December 31, 2014. As a result of this growth in headcount, employee compensation costs increased by $137.9 million (of which $7.8 million was related to stock-based compensation) and facilities and operations costs increased by $25.7 million. In addition, promotional marketing costs increased by $53.5 million as part of this broadening of the scope of our marketing activities, including enhanced digital marketing activities to increase brand awareness and customer reach. In the future, we expect to reduce our sales and marketing expenses, on a per Watt basis, by focusing on our more efficient sales channels, renegotiating or eliminating our higher cost sales channels and other cost efficiency initiatives.

General and administrative expense increased by $88.1 million, or 56%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to the increase in the average number of personnel in general and administrative departments, which grew by 103% for the year ended December 31, 2015, as compared to the year ended December 31, 2014. As a result of this growth in headcount, employee compensation costs increased by $45.5 million (of which $4.2 million was related to stock-based compensation) and facilities and operations costs increased by $13.6 million. In addition, professional services fees increased by $22.9 million primarily due to increased legal costs and accounting services fees. Furthermore, Ilioss, which we acquired in August 2015, incurred $1.7 million of general and administrative expenses in the year ended December 31, 2015.

Research and development expense increased by $45.8 million, or 239%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to the greater level of research and development activities undertaken by Silevo and the corresponding increase in the average number of personnel in research and development departments, which grew by 227% for the year ended December 31, 2015, as compared to the year ended December 31, 2014.

2014 Compared to 2013

Sales and marketing expense increased by $141.2 million, or 145%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was primarily due to more expansive sales and marketing efforts, that have resulted in an increase in the overall backlog, number of customers and deployments. In particular, we acquired certain assets of a leading direct-to-consumer marketer, Paramount Energy, including its employees, technology and tools, in the third quarter of 2013, and we created a dedicated door-to-door direct sales group in the fourth quarter 2013. These initiatives increased the average number of personnel in sales and marketing departments by 180% for the year ended December 31, 2014 as compared to the year ended December 31, 2013. As a result of this growth in headcount, employee compensation costs increased by $88.9 million, of which $12.4 million was non-cash and related to stock-based compensation. In addition, facilities and operations costs increased by $13.0 million, promotional marketing costs increased by $29.3 million and expenses from the non-cash amortization of marketing-related intangible assets, acquired through the Paramount Energy and Zep Solar acquisitions, increased by $8.9 million. We expect that our increased investment in sales and marketing efforts will continue to drive the future growth of our business.

General and administrative expense increased by $66.6 million, or 74%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was primarily due to the increase in the average number of

personnel in general and administrative departments, which grew by 80% for the year ended December 31, 2014 as compared to the year ended December 31, 2013. As a result of this growth in headcount, employee compensation costs increased by $48.2 million, of which $25.0 million was non-cash and related to stock-based compensation, and facilities and operations costs increased by $7.9 million. In addition, professional services fees increased by $11.0 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013, primarily due to increased audit fees, our efforts with regard to compliance with the Sarbanes-Oxley Act of 2002 and increased financing activities.

Research and development expense increased by $17.6 million, or 1,161%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This was primarily due to the product research and development activities undertaken by Zep Solar, which we acquired in the fourth quarter of 2013, and by Silevo, which we acquired in the third quarter 2014.

Other Income and Expenses

	Year Ended December 31,			Change 2015 vs. 2014		Change 2014 vs. 2013	
(Dollars in thousands)	2015	2014	2013	$	%	$	%
Interest expense, net	$ 91,939	$ 55,758	$ 25,738	$ 36,181	65%	$ 30,020	117%
Other expense, net	25,767	10,611	1,441	15,156	143%	9,170	636%
Total interest and other expenses, net	$117,706	$ 66,369	$ 27,179	$ 51,337	77%	$ 39,190	144%

2015 Compared to 2014

Interest expense, net, increased by $36.2 million, or 65%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase was primarily due to the $36.8 million increase in interest expense, net, attributable to the higher average carrying balances on our various borrowing facilities for the year ended December 31, 2015, as compared to the year ended December 31, 2014.

Other expense, net, increased by $15.2 million, or 143%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This increase in was mainly due to the $11.6 million loss from interest rate swaps related to our debt facilities, the $2.4 million loss from the settlement for Seaboard projects and the $5.3 million increase in accretion on the contingent consideration related to the Silevo acquisition, in the year ended December 31, 2015. We have entered into forward interest rate swaps in order to fix the variable interest rates for each draw under certain credit facilities. We account for interest rate swaps as non-hedging derivatives. This increase was partially offset by the $3.1 million decrease in loss on debt extinguishment.

2014 Compared to 2013

Interest expense, net, increased by $30.0 million, or 117%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The interest expense, net, related to our cash borrowings increased by $31.6 million as a result of higher average carrying balances on our borrowing facilities for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in interest expense, net, related to our cash borrowings was partially offset by a decrease of $1.6 million of interest expense, net, related to our lease pass-through fund arrangements, mainly due to lower average lease pass-through financing obligation balances during the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Other expense, net, increased by $9.2 million, or 636%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in other expense, net, was mainly due to a $4.5 million charge related to the settlement of certain debt in the year ended December 31, 2014 and a $1.9 million charge related to the accretion on the contingent consideration payable to certain Silevo employees negotiated as part of the Silevo acquisition agreement. Additionally, franchise taxes increased by $1.1 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Net Loss Attributable to Noncontrolling Interests and Redeemable Noncontrolling Interests

	Year Ended December 31,			Change 2015 vs. 2014		Change 2014 vs. 2013	
(Dollars in thousands)	2015	2014	2013	$	%	$	%
Net loss attributable to noncontrolling interests and redeemable noncontrolling	$(710,492)	$(319,196)	$(95,968)	$(391,296)	(123)%	$(223,228)	(233)%

The net loss attributable to noncontrolling interests and redeemable noncontrolling interests represents the share of net loss that was allocated to the investors in the joint venture financing funds. This amount was determined as the change in the investors' interests in the joint venture financing funds between the beginning and end of each reported period calculated primarily using the HLBV method, less any capital contributions net of any capital distributions. The calculation depends on the specific contractual liquidation provisions of each joint venture financing fund and is generally affected by, among other factors, the tax attributes allocated to the investors including tax bonus depreciation and ITCs or U.S. Treasury grants in lieu of the ITCs, the existence of guarantees of minimum returns to the investors by us and the allocation of tax income or losses including provisions that govern the level of deficits that can be funded by the investors in a liquidation scenario. The calculation is also affected by the cost of the assets sold to the joint venture financing funds, which forms the book basis of the net assets allocated to the investors assuming a liquidation scenario. Generally, significant loss allocations to the investors have arisen in situations where there was a significant difference between the fair value and the cost of the assets sold to the joint venture financing funds in a particular period accompanied by the absence of guarantees of minimum returns to the investors by us, since the capital contributions by the investors were based on the fair value of the assets while the calculation is based on the cost of the assets. The existence of guarantees of minimum returns to the investors by us and limits on the level of deficits that the investors are contractually obligated to fund in a liquidation scenario reduce the amount of losses that could be allocated to the investors. In addition, the redeemable noncontrolling interests balance is at least equal to the redemption amount.

2015 Compared to 2014

The net loss allocation to noncontrolling interests and redeemable noncontrolling interests for the year ended December 31, 2015 was $710.5 million compared to $319.2 million loss allocation for year ended December 31, 2014. The net loss allocation to noncontrolling interests and redeemable noncontrolling interests for the year ended December 31, 2015 was primarily due to a $701.9 million loss allocation from financing funds into which we were selling or contributing assets. The net loss allocation to noncontrolling interests and redeemable noncontrolling interests for the year ended December 31, 2014 was primarily due to a $345.4 million loss allocation from financing funds into which we were selling or contributing assets. This loss allocation was partially offset by a $25.9 million income allocation related to financing funds that were fully funded and that we were not selling or contributing additional assets.

2014 Compared to 2013

The net loss allocation to noncontrolling interests and redeemable noncontrolling interests for the year ended December 31, 2014 was primarily due to a $345.4 million loss allocation from financing funds into which we were selling or contributing assets. This loss allocation was partially offset by a $13.6 million income allocation related to financing funds that were fully funded and that we were not selling or contributing additional assets. Additionally, $12.3 million of income was allocated to noncontrolling interests and redeemable noncontrolling interests in an entity that has a lease pass-through fund arrangement with us, including $8.5 million of income allocated due to adjustments of the carrying value of the redeemable noncontrolling interest balance to its redemption amount following amendments to the contractual agreements of the entity that granted the investor redemption rights in conjunction with the termination of the lease pass-through fund arrangement. The net loss allocation to noncontrolling interests and redeemable noncontrolling interests for the year ended December 31, 2013 was primarily due to a $165.7 million loss allocation from financing funds into which we were selling or contributing assets. This loss allocation was partially offset by a $57.8 million income allocation related to a single financing fund whose contractual documents were amended in 2013. The amendments were made to ensure that the investor in this financing fund would earn, in the future, amounts equal to the anticipated shortfalls in U.S. Treasury grants related to the assets previously sold to this financing fund. Furthermore, $10.3 million of income was allocated to noncontrolling interests and redeemable noncontrolling interests in an entity that has a lease pass-through fund arrangement with us.

Quarterly Results of Operations

The following table presents our unaudited consolidated statements of operations for each of the quarters indicated. Our consolidated statements of operations for each of these quarters have been prepared on a basis consistent with our audited annual consolidated financial statements included elsewhere in this annual report on Form 10-K and, in the opinion of management, include all adjustments necessary for the fair presentation of our consolidated results of operations for these quarters. You should read this information together with our annual consolidated financial statements and the accompanying notes included elsewhere in this annual report on Form 10-K. Our quarterly results of operations are not necessarily indicative of our results for any future period.

	Three Months Ended							
	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
	(in thousands, except share and per share amounts)							
Revenue:								
Operating leases and solar energy systems incentives	$ 75,430	$ 85,059	$ 78,283	$ 54,771	$ 49,205	$ 52,178	$ 43,181	$ 29,072
Solar energy systems and components sales	40,050	28,798	24,520	12,708	22,603	6,165	18,153	34,474
Total revenue	115,480	113,857	102,803	67,479	71,808	58,343	61,334	63,546
Cost of revenue:								
Operating leases and solar energy systems incentives	49,879	46,015	37,392	32,260	30,387	25,728	20,826	15,979
Solar energy systems and components sales	37,144	42,554	22,087	13,460	26,455	6,640	17,635	32,782
Total cost of revenue	87,023	88,569	59,479	45,720	56,842	32,368	38,461	48,761
Gross profit	28,457	25,288	43,324	21,759	14,966	25,975	22,873	14,785
Operating expenses:								
Sales and marketing	128,070	129,284	113,160	86,671	79,515	56,472	55,771	46,850
General and administrative	76,220	69,423	50,211	48,654	45,420	39,608	38,387	33,011
Research and development	22,752	17,652	12,401	12,120	10,004	4,235	3,000	1,923
Total operating expenses	227,042	216,359	175,772	147,445	134,939	100,315	97,158	81,784
Loss from operations	(198,585)	(191,071)	(132,448)	(125,686)	(119,973)	(74,340)	(74,285)	(66,999)
Interest expense, net	27,059	25,862	20,497	18,521	18,566	16,321	12,892	7,979
Other expense, net	4,044	16,851	2,768	2,104	6,318	2,961	1,307	25
Loss before income taxes	(229,688)	(233,784)	(155,713)	(146,311)	(144,857)	(93,622)	(88,484)	(75,003)
Income tax (provision) benefit	(2,198)	(482)	(20)	(626)	3,421	23,506	24	(215)
Net loss	(231,886)	(234,266)	(155,733)	(146,937)	(141,436)	(70,116)	(88,460)	(75,218)
Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(236,514)	(215,193)	(133,373)	(125,412)	(137,881)	(89,352)	(40,808)	(51,155)
Net income (loss) attributable to stockholders	$ 4,628	$ (19,073)	$ (22,360)	$ (21,525)	$ (3,555)	$ 19,236	$ (47,652)	$ (24,063)
Net income (loss) attributable to common stockholders								
Basic	$ 4,628	$ (19,073)	$ (22,360)	$ (21,525)	$ (3,555)	$ 19,236	$ (47,652)	$ (24,063)
Diluted	$ 4,630	$ (19,073)	$ (22,360)	$ (21,525)	$ (3,555)	$ 19,236	$ (47,652)	$ (24,063)

Net income (loss) per share attributable to common stockholders								
Basic	$ 0.05	$ (0.20)	$ (0.23)	$ (0.22)	$ (0.04)	$ 0.21	$ (0.52)	$ (0.26)
Diluted	$ 0.04	$ (0.20)	$ (0.23)	$ (0.22)	$ (0.04)	$ 0.19	$ (0.52)	$ (0.26)
Weighted-average shares used to compute net income (loss) per share attributable to common stockholders								
Basic	97,714,725	97,384,949	97,013,499	96,680,069	96,296,151	93,323,687	92,251,767	91,412,126
Diluted	102,942,993	97,384,949	97,013,499	96,680,069	96,296,151	99,380,397	92,251,767	91,412,126

Liquidity and Capital Resources

The following table summarizes our consolidated cash flows:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Consolidated cash flow data:			
Net cash (used in) provided by operating activities	$ (789,884)	$ (217,849)	$ 174,515
Net cash used in investing activities	(1,726,734)	(1,344,814)	(729,899)
Net cash provided by financing activities	2,394,779	1,489,966	972,384
Net decrease in cash and cash equivalents	$ (121,839)	$ (72,697)	$ 417,000

We finance our operations, including the costs of acquisition and installation of solar energy systems, mainly through a variety of financing fund arrangements that we have formed with fund investors, credit facilities from banks, solar asset-backed notes, convertible notes, Solar Bonds and cash generated from our operations. As described below under "—Financing Activities— Debt and Financing Fund Commitments," as of December 31, 2015, we had $657.7 million of available commitments from our fund investors and $234.2 million of unused borrowing capacity available under our credit facilities. In future periods, we expect to incur additional capital expenses as we invest further in our solar module manufacturing operations, technology platform and proprietary mounting and racking hardware. In particular, we may incur substantial expenses in connection with the completion of the manufacturing facility under construction in New York and as we purchase equipment in excess of the amounts spent by the Foundation.

The amount of our liquidity and capital resources as of a given date is also dependent upon, among other things, the relative timing of our investments in solar energy systems and the timing of subsequent draws on our financing funds. As a result, the amount of our liquidity and capital resources may significantly fluctuate within a reporting period by amounts that are not reflected by comparing our cash and cash equivalents balances at each balance sheet date. For example, solar energy systems deployed towards the end of a fiscal quarter may not be transferred to a financing fund in sufficient time for the funds to be received and reflected in our cash and cash equivalents balance as of the quarter-end. In addition, downward revisions to our installation projections for a fiscal period are also likely to impact our liquidity and capital resources, for example, in situations where we have already spent funds to purchase components for solar energy systems that are installed in subsequent periods. As our business grows and the megawatts deployed increases, the amounts by which our liquidity and capital resources may fluctuate within a quarter are likely to increase.

While we had a net loss for the year ended December 31, 2015, we believe that the aggregate of our existing cash and cash equivalents and short-term investments of $393.9 million, in addition to the funds available under our debt agreements and the funds available in our existing financing funds that can be drawn-down through our asset monetization strategy, will be sufficient to meet our cash requirements for at least the next 12 months. However, if, in the future, we are unable to comply with all of the covenants contained in our debt agreements or we are unable to obtain waivers of any non-compliance, then we might be considered in default under our debt agreements. In that circumstance, the payments due under our debt agreements could be accelerated, which would negatively impact our liquidity and capital resources. Under the terms of our secured revolving credit facility, we are subject to the following financial covenants:

Interest Coverage Ratio: We are obligated to maintain an interest coverage ratio of 1.5-to-1 as of the end of each fiscal quarter. The interest coverage ratio is measured by dividing (a) an amount equal to the excess of (i) our trailing 12-month consolidated gross profit over (ii) 20% of our trailing 12-month consolidated general and administrative expenses by (b) our unconsolidated trailing 12-month cash interest charges.

Unencumbered Liquidity: We are obligated to maintain unencumbered liquidity at an amount equal to at least 20% of the sum of (a) the committed amount under the secured revolving credit facility plus (b) the aggregate principal outstanding of Solar Bonds that mature prior to the secured revolving credit facility's maturity date, as of the end of each month. However, unencumbered liquidity can never be less than $50.0 million, as of the end of each month. Unencumbered liquidity is defined as our average daily cash and cash equivalents, excluding certain of our subsidiaries.

Under the terms of certain borrowings by our subsidiaries, certain of our subsidiaries are subject to the following financial covenants:

Interest Coverage Ratio: Certain of our subsidiaries are obligated to maintain an interest coverage ratio of 1.4-to-1 as of the specified dates and periods. The interest coverage ratio is measured by dividing (a) the subsidiary's revenue less the specified expenses and fees by (b) cash interest charges plus the specified fees.

Debt Service Coverage Ratio: Certain of our subsidiaries are obligated to maintain a debt service coverage ratio of 1.05-to-1 as of the specified dates and periods. The debt service coverage ratio is measured by dividing (a) the specified cash receipts of the subsidiary less the specified cash payments by (b) cash interest charges plus any principal due and payable.

Operating Activities

In the year ended December 31, 2015, we utilized $789.9 million in net cash from operations. This cash outflow primarily resulted from a net loss of $768.8 million reduced by non-cash items such as depreciation and amortization of $166.7 million, stock-based compensation of $86.4 million and non-cash interest and other expense of $16.4 million mainly related to lease pass-through financing obligations and deferred contingent consideration and increased by a reduction in lease pass-through financing obligation of $48.1 million and the tax benefit of stock option exercises of $63.0 million. The cash outflow also increased in part due to an increase in restricted cash of $48.7 million, an increase in accounts receivable of $11.0 million, an increase in inventories of $125.3 million, an increase in prepaid expenses and other current assets of $24.5 million, an increase in other assets of $70.0 million, and an increase in MyPower deferred costs of $202.9 million. This cash outflow was offset by a decrease in rebates receivable of $18.5 million, an increase in accounts payable of $125.5 million, an increase in accrued and other liabilities of $147.5 million, and an increase in deferred revenue under our joint venture and lease pass-through structures of $11.5 million relating to upfront lease payments received from customers, solar energy system incentive rebate payments received from various state and local governments and deferred investment tax credits revenue.

In the year ended December 31, 2014, we utilized $217.8 million in net cash from operations. This cash outflow primarily resulted from a net loss of $375.2 million reduced by non-cash items such as depreciation and amortization of $97.9 million, stock-based compensation of $65.6 million and non-cash interest expense of $13.6 million mainly related to lease pass-through financing obligations and increased by a reduction in lease pass-through financing obligation of $48.8 million and the release of $26.7 million of deferred tax asset valuation allowances as a result of the Silevo acquisition. The cash outflow also increased in part due to an increase in restricted cash of $17.7 million, an increase in rebates receivable of $9.9 million, an increase in inventories of $97.3 million, an increase in prepaid expenses and other current assets of $23.6 million, an increase in other assets of $32.0 million and a decrease in accrued and other liabilities of $22.7 million. This cash outflow was offset by an increase in deferred revenue under our joint venture and lease pass-through structures of $137.9 million relating to upfront lease payments received from customers, solar energy system incentive rebate payments received from various state and local governments and deferred investment tax credits revenue and an increase in accounts payable of $112.5 million.

In the year ended December 31, 2013, we generated $174.5 million in net cash from operations. This cash inflow primarily resulted from an increase in deferred revenue of $233.6 million relating to upfront lease payments received from customers and solar energy system incentive rebate payments received from various state and local governments and deferred investment tax credits revenue, an increase in accounts payable of $50.8 million, an increase in accrued and other liabilities of $84.4 million and a decrease in accounts receivable of $2.9 million. The cash inflow was offset in part by an increase in restricted cash of $13.1 million, an increase in incentive rebates receivable of $2.6 million, an increase in inventories of $20.0 million, an increase in prepaid and other current assets of $19.3 million and a net loss of $151.8 million reduced by non-cash items such as depreciation and amortization of $41.4 million, stock-based compensation of $21.3 million and interest on lease pass-through financing obligation of $13.4 million and increased by a reduction in lease pass-through financing obligation of $35.7 million and a change in deferred income taxes of $25.4 million.

Investing Activities

Our investing activities consist primarily of purchases of solar energy systems, capital expenditures for our module research and development and our panel manufacturing and general corporate purchases to support our standard operations.

In the year ended December 31, 2015, we used $1,726.7 million in investing activities. Of this amount, we used $1,665.6 million on the design, acquisition and installation of solar energy systems under operating leases with our customers, $176.5 million in the acquisition of solar panel manufacturing equipment, vehicles, office equipment, leasehold improvements and furniture and $9.5 million for the acquisition of Ilioss. We also invested $44.6 million in short-term

investments in highly rated corporate debt securities and asset-backed securities. These expenditures were offset by $170.7 million from sales and maturities of short-term investments.

In the year ended December 31, 2014, we used $1,344.8 million in investing activities. Of this amount, we used $1,163.0 million on the design, acquisition and installation of solar energy systems under operating leases with our customers, $22.9 million on the acquisition of vehicles, office equipment, leasehold improvements and furniture and $0.5 million for the acquisition of the redeemable noncontrolling interest related to a single joint venture financing fund. We also invested $21.8 million in promissory notes receivable and other investments and $167.4 million in short-term investments in highly rated corporate debt securities and asset-backed securities. These expenditures were offset by $1.9 million net cash inflow from the acquisition of Silevo and $28.8 million from sales and maturities of short-term investments.

In the year ended December 31, 2013, we used $729.9 million in investing activities. Of this amount, we used $717.0 million on the design, acquisition and installation of solar energy systems under operating leases with our customers and $9.1 million on the acquisition of vehicles, office equipment, leasehold improvements and furniture. We also invested $3.8 million on the acquisitions of businesses.

Financing Activities

In the year ended December 31, 2015, we generated $2,394.8 million from financing activities. We received $1,093.3 million, net of lender fees, from long-term debt and repaid $215.9 million of long-term debt. We received $119.8 million, net of issuance costs, from the issuance of solar asset-backed notes and repaid $15.9 million of the solar asset-backed notes. We received $112.8 million, net of issuance costs, from the issuance of zero-coupon convertible senior notes. We received $212.2 million from the issuance of solar bonds and repaid $2.2 million of solar bonds. We received $43.1 million from fund investors in our financing funds and paid $5.3 million to fund investors in our financing funds. We also generated $1,097.5 million from proceeds from investments by various investors in our joint venture financing funds, paid distributions to fund investors of $109.5 million and generated $63.0 million from the tax benefit of stock option exercises. Additionally, we paid $3.7 million for deferred purchase consideration and paid $6.0 million for capital lease obligations.

In the year ended December 31, 2014, we generated $1,490.0 million from financing activities. We received $552.8 million, net of issuance costs, from the issuance of convertible senior notes, and in conjunction with this issuance, we paid $65.2 million to enter into a capped call option agreement. We received $373.5 million, net of lender fees, from long-term debt and repaid $336.6 million of long-term debt. We received $262.9 million, net of issuance costs, from the issuance of solar asset-backed notes and repaid $5.9 million of the solar asset-backed notes. We received $44.6 million from fund investors in financing funds and paid $12.5 million to fund investors in our financing funds. We also generated $778.0 million from proceeds from investments by various investors in our joint venture financing funds and paid distributions to fund investors of $117.1 million. Additionally, we paid $2.2 million for deferred purchase consideration.

In the year ended December 31, 2013, we generated $972.4 million from financing activities. We raised $174.1 million, net of underwriting discounts, commissions and issuance costs, from a secondary issuance of our common stock. We received $222.5 million, net of issuance costs, from the issuance of convertible senior notes. We received $203.2 million, net of lender fees, from long-term debt and repaid $65.3 million of long-term debt. We received $51.3 million, net of issuance costs, from the issuance of solar asset-backed notes and repaid $1.5 million of the solar asset-backed notes. We also repaid $1.6 million of our capital lease obligation. We received $127.5 million from U.S. Treasury Department grants associated with solar energy systems that we had leased to customers. We received $57.8 million from investors in our financing funds and paid $41.5 million to investors in our financing funds. We also generated $362.7 million from proceeds from investments by various investors in our joint venture financing funds and paid distributions to fund investors of $137.0 million. Additionally, we paid $3.4 million for deferred purchase consideration.

Debt

For a detailed discussion of our indebtedness, refer to Note 11, *Indebtedness*, to our consolidated financial statements included elsewhere in this annual report on Form 10-K. Our new debt facilities are summarized below.

Zero-Coupon Convertible Senior Notes Due in 2020

In December 2015, we issued $113.0 million in aggregate principal of zero-coupon convertible senior notes due on December 1, 2020 through a private placement. $13.0 million of the convertible senior notes were issued to related parties and are separately presented on our consolidated balance sheets. The net proceeds from the offering, after deducting debt issuance costs, were $112.8 million.

Each $1,000 of principal of the convertible senior notes is initially convertible into 30.3030 shares of our common stock, which is equivalent to an initial conversion price of $33.00 per share, subject to adjustment upon the occurrence of specified events related to

dividends, tender offers or exchange offers. Holders of the convertible senior notes may convert their convertible senior notes at their option at any time up to and including the second scheduled trading day prior to maturity. If certain events that would constitute a make-whole fundamental change, such as significant changes in ownership, corporate structure or tradability of our common stock, occur prior to the maturity date, we would increase the conversion rate for a holder who elects to convert its convertible senior notes in connection with such an event in certain circumstances. The maximum conversion rate is capped at 38.4615 shares for each $1,000 of principal of the convertible senior notes, which is equivalent to a minimum conversion price of $26.00 per share. The convertible senior notes do not have a cash conversion option. The convertible senior note holders may require us to repurchase their convertible senior notes for cash only under certain defined fundamental changes. On or after June 30, 2017, the convertible senior notes will be redeemable by us in the event that the closing price of our common stock exceeds 200% of the conversion price for 45 consecutive trading days ending within three trading days of such redemption notice at a redemption price of par plus accrued and unpaid interest to, but excluding, the redemption date.

MyPower Revolving Credit Facility

On January 9, 2015, one of our subsidiaries entered into a $200.0 million revolving credit agreement with a syndicate of banks to obtain funding for the MyPower customer loan program. The MyPower revolving credit facility initially provided up to $160.0 million of Class A notes and up to $40.0 million of Class B notes. On December 16, 2015, the committed amount under the Class A notes was increased to $200.0 million. The Class A notes bear interest at an annual rate of (i) for the first $160.0 million, 2.50% and (ii) for the remaining $40.0 million, 3.00%; in each case, plus (a) the commercial paper rate or (b) 1.50% plus adjusted LIBOR. The Class B notes bear interest at an annual rate of 5.00% plus LIBOR. The fee for undrawn commitments under the Class A notes is 0.50% per annum for the first $160.0 million of undrawn commitments and 0.75% per annum for the remaining $40.0 million of undrawn commitments, if any. The fee for undrawn commitments under the Class B notes is 0.50% per annum. The MyPower revolving credit facility is secured by the payments owed to us or our subsidiaries under MyPower customer loans and is non-recourse to our other assets.

Revolving Aggregation Credit Facility

On May 4, 2015, one of our subsidiaries entered into an agreement with a syndicate of banks for a revolving aggregation credit facility with a total committed amount of $500.0 million. On July 13, 2015, the total committed amount was increased to $650.0 million. The revolving aggregation credit facility bears interest at an annual rate of 2.75% plus (i) for commercial paper loans, the commercial paper rate and (ii) for LIBOR loans, at our option, three-month LIBOR or daily LIBOR. The revolving aggregation credit facility is secured by certain assets and cash flows of certain of our subsidiaries and is non-recourse to our other assets.

Solar Asset-backed Notes, Series 2015-1

In August 2015, we pooled and transferred our interests in certain financing funds into a SPE and issued $103.5 million in aggregate principal of Solar Asset-backed Notes, Series 2015-1, Class A, and $20.0 million in aggregate principal of Solar Asset-backed Notes, Series 2015-1, Class B, to certain investors. The Solar Asset-backed Notes, Series 2015-1, Class A, were issued at a discount of 0.05%, bear interest at 4.18% per annum and mature on August 21, 2045. The Solar Asset-backed Notes, Series 2015-1, Class B, were issued at a discount of 1.46%, bear interest at 5.58% per annum and mature on August 21, 2045. The SPE's assets and cash flows are not available to our other creditors, and the creditors of the SPE, including the Solar Asset-backed Note holders, have no recourse to our other assets.

Financing Fund Commitments

We have financing fund commitments from several fund investors that we can draw upon in the future upon the achievement of specific funding criteria. As of December 31, 2015, we had entered into 46 financing funds that had a total of $657.7 million of undrawn committed capital. From our significant customer backlog, we allocate to our financing funds leases, power purchase agreements and the related economic benefits associated with the solar energy systems, in accordance with the criteria of each fund. Upon such allocation and upon our satisfaction of the conditions precedent to drawing upon such commitments, we are able to draw down on the financing fund commitments. Once received, these proceeds provide working capital to deliver solar energy systems to our customers and form part of our general working capital.

Contractual Obligations

Set forth below is information concerning our contractual commitments and obligations as of December 31, 2015 (in thousands):

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term borrowings(1)	$2,753,746	$ 375,137	$1,295,328	$ 728,762	$ 354,519
Firm purchase commitments	237,387	191,033	24,150	6,274	15,930
Interest(2)	208,729	75,064	76,915	32,060	24,690
Lease obligations	280,764	57,791	96,990	49,343	76,640
Performance guarantee	3,126	3,126	—	—	—
Total	$3,483,752	$ 702,151	$1,493,383	$ 816,439	$ 471,779

(1) Included in the 2018, 2019 and 2020 long-term borrowings commitments are $230.0 million, $566.0 million and $113.0 million, respectively, related to convertible senior notes. These notes do not have a cash conversion option and are therefore expected to be settled in shares of our common stock.

(2) Represents obligations for interest payments on long-term borrowings and sale-leaseback financing obligations, and includes projected interest on variable-rate long-term borrowings based on interest rates as of December 31, 2015.

Off-Balance Sheet Arrangements

We include in our consolidated financial statements all assets, liabilities and results of operations of the financing fund arrangements that we have entered into. We have not entered into any other transactions that have generated relationships with unconsolidated entities, financial partnerships or SPEs. Accordingly, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

See Note 2, *Summary of Significant Accounting Policies and Procedures*, to our consolidated financial statements included elsewhere in this annual report on Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks as part of our ongoing business operations. Our primary exposures include changes in interest rates because certain borrowings bear interest at floating rates plus a specified margin. For fixed-rate debt, interest rate changes do not affect our earnings or cash flows. Conversely, for floating-rate debt, interest rate changes generally impact our earnings and cash flows, assuming other factors are held constant. Pursuant to our risk management policies, in certain cases, we utilize derivative instruments to manage some of our exposures to fluctuations in interest rates on certain floating-rate debt. We do not enter into any derivative instruments for trading or speculative purposes. In addition, we entered into capped call option agreements to reduce the potential dilution to holders of our common stock upon the conversion of our convertible senior notes.

Changes in economic conditions could result in higher interest rates, thereby increasing our interest expense and reducing our funds available for capital investments, operations or other purposes. In addition, we must use a substantial portion of our cash inflows to service our borrowings, which may affect our ability to make future acquisitions or capital expenditures. A hypothetical 10% change in our interest rates would have increased our interest expense for the year ended December 31, 2015 and 2014 by $2.3million and $0.9 million, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

SOLARCITY CORPORATION

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The supplementary data required by Item 8 is presented under Part II, Item 7 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
SolarCity Corporation

We have audited the accompanying consolidated balance sheets of SolarCity Corporation (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of SolarCity Corporation at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 10, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Los Angeles, California
February 10, 2016

SolarCity Corporation
Consolidated Balance Sheets
(In Thousands, Except Share Par Values)

	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 382,544	$ 504,383
Short-term investments	11,311	138,311
Restricted cash	39,864	20,875
Accounts receivable (net of allowances for doubtful accounts of $4,292 and $1,941 as of December 31, 2015 and December 31, 2014, respectively)	33,998	22,708
Rebates receivable (net of reserves of $2,207 and $7,860 as of December 31, 2015 and December 31, 2014, respectively)	11,545	30,021
Inventories	342,951	217,223
Deferred income tax asset	—	13,149
Prepaid expenses and other current assets	79,925	50,946
Total current assets	902,138	997,616
Solar energy systems, leased and to be leased – net	4,375,553	2,796,796
Property, plant and equipment – net	262,387	75,464
Build-to-suit lease asset under construction	284,500	26,450
Goodwill and intangible assets – net	517,109	539,557
MyPower customer notes receivable, net of current portion	488,461	34,544
MyPower deferred costs	215,708	13,147
Other assets	241,262	67,645
Total assets(1)	$ 7,287,118	$ 4,551,219
Liabilities and equity		
Current liabilities:		
Accounts payable	$ 364,973	$ 237,809
Distributions payable to noncontrolling interests and redeemable noncontrolling interests	26,769	8,552
Current portion of deferred U.S. Treasury grant income	15,336	15,330
Accrued and other current liabilities	270,184	152,408
Customer deposits	6,322	10,560
Current portion of deferred revenue	103,078	86,238
Current portion of long-term debt	180,048	11,781
Current portion of solar bonds	13,189	659
Current portion of solar bonds issued to related parties	165,120	330
Current portion of solar asset-backed notes	13,864	13,157
Current portion of financing obligation	34,479	29,689
Total current liabilities	1,193,362	566,513
Deferred revenue, net of current portion	1,010,491	557,408
Long-term debt, net of current portion	1,006,595	282,789
Solar bonds, net of current portion	35,678	2,463
Solar bonds issued to related parties, net of current portion	100	200
Convertible senior notes	881,585	777,726
Convertible senior notes issued to related parties	12,975	—
Solar asset-backed notes, net of current portion	395,667	293,215
Long-term deferred tax liability	1,373	13,194
Financing obligation, net of current portion	68,940	73,379
Deferred U.S. Treasury grant income, net of current portion	382,283	397,486
Build-to-suit lease liability	284,500	26,450
Other liabilities and deferred credits	279,006	218,024
Total liabilities(1)	5,552,555	3,208,847
Commitments and contingencies (Note 22)		
Redeemable noncontrolling interests in subsidiaries	320,935	186,788
Stockholders' equity:		
Common stock, $0.0001 par value - authorized, 1,000,000 shares as of December 31, 2015 and December 31, 2014; issued and outstanding, 97,864 and 96,521 shares as of December 31, 2015 and December 31, 2014, respectively	10	10
Additional paid-in capital	1,195,246	1,003,992
Accumulated deficit	(316,690)	(258,360)
Total stockholders' equity	878,566	745,642
Noncontrolling interests in subsidiaries	535,062	409,942
Total equity	1,413,628	1,155,584

Total liabilities and equity	$ 7,287,118	$ 4,551,219

(1) SolarCity Corporation's, or the Company's, consolidated assets as of December 31, 2015 and 2014 include $2,866,882 and $1,672,370, respectively, being assets of variable interest entities, or VIEs, that can only be used to settle obligations of the VIEs. These assets include solar energy systems, leased and to be leased - net of $2,779,363 and $1,581,459 as of December 31, 2015 and 2014, respectively; property, plant and equipment - net of $21,960 and $24,286 as of December 31, 2015 and 2014, respectively; cash and cash equivalents of $33,537 and $27,820 as of December 31, 2015 and 2014, respectively; inventory of $1,000 and $614 as of December 31, 2015 and 2014, respectively; restricted cash, current, of $522 and $106 as of December 31, 2015 and 2014, respectively; accounts receivable - net of $10,267 and $6,769 as of December 31, 2015 and 2014, respectively; prepaid expenses and other current assets of $2,713 and $1,839 as of December 31, 2015 and 2014, respectively; rebates receivable of $6,220 and $25,397 as of December 31, 2015 and 2014, respectively; restricted cash, long-term, of $254 and $300 as of December 31, 2015 and 2014, respectively; and other assets of $11,046 and $3,780 as of December 31, 2015 and 2014, respectively. The Company's consolidated liabilities as of December 31, 2015 and 2014 included $33,475 and $27,808, respectively, being liabilities of VIEs whose creditors have no recourse to the Company. These liabilities include distributions payable to noncontrolling interests in subsidiaries and redeemable noncontrolling interests in subsidiaries of $26,769 and $8,552 as of December 31, 2015 and 2014, respectively; accounts payable of $1,954 and $2,748 as of December 31, 2015 and 2014, respectively; customer deposits of $2,928 and $6,405 as of December 31, 2015 and 2014, respectively; accrued liabilities and other payables of $1,824 and $969 as of December 31, 2015 and 2014, respectively; and current portion of long-term debt of $0 and $9,134 as of December 31, 2015 and 2014, respectively.

See the further description in Note 3, *Acquisitions*, and Note 12, *VIE Fund Arrangements*.

See accompanying notes.

SolarCity Corporation
Consolidated Statements of Operations
(In Thousands, Except Share and Per Share Amounts)

	Year Ended December 31,		
	2015	2014	2013
Revenue:			
Operating leases and solar energy systems incentives	$ 293,543	$ 173,636	$ 82,856
Solar energy systems and components sales	106,076	81,395	80,981
Total revenue	399,619	255,031	163,837
Cost of revenue:			
Operating leases and solar energy systems incentives	165,546	92,920	32,745
Solar energy systems and components sales	115,245	83,512	91,723
Total cost of revenue	280,791	176,432	124,468
Gross profit	118,828	78,599	39,369
Operating expenses:			
Sales and marketing	457,185	238,608	97,426
General and administrative	244,508	156,426	89,801
Research and development	64,925	19,162	1,520
Total operating expenses	766,618	414,196	188,747
Loss from operations	(647,790)	(335,597)	(149,378)
Interest expense - net	91,939	55,758	25,738
Other expense - net	25,767	10,611	1,441
Loss before income taxes	(765,496)	(401,966)	(176,557)
Income tax (provision) benefit	(3,326)	26,736	24,799
Net loss	(768,822)	(375,230)	(151,758)
Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(710,492)	(319,196)	(95,968)
Net loss attributable to stockholders	$ (58,330)	$ (56,034)	$ (55,790)
Net loss attributable to common stockholders			
Basic	$ (58,330)	$ (56,034)	$ (55,790)
Diluted	$ (58,330)	$ (56,034)	$ (55,790)
Net loss per share attributable to common stockholders			
Basic	$ (0.60)	$ (0.60)	$ (0.70)
Diluted	$ (0.60)	$ (0.60)	$ (0.70)
Weighted-average shares used to compute net loss per share attributable to common stockholders			
Basic	97,200,925	93,333,880	79,781,976
Diluted	97,200,925	93,333,880	79,781,976

See accompanying notes.

SolarCity Corporation
Consolidated Statements of Equity
(In Thousands, Except Per Share Amounts)

	Common Stock		Additional Paid-In Capital	Accumulated Deficit	Total Stockholders' Equity (Deficit)	Noncontrolling Interests in Subsidiaries	Total Equity
	Shares	Amount					
Balance at January 1, 2013	74,913	$ 7	$ 330,130	$ (146,536)	$ 183,601	$ 96,793	$ 280,394
Contributions from noncontrolling interests	—	—	—	—	—	189,779	189,779
Issuance of common stock from a subsequent public offering, net of underwriting discounts and commissions and issuance costs of $7,888	3,910	1	174,082	—	174,083	—	174,083
Issuance of common stock upon acquisition of assets of Paramount Energy, net of issuance costs of $70	3,675	1	108,733	—	108,734	—	108,734
Issuance of common stock upon acquisition of Zep Solar	2,752	1	140,561	—	140,562	—	140,562
Issuance of common stock options upon acquisition of Zep Solar	—	—	14,893	—	14,893	—	14,893
Stock-based compensation expense	—	—	27,936	—	27,936	—	27,936
Issuance of common stock upon exercise of stock options for cash	4,260	—	15,545	—	15,545	—	15,545
Issuance of common stock upon vesting of restricted stock units	14	—	—	—	—	—	—
Issuance of common stock upon exercise of stock warrants for cash	1,485	—	8,034	—	8,034	—	8,034
Net (loss) income	—	—	—	(55,790)	(55,790)	22,886	(32,904)
Distributions to noncontrolling interests	—	—	—	—	—	(122,641)	(122,641)
Balance at December 31, 2013	91,009	$ 10	$ 819,914	$ (202,326)	$ 617,598	$ 186,817	$ 804,415
Contributions from noncontrolling interests	—	—	—	—	—	517,471	517,471
Issuance of common stock upon acquisition of Silevo	2,284	—	137,958	—	137,958	—	137,958
Issuance of restricted stock units upon acquisition of Silevo	—	—	132	—	132	—	132
Purchase of capped call options	—	—	(65,203)	—	(65,203)		(65,203)
Stock-based compensation expense	—	—	88,936	—	88,936	—	88,936
Issuance of common stock upon exercise of stock options for cash	3,176	—	20,255	—	20,255	—	20,255
Issuance of common stock upon vesting of restricted stock units	52	—	—	—	—		—
Acquisition of noncontrolling interest in subsidiaries	—	—	2,000	—	2,000	—	2,000
Net loss	—	—	—	(56,034)	(56,034)	(178,124)	(234,158)
Transfers to redeemable noncontrolling interests in subsidiaries	—	—	—	—	—	(25,248)	(25,248)
Distributions to noncontrolling interests	—	—	—	—	—	(90,974)	(90,974)
Balance at December 31, 2014	96,521	$ 10	$1,003,992	$ (258,360)	$ 745,642	$ 409,942	$1,155,584
Contributions from noncontrolling interests	—	—	—	—	—	681,994	681,994
Tax benefit of stock option exercises	—	—	63,019	—	63,019	—	63,019
Stock-based compensation expense	—	—	116,585	—	116,585	—	116,585
Issuance of common stock upon exercise of stock options for cash	951	—	11,650	—	11,650	—	11,650
Issuance of common stock to employees and board members upon vesting of restricted stock units	392	—	—	—	—	—	—
Net loss	—	—	—	(58,330)	(58,330)	(451,999)	(510,329)
Distributions to noncontrolling interests	—	—	—	—	—	(104,875)	(104,875)
Balance at December 31, 2015	97,864	$ 10	$1,195,246	$ (316,690)	$ 878,566	$ 535,062	$1,413,628

See accompanying notes.

SolarCity Corporation
Consolidated Statements of Cash Flows
(In Thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating activities:			
Net loss	$ (768,822)	$ (375,230)	$ (151,758)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation and amortization	166,653	97,880	41,448
Non cash interest and other expense	16,427	13,631	13,438
Stock-based compensation, net of amounts capitalized	86,369	65,562	21,262
Tax benefit of stock option exercises	(63,019)	—	—
Loss on extinguishment of long-term debt	1,093	4,533	306
Deferred income taxes	(527)	(26,680)	(25,424)
Non-cash reduction in financing obligation	(48,132)	(48,837)	(35,675)
Loss on disposal of property, plant and equipment and construction in progress	3,840	1,404	60
Changes in operating assets and liabilities:			
Restricted cash	(48,650)	(17,699)	(13,059)
Accounts receivable	(11,049)	945	2,911
Rebates receivable	18,476	(9,890)	(2,630)
Inventories	(125,337)	(97,347)	(19,954)
Prepaid expenses and other current assets	(24,485)	(23,155)	(19,276)
MyPower deferred costs	(202,899)	(13,571)	—
Other assets	(70,016)	(18,872)	(6,882)
Accounts payable	125,472	112,480	50,750
Accrued and other liabilities	147,455	(22,676)	84,444
Customer deposits	(4,238)	1,732	919
Deferred revenue	11,505	137,941	233,635
Net cash (used in) provided by operating activities	(789,884)	(217,849)	174,515
Investing activities:			
Payments for the cost of solar energy systems, leased and to be leased	(1,665,641)	(1,162,963)	(716,947)
Purchase of property, plant and equipment	(176,540)	(22,892)	(9,126)
Purchases of short-term investments	(44,592)	(167,397)	—
Proceeds from sales and maturities of short-term investments	170,737	28,764	—
Acquisition of business, net of cash acquired	(9,509)	1,874	(3,826)
Other investments	(1,189)	(22,200)	—
Net cash used in investing activities	(1,726,734)	(1,344,814)	(729,899)

	Year Ended December 31,		
	2015	2014	2013
Financing activities:			
Investment fund financings, bank and other borrowings:			
Borrowings under long-term debt	1,093,261	369,801	203,228
Repayments of long-term debt	(215,933)	(336,557)	(65,328)
Proceeds from issuance of solar bonds	47,146	3,122	—
Proceeds from issuance of solar bonds issued to related parties	165,020	530	—
Repayments of borrowings under solar bonds	(1,820)	—	—
Repayments of borrowings under solar bonds issued to related parties	(330)	—	—
Proceeds from issuance of solar asset-backed notes	119,790	262,880	51,334
Repayments of borrowings under solar asset-backed notes	(15,863)	(5,932)	(1,461)
Payment of deferred purchase consideration	(3,747)	(2,206)	(3,382)
Proceeds from financing obligation	43,125	44,563	57,780
Repayments of financing obligation	(5,259)	(12,460)	(41,536)
Repayment of capital lease obligations	(6,036)	(2,772)	(1,594)
Proceeds from investment by noncontrolling interests and redeemable noncontrolling interests in subsidiaries	1,097,487	777,963	362,692
Distributions paid to noncontrolling interests and redeemable noncontrolling interests in subsidiaries	(109,511)	(117,125)	(137,005)
Proceeds from U.S. Treasury grants	—	342	127,476
Net cash provided by financing activities before equity and convertible notes issuances	2,207,330	982,149	552,204
Equity and convertible notes issuances:			
Proceeds from issuance of common stock	—	—	174,083
Proceeds from issuance of convertible senior notes	99,805	552,765	222,518
Proceeds from issuance of convertible senior notes issued to related parties	12,975	—	—
Purchase of capped call options	—	(65,203)	—
Proceeds from exercise of stock options	11,650	20,255	15,545
Tax benefit of stock option exercises	63,019	—	—
Proceeds from exercise of common stock warrants	—	—	8,034
Net cash provided by equity issuances	187,449	507,817	420,180
Net cash provided by financing activities	2,394,779	1,489,966	972,384
Net (decrease) increase in cash and cash equivalents	(121,839)	(72,697)	417,000
Cash and cash equivalents, beginning of period	504,383	577,080	160,080
Cash and cash equivalents, end of period	$ 382,544	$ 504,383	$ 577,080
Supplemental disclosures of cash flow information:			
Cash paid during the period for interest	$ 53,971	$ 22,702	$ 6,603
Cash paid during the period for taxes, net of refunds	$ 2,846	$ 1,881	$ (1,726)

See accompanying notes.

SolarCity Corporation
Notes to Consolidated Financial Statements

1. Organization

SolarCity Corporation, or the Company, was incorporated as a Delaware corporation on June 21, 2006. The Company is engaged in the design, manufacture, installation and sale or lease of solar energy systems to residential and commercial customers, or sale of electricity generated by solar energy systems to customers. The Company's headquarters are located in San Mateo, California.

2. Summary of Significant Accounting Policies and Procedures

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles, or GAAP, and reflect the accounts and operations of the Company and those of its subsidiaries in which the Company has a controlling financial interest. In accordance with the provisions of Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, 810, *Consolidation*, the Company consolidates any variable interest entity, or VIE, of which it is the primary beneficiary. The Company forms VIEs with its financing fund investors in the ordinary course of business in order to facilitate the funding and monetization of certain attributes associated with its solar energy systems. The typical condition for a controlling financial interest ownership is holding a majority of the voting interests of an entity; however, a controlling financial interest may also exist in entities, such as VIEs, through arrangements that do not involve controlling voting interests. ASC 810 requires a variable interest holder to consolidate a VIE if that party has the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. The Company does not consolidate a VIE in which it has a majority ownership interest when the Company is not considered the primary beneficiary. The Company has determined that it is the primary beneficiary of a number of VIEs (see Note 3, *Acquisitions*, and Note 12, *VIE Arrangements*). The Company evaluates its relationships with all the VIEs on an ongoing basis to ensure that it continues to be the primary beneficiary. All intercompany transactions and balances have been eliminated in consolidation.

The Company and its subsidiaries' fiscal quarters and years are the same as calendar quarters and years except for Silevo, Inc. and its subsidiaries, or Silevo, which continues to have fiscal quarters based on 13-week periods and fiscal years based on 52-week periods. For 2015, Silevo's fiscal year ended on December 26, 2015, and this timing difference and the related activity did not materially impact the consolidated financial statements.

Reclassifications

Certain prior period balances have been reclassified to conform to the current period presentation. In addition, as a result of the Company's adoption of Accounting Standards Update, or ASU, No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs* (see below), the Company reclassified deferred financing costs from assets and presented the balances as an offset against the associated debt. The impact of the Company's adoption of the ASU on the prior period consolidated balance sheet was as follows (in thousands):

	December 31, 2014		
	As Previously Reported	Adoption of ASU	As Reclassified
Prepaid expenses and other current assets	$ 55,729	$ (4,783)	$ 50,946
Other assets	$ 97,854	$ (30,209)	$ 67,645
Current portion of solar bonds	$ 1,150	$ (161)	$ 989
Current portion of solar asset-backed notes	$ 13,574	$ (417)	$ 13,157
Long-term debt, net of current portion	$ 287,621	$ (4,832)	$ 282,789
Solar bonds, net of current portion	$ 2,793	$ (130)	$ 2,663
Convertible senior notes	$ 796,000	$ (18,274)	$ 777,726
Solar asset-backed notes, net of current portion	$ 304,393	$ (11,178)	$ 293,215

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Use of Estimates

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and the accompanying notes. Management regularly makes significant estimates and assumptions regarding the selling price of undelivered elements for revenue recognition purposes, the collectability of accounts and rebates receivable, the valuation of inventories, the labor costs for long-term contracts used as a basis for determining the percentage of completion for such contracts, the fair values and residual values of solar energy systems subject to leases, the accounting for business combinations, the fair values and useful lives of acquired tangible and intangible assets, the fair value of debt assumed under business combinations, the fair value of contingent consideration payable under business combinations, the fair value of short-term investments, the useful lives of solar energy systems, property, plant and equipment, the determination of accrued warranty, the determination of accrued liability for solar energy system performance guarantees, the determination of lease pass-through financing obligations, the discount rates used to determine the fair values of investment tax credits, the valuation of stock-based compensation, the determination of valuation allowances associated with deferred tax assets, asset impairment, the valuation of build-to-suit lease assets, the fair value of interest rate swaps and other items. Management bases its estimates on historical experience and on various other assumptions believed to be reasonable, the results of which form the basis for making judgments about the carrying values of assets and liabilities. Actual results could differ materially from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The Company maintains cash and cash equivalents, which consist principally of demand deposits with high-credit-quality financial institutions. The Company has exposure to credit risk to the extent cash and cash equivalent balances, including any restricted cash balances on deposit, exceed amounts covered by federal deposit insurance. The Company believes that its credit risk is not significant.

Short-Term Investments

The Company's short-term investments are comprised of corporate debt securities and asset-backed securities. The Company classifies short-term investments as available-for-sale and carries them at fair value, with any unrealized gains or losses recognized as other comprehensive income or loss in the consolidated balance sheet. The specific identification method is used to determine the cost of any securities disposed of, with any realized gains or losses recognized as other income or expense in the consolidated statement of operations. Short-term investments are anticipated to be used for current operations and are, therefore, classified as current assets even though their maturities may extend beyond one year. The Company periodically reviews short-term investments for impairment. In the event a decline in value is determined to be other-than-temporary, an impairment loss is recognized. When determining if a decline in value is other-than-temporary, the Company takes into consideration the current market conditions and the duration and severity of and the reason for the decline, as well as the likelihood that it would need to sell the security prior to a recovery of par value.

As of December 31, 2015, short-term investments were comprised of $9.3 million of corporate debt securities and $2.0 million of asset-backed securities. As of December 31, 2014, short-term investments were comprised of $126.2 million of corporate debt securities and $12.1 million of asset-backed securities.

The costs of these securities approximated their fair values, and there were no material gross realized or unrealized gains, gross realized or unrealized losses or impairment losses recognized for the years ended December 31, 2015, 2014 or 2013. As of December 31, 2015, all short-term investments were scheduled to mature within the next 12 months.

Restricted Cash

Restricted cash includes cash received from certain fund investors that had not been released for use by the Company, cash held to service certain payments under various secured debt facilities, including management fee, principal and interest payments, and balances collateralizing outstanding letters of credit, outstanding credit card borrowing facilities and obligations under certain operating leases.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Accounts Receivable

Accounts receivable primarily represent trade receivables from billings and sales to residential and commercial customers recorded at net realizable value. The Company maintains an allowance for doubtful accounts to reserve for potentially uncollectible accounts receivable. The Company reviews its accounts receivable by aging category to identify significant customer balances with known disputes or collection issues. In determining the allowance, the Company makes judgments about the creditworthiness of a majority of its customers based on ongoing credit evaluations. The Company also considers its historical level of credit losses and current economic trends that might impact the level of future credit losses. The Company writes off accounts receivable when they are deemed uncollectible.

Customer Notes Receivable

In the fourth quarter of 2014, the Company launched MyPower, a program that offers residential customers the option to finance the purchase of solar energy systems through a 30-year loan provided by a wholly owned subsidiary of the Company. In order to qualify for a loan, a customer must pass the Company's credit evaluation process, and the loans are secured by the solar energy systems financed. The outstanding loan balances, net of any allowance for potentially uncollectible amounts, are presented on the consolidated balance sheets as a component of prepaid expenses and other current assets for the current portion and as customer notes receivable, net of current portion, for the long-term portion. In determining the allowance and credit quality for customer loans under MyPower, the Company identifies significant customers with known disputes or collection issues and also considers its historical level of credit losses and current economic trends that might impact the level of future credit losses. Customer notes receivable that are individually impaired are charged-off as a write-off of allowance for losses. As of December 31, 2015 and 2014, there were no significant customers with known disputes or collection issues, and the amount of potentially uncollectible amounts was insignificant. Accordingly, the Company did not establish an allowance for losses against customer notes receivable. In addition, there were no material non-accrual or past due customer notes receivable as of December 31, 2015 and 2014.

Rebates Receivable

Rebates receivable represent rebates due from utility companies and government agencies. These receivables include rebates that have been assigned to the Company by its cash customers on state-approved solar energy system installations sold to the customers and also uncollected incentives from state and local government agencies for solar energy system installations that have been leased to customers or are used to generate and sell electricity to customers under power purchase agreements. For the rebates assigned to the Company by its customers, the Company assumes the responsibility for the application and collection of the rebate. The processing cycle for these rebates and incentives involves a multi-step process in which the Company accumulates and submits information required by the utility company or state agency necessary for the collection of the rebate. The entire process typically can take up to several months to complete. The Company recognizes rebates receivable upon the solar energy system passing inspection by the utility or authority having jurisdiction after completion of system installation. The Company maintains an allowance to reserve for potentially uncollectible rebates. In determining the allowance, the Company makes judgments based on the length of period that a rebate amount has been outstanding and reasons for the delays in collecting the rebate.

Interest Rate Swaps

In 2015, the Company began entering into fixed-for-floating interest rate swap agreements to reduce the potential impact of future changes in interest rates on certain variable rate debt. All interest rate swaps are recognized at fair value on the consolidated balance sheets within other assets or other liabilities and deferred credits, with any changes in fair value recognized as other income or expense in the consolidated statements of operations. The Company has not designated any interest rate swaps as hedging instruments. As of and for the year ended December 31, 2015, the Company had interest rate swaps outstanding as follows (in thousands):

Aggregate Notional Amount	Gross Liability at Fair Value	Gross Losses Year Ended December 31, 2015

Interest rate swaps	$ 640,628	$ 11,544	$ 11,544

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Concentrations of Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of cash and cash equivalents, short-term investments, accounts receivable, customer notes receivable, rebates receivable and interest rate swaps. The associated risk of concentration for cash and cash equivalents is mitigated by banking with creditworthy institutions. At certain times, amounts on deposit exceed federal deposit insurance limits. The associated risk of concentration for short-term investments is mitigated by holding a diversified portfolio of highly rated short-term investments. The associated risk of concentration for accounts receivable and customer notes receivable is mitigated by placing liens on the related solar energy systems and performing periodic and ongoing credit evaluations of the Company's customers. Rebates receivable are due from various states and local governments as well as various utility companies. The associated risk of concentration for interest rate swaps is mitigated by transacting with several highly rated multinational banks. The Company maintains reserves for any amounts that it considers to be uncollectable.

Fair Value of Financial Instruments

ASC 820, *Fair Value Measurements*, clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability.

ASC 820 requires that the valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. ASC 820 establishes a three-tier fair value hierarchy, which prioritizes inputs that may be used to measure fair value as follows:

- Level 1—Observable inputs that reflect quoted prices for identical assets or liabilities in active markets.
- Level 2—Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.
- Level 3—Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

As of December 31, 2015 and 2014, the assets and liabilities carried at fair value on a recurring basis included cash equivalents, short-term investments, interest rate swaps and contingent consideration (see Note 3, *Acquisitions*). As of December 31, 2015, the fair value of the Company's cash equivalents, short-term investments, interest rate swaps and contingent consideration were as follows (in thousands):

	Level 1	Level 2	Level 3
Cash equivalents:			
Money market funds	$ 69,080	$ —	$ —
Short-term investments:			
Corporate debt securities	$ —	$ 9,311	$ —
Asset-backed securities	$ —	$ 2,000	$ —
Liabilities:			
Interest rate swaps	$ —	$ 11,544	$ —
Contingent consideration	$ —	$ —	$ 123,008

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

As of December 31, 2014, the fair value of the Company's cash equivalents, short-term investments and contingent consideration were as follows (in thousands):

	Level 1	Level 2	Level 3
Cash equivalents:			
Money market funds	$ 54,229	$ —	$ —
Corporate debt securities	$ —	$ 7,599	$ —
Short-term investments:			
Corporate debt securities	$ —	$ 126,159	$ —
Asset-backed securities	$ —	$ 12,152	$ —
Liabilities:			
Contingent consideration	$ —	$ —	$ 117,197

The Company classified its money market funds within Level 1 because their fair values are based on their quoted market prices. The Company classified its corporate debt securities, asset-backed securities and interest rate swaps within Level 2 because their fair values are determined using alternative pricing sources or models that utilized market observable inputs, including current and forward interest rates, to determine their fair values. The Company classified its contingent consideration within Level 3 because its fair value is determined using unobservable probability estimates and unobservable estimated discount rates applicable to the acquisition. During the years ended December 31, 2015 and 2014, there were no transfers between the levels of the fair value hierarchy.

The contingent consideration is dependent on the achievement of the specified production milestones for the acquired business, as discussed in Note 3, *Acquisitions*. The Company determined the fair value of the contingent consideration using a probability-weighted expected return methodology that considers the timing and probabilities of achieving these milestones and uses discount rates that reflect the appropriate cost of capital. The Company reassesses the valuation assumptions each reporting period, with any changes in the fair value accounted for in the consolidated statement of operations. The fair value of the contingent consideration is directly proportional to the estimated probabilities of achieving these milestones. As of December 31, 2015, the estimated probabilities ranged from 90% to 95%, the estimated discount rates ranged from 5.0% to 7.0%, $42.9 million was included under accrued and other current liabilities on the consolidated balance sheets and $80.1 million was included under other liabilities and deferred credits on the consolidated balance sheets. As of December 31, 2014, the estimated probabilities ranged from 90% to 95%, the estimated discount rates ranged from 5.0% to 7.0%, $42.0 million was included under accrued and other current liabilities on the consolidated balance sheets and $75.2 million was included under other liabilities and deferred credits on the consolidated balance sheets. The following table summarizes the activity of the Level 3 contingent consideration balance for the years ended December 31, 2015 and 2014 (in thousands):

Balance at January 1, 2014	$ —
Acquisition of Silevo	115,319
Change in fair value recorded in other expense - net	1,878
Balance at December 31, 2014	117,197
Change in fair value recorded in other expense - net	5,811
Balance at December 31, 2015	$ 123,008

The Company's financial instruments that are not re-measured at fair value include accounts receivable, customer notes receivable, rebates receivable, accounts payable, customer deposits, distributions payable to noncontrolling interests and redeemable noncontrolling interests, the participation interest, solar asset-backed notes, convertible senior notes, Solar Bonds and long-term debt. The carrying values of these financial instruments other than customer notes receivable, the participation interest, solar asset-backed notes, convertible senior notes, Solar Bonds and long-term debt approximated their fair values due to the fact that they were short-term in nature at December 31, 2015 and 2014 (Level 1).

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

The Company estimates the fair value of convertible senior notes based on their last actively traded prices (Level 1). The Company estimates the fair value of customer notes receivable, the participation interest, solar asset-backed notes, Solar Bonds and long-term debt based on rates currently offered for instruments with similar maturities and terms (Level 3). The following table presents their estimated fair values and their carrying values (in thousands):

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Participation interest	$ 15,919	$ 14,525	$ 15,556	$ 14,102
Solar asset-backed notes	$ 409,531	$ 432,797	$ 306,372	$ 328,313
Convertible senior notes	$ 894,560	$ 842,752	$ 777,726	$ 752,176
MyPower customer notes receivable	$ 493,510	$ 493,510	$ 35,645	$ 35,645
Long-term debt	$ 1,186,643	$ 1,186,643	$ 294,570	$ 294,570
Solar bonds	$ 214,087	$ 214,087	$ 3,652	$ 3,652

Business Combinations

The Company accounts for business acquisitions under ASC 805, *Business Combinations*. The cost of an acquisition is measured at the fair value of the assets given, equity instruments issued and liabilities assumed at the acquisition date. Costs that are directly attributable to the acquisition are expensed as incurred. Identifiable assets, including intangible assets, acquired and liabilities, including contingent liabilities, assumed in the acquisition are measured initially at their fair values at the acquisition date. Any noncontrolling interests in the acquired business are also initially measured at fair value. The Company recognizes goodwill if the aggregate fair value of the total purchase consideration and the noncontrolling interests is in excess of the aggregate fair value of the identifiable assets acquired and the liabilities assumed.

Goodwill

Goodwill represents the difference between the purchase price and the aggregate fair value of the identifiable assets acquired and the liabilities assumed in a business combination. The Company assesses goodwill impairment annually, in the fourth quarter of each fiscal year, and whenever events or changes in circumstances indicate that the carrying value of goodwill may exceed its fair value at the consolidated-level, which is the sole reporting unit. When assessing goodwill for impairment, the Company considers its market capitalization adjusted for a control premium and, if necessary, the Company's discounted cash flow model, which involves significant assumptions and estimates, including the Company's future financial performance, weighted-average cost of capital and interpretation of currently enacted tax laws. Circumstances that could indicate impairment and require the Company to perform an impairment test include a significant decline in the Company's financial results, a significant decline in the Company's market capitalization relative to its net book value, an unanticipated change in competition or the Company's market share and a significant change in the Company's strategic plans.

Inventories

Inventories include raw materials that include silicon wafers, process gasses, chemicals and other consumables used in solar cell production, solar cells, photovoltaic panels, inverters, mounting hardware and miscellaneous electrical components. Inventories also include work in process that includes raw materials partially installed and direct and indirect capitalized installation costs. Raw materials and work in process are stated at the lower of cost or market (generally on a first-in-first-out basis). Work in process primarily relates to solar energy systems that will be sold to customers, which are under construction and have yet to pass inspection.

The Company also evaluates its inventory reserves on a quarterly basis and writes down the value of inventories for estimated excess and obsolete inventories based upon assumptions about future demand and market conditions.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Solar Energy Systems, Leased and To Be Leased

The Company is the operating lessor of the solar energy systems under leases that qualify as operating leases. The Company accounts for the leases in accordance with ASC 840, *Leases*. To determine lease classification, the Company evaluates lease terms to determine whether there is a transfer of ownership or bargain purchase option at the end of the lease, whether the lease term is greater than 75% of the useful life, or whether the present value of minimum lease payments exceed 90% of the fair value at lease inception. The Company utilizes periodic appraisals to estimate useful life and fair values at lease inception, and residual values at lease termination. Solar energy systems are stated at cost, less accumulated depreciation.

Depreciation and amortization is calculated using the straight-line method over the estimated useful lives of the respective assets as follows.

	Useful Lives
Solar energy systems leased to customers	30 years
Initial direct costs related to customer solar energy system lease acquisition costs	Lease term (10 to 20 years)

Solar energy systems held for lease to customers are installed systems pending interconnection with the respective utility companies and will be depreciated as solar energy systems leased to customers when the respective systems have been interconnected and placed in service.

Solar energy systems under construction represents systems that are under installation, which will be depreciated as solar energy systems leased to customers when the respective systems are completed, interconnected and subsequently leased to customers.

Initial direct costs related to customer solar energy system lease acquisition costs are capitalized and amortized over the term of the related customer lease agreements.

Presentation of Cash Flows Associated with Solar Energy Systems

The Company classifies cash flows associated with solar energy systems in accordance with ASC 230, *Statement of Cash Flows*. The Company determines the appropriate classification of cash payments related to solar energy systems depending on the activity that is likely to be the predominant source of cash flows for the item being paid for. Accordingly, the Company presents payments made in a period for costs incurred to install solar energy systems that will be leased to customers, including the payments for cost of the inventory that is utilized in such systems, as investing activities in the consolidated statement of cash flows. Payments made for inventory that will be utilized for solar energy systems that will be sold to customers are presented as cash flows from operations in the consolidated statement of cash flows.

Property, Plant and Equipment

Property, plant and equipment, including leasehold improvements, are stated at cost, less accumulated depreciation and amortization.

Depreciation and amortization is calculated using the straight-line method over the estimated useful lives of the respective assets as follows.

	Useful Lives
Furniture and fixtures	3-7 years
Vehicles	5 years
Computer hardware and software	3-10 years
Manufacturing & lab equipment	2 to 3 years

Buildings	20 years
Land use rights	50 years

Leasehold improvements are amortized over the shorter of the lease term or their estimated useful lives, currently seven years.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Repairs and maintenance costs are expensed as incurred.

Upon disposition, the cost and related accumulated depreciation of the assets are removed from property, plant and equipment and the resulting gain or loss is reflected in the consolidated statements of operations.

Long-Lived Assets

The Company's long-lived assets include property, plant and equipment, solar energy systems, leased and to be leased, and intangible assets acquired through business combinations. Intangible assets with definite useful lives are amortized over their estimated useful lives, which range from one to 30 years.

Furthermore, the Company is deemed to be the owner, for accounting purposes, during the construction phase of certain long-lived assets under build-to-suit lease arrangements because of its involvement with the construction, its exposure to any potential cost overruns and its other commitments under the arrangements. In these cases, the Company recognizes a build-to-suit lease asset under construction and a corresponding build-to-suit lease liability on the consolidated balance sheets.

In accordance with ASC 360, *Property, Plant, and Equipment*, the Company evaluates long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of a long-lived asset, or group of assets, as appropriate, may not be recoverable. If the aggregate undiscounted future net cash flows expected to result from the use and the eventual disposition of a long-lived asset is less than its carrying value, then the Company would recognize an impairment loss based on the discounted future net cash flows. No impairment charges were recorded for the years ended December 31, 2015, 2014 or 2013.

Capitalization of Software Costs

For costs incurred in development of internal use software, the Company capitalizes costs incurred during the application development stage. Costs related to preliminary project activities and post implementation activities are expensed as incurred. Internal-use software is amortized on a straight-line basis over its estimated useful life of five to 10 years. The Company evaluates the useful lives of these assets on an annual basis and tests for impairment whenever events or changes in circumstances occur that could impact the recoverability of these assets.

Warranties

The Company provides a warranty on the installation and components of the solar energy systems it sells, including sales under MyPower contracts, for periods typically between 10 to 30 years. The manufacturer's warranty on the solar energy systems' components, which is typically passed-through to customers, ranges from one to 25 years. However, for the solar energy systems under lease contracts or power purchase agreements, the Company does not accrue a warranty liability because those systems are owned by subsidiaries that the Company consolidates. Instead, any repair costs on those solar energy systems are expensed when they are incurred as a component of operating leases and solar energy systems incentives cost of revenue. The changes in the accrued warranty balance, recorded as a component of accrued and other current liabilities on the consolidated balance sheets, consisted of the following (in thousands):

	As of and for the Year Ended December 31,	
	2015	2014
Balance - beginning of the period	$ 8,607	$ 7,502
Increase in liability (including $16,983 related to MyPower contracts)	18,929	2,022
Change in estimate	(4,282)	(468)
Less warranty claims	(261)	(449)

Balance - end of the period	$ 22,993	$ 8,607

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Solar Energy Systems Performance Guarantees

The Company guarantees certain specified minimum solar energy production output for certain systems leased or sold to customers generally for a term of up to 30 years. The Company monitors the solar energy systems to ensure that these outputs are being achieved. The Company evaluates if any amounts are due to its customers and makes any payments periodically as specified in the customer contracts. As of December 31, 2015 and 2014, the Company had recorded liabilities of $3.1 million and $1.6 million, respectively, under accrued and other current liabilities in the consolidated balance sheets, relating to these guarantees based on the Company's assessment of its current exposure.

Deferred U.S. Treasury Grants Income

The Company is eligible for U.S. Treasury grants received or receivable on eligible property as defined under Section 1603 of the American Recovery and Reinvestment Act of 2009, as amended by the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of December 2010, which includes solar energy system installations, upon approval by the U.S. Treasury Department. However, to be eligible for U.S. Treasury grants, a solar energy system must have commenced construction in 2011 either physically or through the incurrence of sufficient project costs. For solar energy systems under lease pass-through fund arrangements, as described in Note 13, *Lease Pass-Through Financing Obligation*, the Company reduces the financing obligation and records deferred income for the U.S. Treasury grants which are paid directly to the investors upon receipt of the grants by the investors. The benefit of the U.S. Treasury grants is recorded as deferred income and is amortized on a straight-line basis over the estimated useful lives of the related solar energy systems of 30 years. The amortization of the deferred income is recorded as a reduction to depreciation expense, which is a component of the cost of revenue of operating leases and solar energy systems incentives in the consolidated statements of operations. A catch-up adjustment is recorded in the period in which the grant is approved by the U.S. Treasury Department or received by lease pass-through investors to recognize the portion of the grant that matches proportionally the amortization for the period between the date of placement in service of the solar energy systems and approval by the U.S. Treasury Department or receipt by lease pass-through investors of the associated grant. The changes in deferred U.S. Treasury grants income were as follows (in thousands):

Balance at January 1, 2013	$ 298,260
U.S. Treasury grants received and receivable	124,404
U.S. Treasury grants received by investors under lease pass-through fund arrangements	20,599
Amortized as a credit to depreciation expense	(15,454)
Balance at December 31, 2013	427,809
U.S. Treasury grants received and receivable	342
Amortized as a credit to depreciation expense	(15,335)
Balance at December 31, 2014	412,816
U.S. Treasury grants received and receivable	144
Amortized as a credit to depreciation expense	(15,341)
Balance at December 31, 2015	$ 397,619

Of the balance outstanding as of December 31, 2015 and 2014, $382.3 million and $397.5 million, respectively, are classified as noncurrent deferred U.S. Treasury grants income in the consolidated balance sheets.

Deferred Investment Tax Credits Revenue

The Company's solar energy systems are eligible for investment tax credits, or ITCs, that accrue to eligible property under the Internal Revenue Code of 1986, as amended, or IRC. Under Section 50(d)(5) of the IRC and the related regulations, a lessor of qualifying property may elect to treat the lessee as the owner of such property for the purposes of claiming government ITCs associated with such property. These regulations enable the ITCs to be separated from the ownership of the property and allow the transfer of these ITCs. Under the lease pass-through fund arrangements, the Company can make a tax election to pass through the ITCs to the fund investor, who is the legal lessee of the property. The Company is therefore able to monetize the ITCs to investors who can utilize them in return for cash payments. The Company considers the monetization of ITCs to constitute one of the key elements of realizing the value associated with

solar energy systems. The Company therefore views the proceeds from the monetization of ITCs to be a component of revenue generated from the solar energy systems.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

For the lease pass-through fund arrangements, the Company allocates a portion of the aggregate payments received from the investor to the estimated fair value of the assigned ITCs and the balance to the future customer lease payments that are also assigned to the investors. The estimated fair value of the ITCs are determined by discounting the estimated cash flow impact of the ITCs using an appropriate discount rate that reflects a market interest rate.

The Company recognizes the revenue associated with the monetization of ITCs in accordance with ASC 605-10-S99, *Revenue Recognition-Overall-SEC Materials*. The revenue associated with the monetization of the ITCs is recognized when (1) persuasive evidence of an arrangement exists, (2) delivery has occurred or services have been rendered, (3) the sales price is fixed or determinable and (4) collection of the related receivable is reasonably assured. The ITCs are subject to recapture under the IRC if the underlying solar energy system either ceases to be a qualifying property or undergoes a change in ownership within five years of its placed in service date. The recapture amount decreases on the anniversary of the placed in service date. As the Company has an obligation to ensure the solar energy system is in service and operational for a term of five years to avoid any recapture of the ITCs, the Company recognizes revenue as the recapture provisions lapse assuming the other aforementioned revenue recognition criteria have been met. The monetized ITCs are initially recorded as deferred revenue on the consolidated balance sheet, and subsequently, one-fifth of the monetized ITCs is recognized as revenue from operating leases and solar energy systems incentives in the consolidated statement of operations on each anniversary of the solar energy system's placed in service date over the next five years.

The Company guarantees its financing fund investors that in the event of a subsequent recapture of the ITCs by the taxing authority due to the Company's noncompliance with the applicable ITC guidelines, the Company will compensate the investor for any recaptured credits. The Company has concluded that the likelihood of a recapture event is remote and consequently has not recorded any liability in the consolidated financial statements for any potential recapture exposure.

Current deferred investment tax credits revenue, which is included as a part of current portion of deferred revenue in the consolidated balance sheets, as of December 31, 2015 and 2014 was $51.8 million and $47.9 million, respectively. Noncurrent deferred investment tax credits revenue, which is included as a part of deferred revenue, net of current portion, in the consolidated balance sheets, as of December 31, 2015 and 2014 was $130.8 million and $163.0 million, respectively. For the years ended December 31, 2015, 2014 and 2013, the Company recognized $47.9 million, $28.2 million and $0.5 million, respectively, of revenue related to the monetization of ITCs, which is included in operating leases and solar energy systems incentives revenue in the consolidated statements of operations.

Deferred Revenue

The Company records as deferred revenue any amounts that are collected from customers, including lease prepayments, in excess of revenue recognized. Deferred revenue also includes the portion of rebates and incentives received from utility companies and various local and state government agencies, which are recognized as revenue over the lease term, as well as the remote monitoring fee (discussed below), which is recognized as revenue ratably over the respective customer contract term. As of December 31, 2015 and 2014, deferred revenue related to customer payments, which is included in the deferred revenue balances on the consolidated balance sheets, amounted to $289.3 million and $229.5 million, respectively. As of December 31, 2015 and 2014, deferred revenue from rebates and incentives, which is included in the deferred revenue balances on the consolidated balance sheets, amounted to $186.1 million and $169.6 million, respectively. In addition, under MyPower customer contracts (discussed below), all initial revenue associated with financed sales of solar energy systems are also recorded as a component of the deferred revenue balances on the consolidated balance sheets. As of December 31, 2015 and 2014, current deferred revenue from MyPower contracts, which is included in current portion of deferred revenue in the consolidated balance sheets, amounted to $4.6 million and $1.0 million, respectively. As of December 31, 2015 and 2014, noncurrent deferred revenue from MyPower contracts, which is included in deferred revenue, net of current portion, in the consolidated balance sheets, amounted to $448.2 million and $32.7 million, respectively. As of December 31, 2015 and 2014, current portion of deferred revenue included $2.8 million and $0.0 million, respectively, related to accrued interest on MyPower customer notes receivable.

Revenue Recognition

The Company's customers purchase solar energy systems from the Company under fixed-price contracts or lease Company-owned solar energy systems that also include remote monitoring services. A residential customer that purchases

a solar energy system has the option to pay the full purchase price for the system at the time of purchase or finance the purchase through a 30-year loan from a wholly owned subsidiary of the Company under the MyPower program that the Company launched in the fourth quarter of 2014. The Company can also earn incentives that have been assigned to the Company by its customers, where available from utility companies and state and local governments.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Solar Energy Systems and Components Sales

For solar energy systems and components sales wherein customers pay the full purchase price upon delivery of the system, the Company recognizes revenue, net of any applicable governmental sales taxes, in accordance with ASC 605-25, *Revenue Recognition—Multiple-Element Arrangements*, and ASC 605-10-S99, *Revenue Recognition—Overall—SEC Materials*. Revenue is recognized when (1) persuasive evidence of an arrangement exists, (2) delivery has occurred or services have been rendered, (3) the sales price is fixed or determinable and (4) collection of the related receivable is reasonably assured. Components are comprised of photovoltaic panels and solar energy system mounting hardware. In instances where there are multiple deliverables in a single arrangement, the Company allocates the arrangement consideration to the various elements in the arrangement based on the relative selling price method. The Company recognizes revenue when it installs a solar energy system and the solar energy system passes inspection by the utility or the authority having jurisdiction, provided all other revenue recognition criteria have been met. Costs incurred on residential installations before the solar energy systems are completed are included in inventories as work in progress in the consolidated balance sheets.

The Company recognizes revenue for solar energy systems constructed for certain commercial customers according to ASC 605-35, *Revenue Recognition—Construction-Type and Production Type Contracts*. Revenue is recognized on a percentage-of-completion basis, based on the ratio of labor costs incurred to date to total projected labor costs. Provisions are made for the full amount of any anticipated losses on a contract-by-contract basis. The Company recognized $8.0 million, $2.1 million and $2.9 million of total losses for these types of contracts for the years ended December 31, 2015, 2014 and 2013, respectively. Costs in excess of billings are recorded where costs recognized are in excess of amounts billed to customers of purchased commercial solar energy systems. Costs in excess of billings as of December 31, 2015 and 2014 were $0.2 million and $0.3 million, respectively, and are included in prepaid expenses and other current assets in the consolidated balance sheets. Billings in excess of costs as of December 31, 2015 and 2014 were $0.5 million and $0.2 million, respectively, and are included in deferred revenue in the consolidated balance sheets.

For solar energy systems sold under a MyPower contract, the Company has determined that the arrangement consideration is not currently fixed or determinable. In making this determination, the Company considered that (i) the MyPower arrangement is unique and the Company does not have company-specific or market history for similar financing arrangements with similar asset classes over an extended term; (ii) customer preferences and satisfaction during the life of these long-term contracts, including as a result of technological advances in solar energy systems over time, may change, and the Company may be incented to offer future inducements or concessions to ensure customers remain satisfied during the life of these long-term contracts; and (iii) possible future decreases in the retail prices of electricity from utilities or from other renewable energy sources that may make the purchase of the solar energy systems less economically attractive and may cause the Company to amend the terms of its contracts to ensure continued performance and to remain competitive. Accordingly, the Company initially defers the revenue associated with the sale of a solar energy system under a MyPower contract when it delivers the system that has passed inspection by the utility or the authority having jurisdiction. In instances where there are multiple deliverables in a single MyPower contract, the Company allocates the arrangement consideration to the various elements in the contract based on the relative selling price method. The Company subsequently recognizes revenue for the system over the term of the contract as cash payments are received for the loan's outstanding principal and interest. The deferred revenue is included in the consolidated balance sheets under current portion of deferred revenue for the portion expected to be recognized as revenue in the next 12 months, and the non-current portion is included under deferred revenue, net of current portion. The Company records a note receivable when the customer secures the loan from a subsidiary of the Company to finance the purchase of the solar energy system.

MyPower deferred revenue activity was as follows (in thousands):

	As of and for the Year Ended December 31,	
	2015	2014
Balance - beginning of the period	$ 33,651	$ —
MyPower systems delivered under executed contracts	442,567	33,738
MyPower revenue recognized within solar energy	(23,421)	(87)

systems and components sales		
Balance - end of the period	$ 452,797	$ 33,651

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

As of December 31, 2015 and 2014, $4.6 million and $1.0 million, respectively, are included in the consolidated balance sheets under current portion of deferred revenue. The balances in the table above do not include amounts allocated to remote monitoring services, other deliverables or sales taxes.

Operating Leases and Power Purchase Agreements

The Company is the lessor under lease agreements for solar energy systems, which are accounted for as operating leases in accordance with ASC 840. The Company records operating lease revenue from minimum lease payments, including upfront rebates and incentives earned from such systems, on a straight-line basis over the life of the lease term, assuming all other revenue recognition criteria are met. For incentives that are earned based on amount of electricity generated by the system, the Company records revenue as the amounts are earned. The difference between the payments received and the revenue recognized is recorded as deferred revenue on the consolidated balance sheet.

For solar energy systems where customers purchase electricity from the Company under power purchase agreements, the Company has determined that these agreements should be accounted for, in substance, as operating leases pursuant to ASC 840. Revenue is recognized based upon the amount of electricity delivered at rates specified under the contracts, assuming all other revenue recognition criteria are met.

The portion of rebates and incentives recognized within operating leases and solar energy systems incentives revenue for the years ended December 31, 2015, 2014 and 2013 was $34.3 million, $33.4 million and $26.6 million, respectively.

Remote Monitoring Services

The Company provides solar energy system remote monitoring services, which are generally bundled with both sales and leases of solar energy systems. The Company allocates revenue between remote monitoring services and the other elements in a bundled sale of a solar energy system using the relative selling price method. The selling prices used in the allocation are determined by reference to the prices charged by third parties for similar services and products on a standalone basis. For remote monitoring services bundled with a sale of a solar energy system, the Company recognizes the revenue allocated to remote monitoring services over the term specified in the associated contract or over the warranty period of the solar energy system if the contract does not specify the term. To date, remote monitoring services revenue has not been material and is included in the consolidated statements of operations under both operating leases and solar energy systems incentives revenue, when remote monitoring services are bundled with leases of solar energy systems, and solar energy system sales revenue, when remote monitoring services are bundled with sales of solar energy systems.

Sale-Leaseback

The Company is party to master lease agreements that provide for the sale of solar energy systems to third parties and the simultaneous leaseback of the systems, which the Company then subleases to customers. In sale-leaseback arrangements, the Company first determines whether the solar energy system under the sale-leaseback arrangement is "integral equipment." A solar energy system is determined to be integral equipment when the cost to remove the system from its existing location, including the shipping and reinstallation costs of the solar energy system at the new site, including any diminution in fair value, exceeds ten percent of the fair value of the solar energy system at the time of its original installation. When the leaseback arrangements expire, the Company has the option to purchase the solar energy system, and in most cases, the lessor has the option to sell the system back to the Company, though in some instances the lessor can only sell the system back to the Company prior to expiration of the arrangement.

For solar energy systems that the Company has determined to be integral equipment, the Company has concluded that these rights create a continuing involvement. Therefore, the Company uses the financing method to account for the sale-leaseback of such solar energy systems. Under the financing method, the Company does not recognize as revenue any of the sale proceeds received from the lessor that contractually constitutes a payment to acquire the solar energy system. Instead, the Company treats any such sale proceeds received as financing capital to install and deliver the solar energy system and accordingly records the proceeds as a sale-leaseback financing obligation in the consolidated balance sheets. The Company allocates the leaseback payments made to the lessor between interest expense and a reduction to the sale-leaseback financing obligation. Interest on the financing obligation is calculated using the Company's incremental

borrowing rate at the inception of the arrangement on the outstanding financing obligation. The Company determines its incremental borrowing rate by reference to the interest rates that it would obtain in the financial markets to borrow amounts equal to the sale-leaseback financing obligation over a term similar to the master lease term.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

For solar energy systems that the Company has determined not to be integral equipment, the Company determines if the leaseback is classified as a capital lease or an operating lease. For leasebacks classified as capital leases, the Company initially records a capital lease asset and capital lease obligation in the consolidated balance sheet equal to the lower of the present value of the future minimum leaseback payments or the fair value of the solar energy system. For capital leasebacks, the Company does not recognize any revenue but defers the gross profit comprising of the net of the revenue and the associated cost of sale. For leasebacks classified as operating leases, the Company recognizes a portion of the revenue and the associated cost of sale and defers the portion of revenue and cost of sale that represents the gross profit that is equal to the present value of the future minimum lease payments over the master leaseback term. For both capital and operating leasebacks, the Company records the deferred gross profit in the consolidated balance sheet as deferred income and amortizes the deferred income over the leaseback term as a reduction to the leaseback rental expense included in operating leases and solar energy systems incentives cost of revenue in the consolidated statement of operations.

Cost of Revenue

Operating leases and solar energy systems incentives cost of revenue is primarily comprised of depreciation of the cost of leased solar energy systems reduced by amortization of U.S. Treasury grants income, maintenance costs associated with those systems and amortization of initial direct lease costs associated with those systems. Initial direct lease costs are customer solar energy system lease acquisition costs (the incremental cost of contract administration, referral fees and sales commissions) and are capitalized as an element of solar energy systems and amortized over the term of the related lease or power purchase agreement, which generally ranges from 10 to 20 years. Refer to Note 7, *Solar Energy Systems, Leased and To Be Leased – Net*, for a summary of initial direct lease costs related to customer solar energy system lease acquisition costs.

Solar energy systems and components sales cost of revenue includes direct and indirect material and labor costs, warehouse rent, freight, warranty expense, depreciation on vehicles and other overhead costs. In addition, for solar energy systems and components sales accounted for under the percentage-of-completion method, cost of revenue includes the full amount of any anticipated future losses on a contract-by-contract basis.

Furthermore, the costs associated with solar energy systems sold under MyPower contracts, including the costs of acquisition of system components, personnel costs associated with system installations and costs to originate the contracts such as sales commissions, referral fees and some incremental contract administration costs, are initially capitalized as deferred costs. Subsequently, these costs are recognized as a component of cost of revenue from solar energy systems and components sales for the costs associated with system components and installations, or as a component of operating expenses for costs associated with contract origination, generally in proportion to the reduction of the MyPower loans' outstanding principal over the 30-year term. The deferred costs are included in the consolidated balance sheets under prepaid expenses and other current assets for the portion expected to be recognized in the consolidated statements of operations in the next 12 months, and the non-current portion is included as a component of other assets. However, the estimated warranty costs associated with the systems are fully expensed upon the delivery of the systems.

MyPower deferred costs activity was as follows (in thousands):

	As of and for the Year Ended December 31,	
	2015	2014
Balance - beginning of the period	$ 13,571	$ —
MyPower systems delivered under executed contracts(1)	215,141	13,614
Recognized in cost of revenue within solar energy systems and components sales	(10,490)	(43)
Recognized in operating expenses	(446)	—
Balance - end of the period	$ 217,776	$ 13,571

(1)

Included in MyPower systems delivered under executed contracts was $27.2 million and $0.0 million of MyPower contract origination costs incurred in the years ended December 31, 2015 and 2014, respectively.

As of December 31, 2015 and 2014, $2.1 million and $0.4 million, respectively, are included in the consolidated balance sheets under prepaid and other current assets.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Advertising Costs

Advertising costs are expensed as incurred and are included as an element of sales and marketing expense in the consolidated statements of operations. The Company incurred advertising costs of $28.6 million, $3.4 million and $0.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Income Taxes

The Company accounts for income taxes under an asset and liability approach. Deferred income taxes reflect the impact of temporary differences between assets and liabilities recognized for financial reporting purposes and the amounts recognized for income tax reporting purposes, net operating loss, or NOL, carryforwards and other tax credits measured by applying currently enacted tax laws. A valuation allowance is provided when necessary to reduce deferred tax assets to an amount that is more likely than not to be realized. The Company is eligible for federal investment tax credits. The Company accounts for federal investment tax credits under the flow-through method of accounting. As permitted in ASC 740-10-25-46, under the "flow-through" method of accounting, the tax benefit from an investment tax credit is recorded as a reduction of federal income taxes in the period that the credit is generated.

The Company determines whether a tax position is more likely than not to be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. The Company uses a two-step approach to recognizing and measuring uncertain tax positions. The first step is to evaluate the tax position for recognition by determining if the weight of available evidence indicates that it is more likely than not that the position will be sustained upon tax authority examination, including resolution of related appeals or litigation processes, if any. The second step is to measure the tax benefit as the largest amount that is more than 50% likely of being realized upon ultimate settlement.

The Company's policy is to include interest and penalties related to unrecognized tax benefits, if any, within the provision for taxes in the consolidated statements of operations.

The Company uses the "with and without" approach in determining the order in which tax attributes are utilized. As a result, the Company only recognizes a tax benefit from stock-based awards in additional paid-in capital if an incremental tax benefit is realized after all other tax attributes currently available to the Company have been utilized.

Comprehensive Income (Loss)

The Company accounts for comprehensive income (loss) in accordance with ASC 220, *Comprehensive Income*. Under ASC 220, the Company is required to report comprehensive income (loss), which includes net income (loss) as well as other comprehensive income (loss). There were no significant other comprehensive income (losses) and no significant differences between comprehensive loss as defined by ASC 220 and net loss as reported in the consolidated statements of operations, for the periods presented.

Stock-Based Compensation

The Company accounts for stock-based compensation costs under the provisions of ASC 718, *Compensation—Stock Compensation*, which requires the measurement and recognition of compensation expense related to the fair value of stock-based compensation awards that are ultimately expected to vest. Stock-based compensation expense recognized includes the compensation cost for all share-based payments granted to employees based on the grant date fair value estimated in accordance with the provisions of ASC 718. ASC 718 is also applied to awards modified, repurchased, or canceled during the periods reported.

The Company applies ASC 718 and ASC Subtopic 505-50, *Equity-Based Payments to Non Employees*, to options and other stock-based awards issued to nonemployees. In accordance with ASC 718 and ASC Subtopic 505-50, the Company uses the Black-Scholes option-pricing model to measure the fair value of the options at the measurement date. The measurement of stock-based compensation is subject to periodic adjustments as the awards vest and the resulting

change in fair value is recognized in the consolidated statements of operations in the period the related services are rendered.

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Notes to Consolidated Financial Statements (continued)

Noncontrolling Interests and Redeemable Noncontrolling Interests

Noncontrolling interests and redeemable noncontrolling interests represent third-party interests in the net assets under certain funding arrangements, or funds, that the Company has entered into to finance the cost of solar energy systems under operating leases. The Company has determined that the contractual provisions in the funds represent substantive profit sharing arrangements. The Company has further determined that the appropriate methodology for calculating the noncontrolling interest and redeemable noncontrolling interests balances that reflect the substantive profit sharing arrangements is a balance sheet approach using the hypothetical liquidation at book value, or HLBV, method. The Company therefore determines the amount of the noncontrolling interests and redeemable noncontrolling interests in the net assets at each balance sheet date using the HLBV method, which is presented on the consolidated balance sheets as noncontrolling interests in subsidiaries and redeemable noncontrolling interests in subsidiaries. Under the HLBV method, the amounts reported as noncontrolling interests and redeemable noncontrolling interests in the consolidated balance sheets represent the amounts the third parties would hypothetically receive at each balance sheet date under the liquidation provisions of the funds, assuming the net assets of the funds were liquidated at the recorded amounts determined in accordance with GAAP and distributed to the third parties. The third parties' interests in the results of operations of the funds is determined as the difference in the noncontrolling interests and redeemable noncontrolling interests balance in the consolidated balance sheets between the start and end of each reporting period, after taking into account any capital transactions between the funds and the third parties. However, the redeemable noncontrolling interests balance is at least equal to the redemption amount. The noncontrolling interests and redeemable noncontrolling interests balance is presented as a component of permanent equity in the consolidated balance sheets or as temporary equity in the mezzanine section of the consolidated balance sheets as redeemable noncontrolling interests when the third-parties have the right to redeem their interests in the funds for cash or other assets.

Segment Information

Operating segments are defined as components of a company about which separate financial information is available that is evaluated regularly by the chief operating decision maker, or decision making group, in deciding how to allocate resources and in assessing performance. The Company's chief operating decision maker is the executive team, which is comprised of the chief executive officer, the president, the chief technology officer, the chief revenue officer, and the chief financial officer. Based on the financial information presented to and reviewed by the chief operating decision maker in deciding how to allocate the resources and in assessing the performance of the Company, the Company has determined that it has a single operating and reporting segment: solar energy products and services. The Company's principal operations, revenue and decision-making functions are located in the United States.

Basic and Diluted Net Income (Loss) Per Share

The Company's basic net income (loss) per share attributable to common stockholders is calculated by dividing the net income (loss) attributable to common stockholders by the weighted-average number of shares of common stock outstanding for the period.

The diluted net income (loss) per share attributable to common stockholders is computed by giving effect to all potential common stock equivalents outstanding for the period determined using the treasury stock method or the if-converted method, as applicable. In periods when the Company incurred a net loss attributable to common stockholders, stock options, restricted stock units and convertible senior notes were considered to be common stock equivalents but have been excluded from the calculation of diluted net loss per share attributable to common stockholders as their effect is antidilutive.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, to replace the existing revenue recognition criteria for contracts with customers and to establish the disclosure requirements for revenue from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, *Revenue from Contracts with Customers – Deferral of the Effective Date*, to defer the effective date of ASU No. 2014-09 to interim and annual periods beginning after December 15, 2017, with early adoption permitted. Adoption of the ASUs is either retrospective to each prior period

presented or retrospective with a cumulative adjustment to retained earnings or accumulated deficit as of the adoption date. The Company is currently assessing the impact of the ASUs on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, *Going Concern*, to provide guidance within GAAP requiring management to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and requiring related disclosures. The ASU is effective for annual periods ending after December 15, 2016. The Company believes that the ASU will have no impact on its consolidated financial statements.

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Notes to Consolidated Financial Statements (continued)

In February 2015, the FASB issued ASU No. 2015-02, *Amendments to the Consolidation Analysis*, to amend the criteria for consolidation of certain legal entities. The ASU is effective for interim and annual periods beginning after December 15, 2015. Adoption of the ASU is either retrospective to each prior period presented or retrospective with a cumulative adjustment to retained earnings or accumulated deficit as of the adoption date. The Company is currently assessing the impact of the ASU on its consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, to require debt issuance costs to be presented as an offset against debt outstanding as opposed to an asset. The ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. Adoption of the ASU is retrospective to each prior period presented. As of December 31, 2015, the Company early adopted the ASU. As a result, for each prior period presented, the Company reclassified the debt issuance costs previously within prepaid expenses and other current assets and other assets (non-current) to current portion of long-term debt; current portion of solar asset-backed notes; long-term debt, net of current portion; convertible senior notes and solar asset-backed notes, net of current portion, as appropriate (see above).

In July 2015, the FASB issued ASU No. 2015-11, *Simplifying the Measurement of Inventory*, to specify that inventory should be subsequently measured at the lower of cost or net realizable value, which is the ordinary selling price less any completion, transportation and disposal costs. However, the ASU does not apply to inventory measured using the last-in-first-out or retail methods. The ASU is effective for interim and annual periods beginning after December 15, 2016. Adoption of the ASU is prospective. The Company does not anticipate that the adoption of the ASU will have a material impact on its consolidated financial statements.

In September 2015, the FASB issued ASU No. 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*, to change the accounting for subsequent adjustments to the provisional balances recognized in a business combination from retrospective to prospective. However, the ASU requires separate presentation or disclosure of the impact on prior periods had the adjustments been recognized as of the acquisition date. The ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. Adoption of the ASU is prospective. The Company does not anticipate that the adoption of the ASU will have a material impact on its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, to eliminate the requirement to classify deferred income tax assets and liabilities between current and noncurrent. The ASU simply requires that all deferred income tax assets and liabilities be classified as noncurrent. The ASU is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. Adoption of the ASU is either retrospective to each prior period presented or prospective. As of December 31, 2015, the Company early adopted the ASU prospectively. As a result, the Company no longer presents any current deferred income tax assets or liabilities but did not reclassify prior period deferred income tax assets or liabilities, as permitted by the ASU.

In January 2016, the FASB issued ASU No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, to mainly change the accounting for investments in equity securities and financial liabilities carried at fair value as well as to modify the presentation and disclosure requirements for financial instruments. The ASU is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted. Adoption of the ASU is retrospective with a cumulative adjustment to retained earnings or accumulated deficit as of the adoption date. The Company is currently assessing the impact of the ASU on its consolidated financial statements.

3. Acquisitions

Silevo

On September 23, 2014, the Company completed its acquisition of Silevo, a designer and manufacturer of high performance solar cells that are manufactured into photovoltaic panels. Silevo's primary operations are in the United States, where it carries-out research and development activities as well as sales of products, and in China, where it is the managing partner in a joint venture that manufactures the solar cells for the subsequent contract manufacturing of high performing photovoltaic panels. The acquisition was expected to enable the Company to manage its supply chain and control the design and manufacturing of solar cells and photovoltaic panels that are a key component of the Company's

solar energy systems, as well as enable the Company to utilize and combine Silevo's technology with economies of scale to achieve significant cost reductions.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

The purchase consideration was comprised of $0.3 million in cash and 2,284,070 shares of the Company's common stock with an aggregate fair value of $138.0 million based on the closing price of the Company's common stock on the acquisition date. Additionally, the Company may pay up to approximately $150.0 million in additional shares of the Company's common stock to Silevo's former stockholders, subject to the achievement of specified production milestones, as contingent consideration. No amounts would be payable for any milestones not achieved. As of the acquisition date, the Company estimated the fair value of the contingent consideration was $115.3 million using a probability-weighted discounted cash flow methodology. The Company also issued to Silevo employees rights to receive shares of the Company's common stock as replacements for unvested Silevo common stock options, which vest as the employees provide future services to the Company. The purchase consideration included $16.8 million that comprised amounts that had previously been advanced to Silevo and also costs paid by the Company on behalf of the sellers. The following table summarizes the fair value of the purchase consideration as of the acquisition date (in thousands):

Cash	$	326
Common stock		137,958
Restricted stock units issued to replace Silevo's unvested stock options		132
Amounts advanced to Silevo prior to acquisition and costs paid on behalf of sellers at acquisition		16,760
Closing consideration payable		413
Contingent consideration payable		115,319
Total purchase consideration	**$**	**270,908**

The following table summarizes the fair values of the assets acquired, the liabilities assumed and the noncontrolling interests as of the acquisition date (in thousands):

Cash	$	2,899
Accounts receivable		642
Inventories		8,182
Prepaid and other assets		899
Property, plant and equipment		28,281
Accounts payable and other liabilities		(5,427)
Term loan		(9,103)
Deferred tax liabilities		(27,332)
Intangible assets		119,000
Total identifiable net assets at fair value		**118,041**
Redeemable noncontrolling interests		(14,174)
Goodwill		167,041
Total purchase consideration	**$**	**270,908**

The goodwill recognized was primarily attributable to the value of expected synergies, efficiencies and cost savings that the Company expects to achieve in leveraging Silevo's technology in the volume manufacturing of high efficiency photovoltaic panels, in addition to the value of the assembled workforce and the manufacturing experience of Silevo. The acquisition of Silevo's technology is anticipated to reduce the Company's costs of procuring photovoltaic panels, reduce the number of photovoltaic panels and other components used in solar energy systems, reduce the installation time of solar energy systems and improve efficiencies and profitability. The full amount of the goodwill is not deductible for tax purposes.

The following table summarizes the acquired intangible assets as of the acquisition date:

	Weighted-Average

	Fair Value (in thousands)	Useful Life (in years)
Developed technology	$ 115,000	10
Build-to-suit lease arrangement	4,000	10
Total	$ 119,000	

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Ilioss

On August 7, 2015, the Company acquired all of the outstanding shares of ILIOSSON, S.A. de C.V., or Ilioss, a designer and marketer of commercial and industrial solar energy systems in Mexico. Historically, Ilioss subcontracted the installation of its solar energy systems and sold them to financing companies along with the related customer power purchase agreements. The Company has vertically integrated Ilioss' operations, and expects to continue to expand throughout Mexico.

The purchase consideration was comprised of $9.7 million payable in cash. Additionally, the Company would pay earn-outs comprising of (i) $5.0 million in cash upon the successful achievement of a commercial battery storage deployment milestone on or before June 30, 2016 and (ii) additional cash consideration based on the number of megawatts deployed by Ilioss in Mexico from the acquisition date through December 31, 2019. The terms of the earn-out payments require the sellers to remain employed to receive the earn-out payments. No amounts would be payable for any earn-outs not achieved. The Company has determined that any earn-out payments would be compensation for post-acquisition services, and the Company will, therefore, recognize them as they are earned. The Company estimates that the aggregate earn-out payments will be approximately $15.6 million, the majority of which is expected to be deferred on the consolidated balance sheet as costs of originating customer contracts and subsequently recognized as expenses over the term of the associated customer lease or power purchase agreements.

The following table summarizes the preliminary assessment of the fair values of the assets acquired and the liabilities assumed as of the acquisition date (in thousands). The Company is in the process of completing the valuation of the assets acquired and the liabilities assumed. Accordingly, the preliminary fair values reflected in the following table are subject to change.

Cash	$ 145
Accounts receivable	241
Prepaid and other assets	307
Property, plant and equipment	18
Accounts payable and other liabilities	(1,015)
Deferred revenue	(553)
Deferred tax liabilities	(1,855)
Intangible assets	6,420
Total identifiable net assets at fair value	**3,708**
Goodwill	5,945
Total purchase consideration	**$ 9,653**

The goodwill recognized was primarily attributable to Ilioss' assembled workforce and their knowledge and experience with the Mexican solar energy market that would enable the Company to grow its presence in Mexico. The full amount of the goodwill is not deductible for tax purposes.

The following table summarizes the acquired intangible assets as of the acquisition date:

	Fair Value (in thousands)	Weighted-Average Useful Life (in years)
Customer relationships	$ 6,190	6
Non-compete agreements	230	3
Total	$ 6,420	

Pro forma financial information and the historical revenue and earnings of Ilioss are not presented as they were not material to the consolidated statements of operations.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

4. Goodwill and Intangible Assets

The Company is in the process of completing the valuation of certain assets and liabilities from the Ilioss acquisition discussed in Note 3, *Acquisitions*, including the gross amounts of certain intangible assets presented in the table below amounting to $6.4 million. Such amounts are preliminary and subject to change. There were no material changes recorded in the year ended December 31, 2015 related to the amounts reported in the Company's Form 10-K for the year ended December 31, 2014, except for the periodic amortization of the intangible assets.

Intangible Assets

The following is a summary of intangible assets as of December 31, 2015 (in thousands):

	Weighted-average useful life (in years)	Gross	Accumulated amortization	Net
Developed technology - Silevo	10	$ 115,000	$ (14,596)	$ 100,404
Developed technology - Zep Solar	7	60,100	(17,664)	42,436
Trademarks and trade names	7	24,700	(7,256)	17,444
Marketing database	5	17,427	(9,953)	7,474
PowerSaver agreement	10	17,077	(3,961)	13,116
Non-compete agreements	5	7,189	(3,272)	3,917
Customer relationships	6	6,190	(542)	5,648
Other	6	10,028	(5,223)	4,805
Total	8.26	$ 257,711	$ (62,467)	$ 195,244

The following is a summary of intangible assets as of December 31, 2014 (in thousands):

	Weighted-average useful life (in years)	Gross	Accumulated amortization	Transfers to solar energy systems, leased and to be leased	Write-offs and cancellations	Net
Developed technology - Silevo	10	$115,000	$ (3,096)	$ —	$ —	111,904
Developed technology - Zep Solar	7	60,100	(9,070)	—	—	51,030
Trademarks and trade names	7	24,700	(3,728)	—	—	20,972
Marketing database	5	17,427	(4,599)	—	—	12,828
PowerSaver agreement	10	17,077	(2,253)	—	—	14,824
Solar energy systems backlog	30	12,434	—	(10,755)	(1,679)	—
Non-compete agreements	5	6,959	(1,836)	—	—	5,123
Other	6	10,028	(3,072)	—	—	6,956
Total	9.35	$263,725	$ (27,654)	$ (10,755)	$ (1,679)	$223,637

Developed Technology – Silevo

Silevo developed technology represents high performance solar cell technology acquired through the Silevo acquisition. The high performance technology would allow the Company to achieve improved solar energy system performance and reduce the overall deployment cost per watt of the solar energy systems sold or leased. In addition, the high performance technology would increase the Company's market opportunity to a broader customer base who would benefit economically from more efficient solar energy systems.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Developed Technology – Zep Solar

Zep Solar developed technology represents solar panel interlocking technology that includes a rail-free installation system, auto-grounding connections and a rapid, drop-in module installation design. These features allow solar energy systems to be installed easily and produce significant performance-based and aesthetic improvements compared to other solar energy system installation technologies.

Trademarks and Trade Names

Trademarks and trade names are related to established market recognition from acquired businesses and are expected to be retired at the end of their estimated useful lives.

Marketing Database

The marketing database is a comprehensive platform for targeted marketing, including a prospective customer scoring engine, a marketing campaign manager and monthly updates. The prospective customer scoring engine improves the results of marketing initiatives by predicting which customer leads in the marketing database will respond favorably to a particular marketing campaign. The marketing campaign manager monitors the results of marketing campaigns and provides feedback for optimizing future marketing campaigns.

PowerSaver Agreement

Under the PowerSaver program, Fannie Mae makes available additional loans of up to $25,000 to eligible Fannie Mae borrowers. The additional loan amounts can only be used for energy efficiency projects that include the installation of solar energy systems. The PowerSaver program provides an additional source of financing for customers and therefore helps broaden the Company's customer base. Under the PowerSaver agreement, the Company is provided with the exclusive right to market solar energy systems to the customers of Paramount Mortgage, an affiliate of Paramount Energy.

Solar Energy Systems Backlog

Solar energy systems backlog represents the value attributable to the contractual arrangements entered into between Paramount Energy and its customers to install solar energy systems for which the installation had not commenced as of the acquisition date. The arrangements were acquired by the Company. This balance was transferred to solar energy systems, leased and to be leased, as the solar energy systems are installed and placed in service and subsequently depreciated as cost of solar energy systems over the estimated useful lives of the solar energy systems of 30 years.

Non-Compete Agreements

Certain former key employees of businesses acquired by the Company became employees of the Company and executed non-compete agreements with the Company.

Customer Relationships

Ilioss had a pre-existing relationship with a leading chain of Mexican retail stores.

Other

Other intangible assets include a mortgage database, which contains data pertaining to households that the Company can directly market to. In addition, there is a build-to-suit lease arrangement with an affiliate of the State of New York whereby the affiliate will construct a facility to manufacture photovoltaic panels, procure manufacturing equipment for use in the facility and subsequently lease the facility and the manufacturing equipment to the Company. The build-to-suit lease arrangement is further discussed in Note 22, *Commitments and Contingencies*. Furthermore, there is internally developed software, which consists of Zep Solar's Zepulator System Designer, or Zepulator, online application. Zepulator

can project the size, scope, layout, materials and costs of potential solar energy system installations, which assists with optimizing solar energy system installations.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

All intangible assets, with the exception of the solar energy systems backlog, are amortized over their estimated useful lives. The changes to the carrying value of intangible assets were as follows (in thousands):

	Year Ended December 31,	
	2015	2014
Balance - beginning of the period	$ 223,637	$ 129,290
Acquisitions	6,420	119,000
Amortization	(34,813)	(24,263)
Transfers to solar energy systems, leased and to be leased	—	(140)
Write-offs and cancellations	—	(250)
Balance - end of the period	$ 195,244	$ 223,637

Amortization expense for intangible assets for the years ended December 31, 2015, 2014 and 2013 was allocated as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Included in operating leases and solar energy incentives cost of revenue	$ 17,428	$ 9,962	$ 582
Included in solar energy systems and components sales cost of revenue	3,337	2,605	—
Total included in cost of revenue	20,765	12,567	582
Included in sales and marketing	14,048	11,696	2,809
Total amortization expense	$ 34,813	$ 24,263	$ 3,391

No intangible assets were impaired during the years ended December 31, 2015, 2014 and 2013. However, the Company wrote-off $0.3 million and $1.4 million of solar energy systems backlog related to contracts cancelled after acquisition, during the years ended December 31, 2014 and 2013, respectively, which was recorded in sales and marketing expense in the consolidated statements of operations.

As of December 31, 2015, total future amortization expense for intangible assets was as follows (in thousands):

	Cost of Revenue	Operating Expense	Total
2016	$ 20,697	$ 11,689	$ 32,386
2017	20,541	10,609	31,150
2018	20,541	9,237	29,778
2019	20,541	6,329	26,870
2020	19,821	6,129	25,950
Thereafter	44,532	4,578	49,110
Total	$ 146,673	$ 48,571	$ 195,244

Goodwill

The changes to the carrying value of goodwill were as follows (in thousands):

	Year Ended December 31,	
	2015	2014
Balance - beginning of the period	$ 315,920	$ 148,879

Acquisitions	5,945	167,041
Balance - end of the period	$ 321,865	$ 315,920

The Company did not recognize any impairment of goodwill during the years ended December 31, 2015, 2014 or 2013.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

5. Noncancelable Operating Lease Payments Receivable

As of December 31, 2015, future minimum lease payments to be received from customers under noncancelable operating leases for each of the next five years and thereafter were as follows (in thousands):

2016	89,801
2017	90,352
2018	91,888
2019	93,457
2020	95,079
Thereafter	1,347,298
Total	$ 1,807,875

The Company enters into power purchase agreements with its customers that are accounted for, in substance, as leases. These customers are charged solely based on actual power produced by the installed solar energy system at a predefined rate per kilowatt-hour of power produced. The future payments from such arrangements were not included in the table above as they are a function of the power generated by the related solar energy systems in the future.

Included in revenue for the years ended December 31, 2015, 2014 and 2013 was $124.7 million, $79.5 million and $42.0 million, respectively, that were accounted for as contingent rentals. The contingent rentals comprised of customer payments under power purchase agreements and performance-based incentives received or receivable by the Company from various utility companies.

6. Inventories

Inventories consisted of the following (in thousands):

	As of December 31,	
	2015	2014
Raw materials	$ 335,439	$ 209,251
Work in progress	7,512	7,972
Total	$ 342,951	$ 217,223

Raw materials are comprised of component parts that include silicon wafers, process gasses, chemicals and other consumables used in solar cell production, solar cells, photovoltaic panels, inverters, mounting hardware and miscellaneous electrical components that will be deployed to either solar energy systems that will be sold or solar energy systems that will be leased. Work in progress is comprised of installations in progress and includes component parts, labor and other overhead costs incurred up to the balance sheet date on solar energy systems that will be sold and for which binding sales contracts have already been executed. For solar energy systems, leased and to be leased, the Company commences transferring component parts from inventory to construction in progress, a component of solar energy systems, leased and to be leased, once a lease contract with a customer has been executed and installation has been initiated. Additional costs incurred on the leased systems, including labor and overhead, are recorded within construction in progress. As of December 31, 2015 and 2014, inventory reserves were $4.5 million and $3.1 million, respectively, and are included in the table above under raw materials.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

7. Solar Energy Systems, Leased and To Be Leased – Net

Solar energy systems, leased and to be leased – net consisted of the following (in thousands):

	As of December 31,	
	2015	2014
Solar energy systems leased to customers	$ 3,619,214	$ 2,388,548
Initial direct costs related to customer solar energy system lease acquisition costs	383,506	207,537
	4,002,720	2,596,085
Less accumulated depreciation and amortization	(275,158)	(159,160)
	3,727,562	2,436,925
Solar energy systems under construction	358,010	131,048
Solar energy systems to be leased to customers	289,981	228,823
Solar energy systems, leased and to be leased - net(1)(2)	$ 4,375,553	$ 2,796,796

(1) Included in solar energy systems leased to customers as of December 31, 2015 and 2014 was $66.4 million related to capital leased assets, with an accumulated depreciation of $10.6 million and $7.9 million, respectively.
(2) Included in solar energy systems leased to customers as of December 31, 2015 and 2014 was $6.3 million and $3.5 million, respectively, related to energy storage systems with an accumulated depreciation of $0.5 million and $0.1 million, respectively.

As of December 31, 2015, future minimum lease payments to the lessor under this lease arrangement for each of the next five years and thereafter were as follows (in thousands):

2016	2,339
2017	2,353
2018	2,367
2019	2,383
2020	2,398
Thereafter	18,674
Total	$ 30,514

As of December 31, 2015, future minimum lease receipts to be paid to the Company by sub-lessees under this lease arrangement for each of the next five years and thereafter were as follows (in thousands):

2016	2,444
2017	2,473
2018	2,503
2019	2,534
2020	2,566
Thereafter	31,591
Total	$ 44,111

The amounts in the table above are also included as part of the noncancelable operating lease payments from customers disclosed in Note 5, *Noncancelable Operating Lease Payments Receivable.*

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

8. Property, Plant and Equipment – Net

Property, plant and equipment consisted of the following (in thousands):

	As of December 31,	
	2015	2014
Manufacturing facilities - Fremont, California:		
Manufacturing and lab equipment	$ 84,418	$ 2,325
Leasehold improvements	53,902	—
Manufacturing facilities - China:		
Manufacturing and lab equipment	21,714	19,352
Land and buildings	6,711	6,711
Vehicles	44,036	28,815
Computer hardware and software	41,294	28,724
Furniture and fixtures	13,611	5,501
Leasehold improvements - other	19,546	13,992
Other	30,861	569
	316,093	105,989
Less accumulated depreciation and amortization	(53,706)	(30,525)
Property, plant and equipment - net	$ 262,387	$ 75,464

9. Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following (in thousands):

	As of December 31,	
	2015	2014
Accrued expenses	$ 110,050	$ 27,485
Accrued compensation	64,988	50,414
Current portion of contingent consideration	42,912	41,978
Accrued warranty	22,993	8,607
Accrued professional services fees	9,915	6,813
Accrued sales and use taxes	7,875	10,438
Current portion of capital lease obligation	8,208	3,430
Current portion of deferred gain on sale-leaseback transactions	3,243	3,243
Total	$ 270,184	$ 152,408

The current portion of contingent consideration is related to the Company's acquisition of Silevo in the third quarter of 2014 (see Note 3, *Acquisitions*).

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

10. Other Liabilities and Deferred Credits

Other liabilities and deferred credits consisted of the following (in thousands):

	As of December 31,	
	2015	2014
Deferred gain on sale-leaseback transactions, net of current portion	$ 51,547	$ 54,790
Deferred rent expense	16,184	4,838
Capital lease obligation	39,475	27,791
Liability for receipts from an investor(1)	17,975	3,213
Contingent consideration	80,096	75,219
Participation interest(2)	15,919	15,556
Other noncurrent liabilities	57,810	36,617
Total	$ 279,006	$ 218,024

(1) The liability for receipts from an investor represents amounts received from an investor under a lease pass-through fund arrangement for monetization of ITCs for assets not yet placed in service. This amount is reclassified to deferred revenue when the assets are placed in service.

(2) The participation interest represents rights granted by the Company to a former investor to share in the future residual returns from securitized solar energy systems as part of the compensation for the termination of a lease pass-through fund arrangement, as described in Note 11, *Indebtedness*.

The contingent consideration relates to the Company's acquisition of Silevo in the third quarter of 2014 (see Note 3, *Acquisitions*).

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

11. Indebtedness

The following is a summary of the Company's debt as of December 31, 2015 (dollars in thousands):

	Unpaid Principal Balance	Net Carrying Value		Unused Borrowing Capacity	Interest Rate	Maturity Dates
		Current	Long-Term			
Recourse debt:						
Secured revolving credit facility	$ 360,000	$ 22,320	$ 333,287	$ 13,053	3.5%-5.8%	December 2016 - December 2017
Vehicle and other loans	28,173	12,562	15,610	—	2.5%-7.6%	January 2016 - June 2019
2.75% convertible senior notes due in 2018	230,000	—	225,795	—	2.8%	November 2018
1.625% convertible senior notes due in 2019	566,000	—	555,981	—	1.6%	November 2019
Zero-coupon convertible senior notes due in 2020	113,000	—	112,784	—	0.0%	December 2020
Solar Bonds	214,324	178,309	35,778	*	1.3%-5.8%	January 2016 - December 2030
Total recourse debt	1,511,497	213,191	1,279,235	13,053		
Non-recourse debt:						
Term loan due in May 2016	34,622	33,918	—	—	3.5%	May 2016
Term loan due in December 2016	112,483	111,248	—	—	3.6%-3.7%	December 2016
MyPower revolving credit facility	213,125	—	210,735	26,875	3.0%-5.5%	January 2017
Revolving aggregation credit facility	455,693	—	446,963	194,307	3.1%-3.2%	December 2017
Solar Asset-backed Notes, Series 2013-1	45,845	3,342	39,669	—	4.8%	November 2038
Solar Asset-backed Notes, Series 2014-1	64,431	2,855	58,938	—	4.6%	April 2044
Solar Asset-backed Notes, Series 2014-2	193,755	6,319	181,041	—	4.0%-Class A 5.4%-Class B	July 2044
Solar Asset-backed Notes, Series 2015-1	122,295	1,348	116,019	—	4.2%-Class A 5.6%-Class B	August 2045
Total non-recourse debt	1,242,249	159,030	1,053,365	221,182		
Total debt	$2,753,746	$372,221	$2,332,600	$234,235		

* Out of the $350.0 million authorized to be issued by the Company's board of directors, $135.7 million remained available to be issued. See below and Note 21, *Related Party Transactions*, for Solar Bonds issued to related parties.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

The following is a summary of the Company's debt as of December 31, 2014 (dollars in thousands):

	Unpaid Principal Balance	Net Carrying Value		Unused Borrowing Capacity	Interest Rate	Maturity Date
		Current	Long-Term			
Recourse debt:						
Secured revolving credit facility	$ 130,000	$ —	$ 126,659	$ 54,935	3.4%	December 2016
Vehicle loans	9,724	2,647	7,077	—	1.9%-7.5%	March 2015 - June 2019
2.75% convertible senior notes due in 2018	230,000	—	224,311	—	2.8%	November 2018
1.625% convertible senior notes due in 2019	566,000	—	553,415	—	1.6%	November 2019
Solar Bonds	3,943	989	2,663	#	2.0%-4.0%	October 2015 - October 2018
Total recourse debt	939,667	3,636	914,125	54,935		
Non-recourse debt:						
Term loan assumed from Silevo acquisition	9,134	9,134	—	—	7.8%	June 2015
Term loan due in May 2016	34,195	—	31,174	90,805	3.2%	May 2016
Term loan due in December 2016	122,655	—	117,879	127,345	3.4%-3.5%	December 2016
Solar Asset-backed Notes, Series 2013-1	49,519	3,167	43,395	—	4.8%	November 2038
Solar Asset-backed Notes, Series 2014-1	67,676	2,686	62,250	—	4.6%	April 2044
Solar Asset-backed Notes, Series 2014-2	201,494	7,304	187,570	—	4.0%-Class A 5.4%-Class B	July 2044
Total non-recourse debt	484,673	22,291	442,268	218,150		
Total debt	$1,424,340	$ 25,927	$1,356,393	$273,085		

Out of the $200.0 million authorized to be issued by the Company's board of directors, $196.1 million remained available to be issued. See below and Note 21, *Related Party Transactions*, for Solar Bonds issued to related parties.

Recourse debt refers to debt that is recourse to the Company's general assets. Non-recourse debt refers to debt that is recourse to only specified assets or subsidiaries of the Company. The differences between the unpaid principal balances and the net carrying values are due to debt discounts and deferred financing costs. The Company's debt is described further below.

Recourse Debt Facilities:

Secured Revolving Credit Facility

In September 2012, the Company entered into a revolving credit agreement with a syndicate of banks to obtain funding for working capital, letters of credit and funding for general corporate needs. On June 29, 2015, the committed amount under the secured revolving credit facility was increased to $260.0 million. On July 24, 2015, the committed amount under the secured revolving credit facility was increased to $333.5 million. In December 2015, the committed amount under the secured revolving credit facility was increased to $398.5 million, and the maturity date was extended to December 31, 2017 for substantially all amounts borrowed, and to be borrowed, under the secured revolving credit facility. Borrowed funds bear interest, at the Company's option, at an annual rate of (a) 3.25% plus LIBOR or (b) 2.25% plus the highest of (i) the federal funds rate plus 0.50%, (ii) Bank of America's published "prime rate" or (iii) LIBOR plus 1.00%. The fee for undrawn commitments is 0.375% per annum. The secured revolving credit facility is secured by certain of the Company's machinery and equipment, accounts receivable, inventory and other assets. The Company was in compliance with all financial covenants as of December 31, 2015.

Vehicle and Other Loans

The Company has entered into various vehicle and other loan agreements with various financial institutions. The vehicle loans are secured by the vehicles financed. The Company was in compliance with all financial covenants as of December 31, 2015.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

2.75% Convertible Senior Notes Due in 2018

In October 2013, the Company issued $230.0 million in aggregate principal of 2.75% convertible senior notes due on November 1, 2018 through a public offering. The net proceeds from the offering, after deducting transaction costs, were $222.5 million. The debt issuance costs were recorded as a debt discount and are being amortized to interest expense over the contractual term of the convertible senior notes.

Each $1,000 of principal of the convertible senior notes is initially convertible into 16.2165 shares of the Company's common stock, which is equivalent to an initial conversion price of $61.67 per share, subject to adjustment upon the occurrence of specified events related to dividends, tender offers or exchange offers. Holders of the convertible senior notes may convert their convertible senior notes at their option at any time up to and including the second scheduled trading day prior to maturity. If certain events that would constitute a make-whole fundamental change, such as significant changes in ownership, corporate structure or tradability of the Company's common stock, occur prior to the maturity date, the Company would increase the conversion rate for a holder who elects to convert its convertible senior notes in connection with such an event in certain circumstances. The maximum conversion rate is capped at 21.4868 shares for each $1,000 of principal of the convertible senior notes, which is equivalent to a minimum conversion price of $46.54 per share. The convertible senior notes do not have a cash conversion option. The convertible senior note holders may require the Company to repurchase their convertible senior notes for cash only under certain defined fundamental changes. The Company was in compliance with all debt covenants as of December 31, 2015.

1.625% Convertible Senior Notes Due in 2019

In September 2014, the Company issued $500.0 million in aggregate principal of 1.625% convertible senior notes due on November 1, 2019 through a private placement. The net amount from the issuance, after deducting transaction costs, was $488.3 million. On October 10, 2014, the Company issued an additional $66.0 million in aggregate principal of the 1.625% convertible senior notes, pursuant to the exercise of an option by the initial purchasers. The net amount from the additional issuance, after deducting transaction costs, was $64.5 million. The debt issuance costs were recorded as a debt discount and are being amortized to interest expense over the contractual term of the convertible senior notes.

Each $1,000 of principal of the convertible senior notes is initially convertible into 11.972 shares of the Company's common stock, which is equivalent to an initial conversion price of $83.53 per share, subject to adjustment upon the occurrence of specified events related to dividends, tender offers or exchange offers. Holders of the convertible senior notes may convert their convertible senior notes at their option at any time up to and including the second scheduled trading day prior to maturity. If certain events that would constitute a make-whole fundamental change, such as significant changes in ownership, corporate structure or tradability of the Company's common stock, occur prior to the maturity date, the Company would increase the conversion rate for a holder who elects to convert its convertible senior notes in connection with such an event in certain circumstances. The maximum conversion rate is capped at 15.8629 shares for each $1,000 of principal of the convertible senior notes, which is equivalent to a minimum conversion price of $63.04 per share. The convertible senior notes do not have a cash conversion option. The convertible senior note holders may require the Company to repurchase their convertible senior notes for cash only under certain defined fundamental changes. The Company was in compliance with all debt covenants as of December 31, 2015.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

In connection with the issuance of the convertible senior notes in September 2014, the Company paid $57.6 million to enter into capped call option agreements to reduce the potential dilution to holders of the Company's common stock upon conversion of the convertible senior notes. In connection with the additional issuance of the convertible senior notes on October 10, 2014, the Company paid $7.6 million to enter into an additional capped call option agreement. Specifically, upon the exercise of the capped call options, the Company would receive shares of its common stock equal to 6,776,152 shares multiplied by (a) (i) the lower of $126.08 or the then market price of its common stock less (ii) $83.53 and divided by (b) the then market price of its common stock. The results of this formula are that the Company would receive more shares as the market price of its common stock exceeds $83.53 and approaches $126.08, but the Company would receive fewer shares as the market price of its common stock exceeds $126.08. Consequently, if the convertible senior notes are converted, then the number of shares to be issued by the Company would be effectively partially offset by the shares received by the Company under the capped call options as they are exercised. The Company can also elect to receive the equivalent value of cash in lieu of shares. The capped call options expire on various dates ranging from September 4, 2019 to October 29, 2019, and the formula above would be adjusted in the event of a merger; a tender offer; nationalization; insolvency; delisting of the Company's common stock; changes in law; failure to deliver; insolvency filing; stock splits, combinations, dividends, repurchases or similar events; or an announcement of certain of the preceding actions. Although intended to reduce the net number of shares issued after a conversion of the convertible senior notes, the capped call options were separately negotiated transactions, are not a part of the terms of the convertible senior notes, do not affect the rights of the convertible senior note holders and will take effect regardless of whether the convertible senior notes are actually converted. The capped call options met the criteria for equity classification because they are indexed to the Company's common stock and the Company always controls whether settlement will be in shares or cash. As a result, the amounts paid for the capped call options were recorded as reductions to additional paid-in capital. The capped call option agreements are excluded from the calculation of diluted net income (loss) per share attributable to common stockholders as their effect is antidilutive.

Zero-Coupon Convertible Senior Notes Due in 2020

In December 2015, the Company issued $113.0 million in aggregate principal of zero-coupon convertible senior notes due on December 1, 2020 through a private placement. $13.0 million of the convertible senior notes were issued to related parties and are separately presented on the consolidated balance sheets (see Note 21, *Related Party Transactions*). The net proceeds from the offering, after deducting debt issuance costs, were $112.8 million. The debt issuance costs were recorded as a debt discount and are being amortized to interest expense over the contractual term of the convertible senior notes.

Each $1,000 of principal of the convertible senior notes is initially convertible into 30.3030 shares of the Company's common stock, which is equivalent to an initial conversion price of $33.00 per share, subject to adjustment upon the occurrence of specified events related to dividends, tender offers or exchange offers. Holders of the convertible senior notes may convert their convertible senior notes at their option at any time up to and including the second scheduled trading day prior to maturity. If certain events that would constitute a make-whole fundamental change, such as significant changes in ownership, corporate structure or tradability of the Company's common stock, occur prior to the maturity date, the Company would increase the conversion rate for a holder who elects to convert its convertible senior notes in connection with such an event in certain circumstances. The maximum conversion rate is capped at 38.4615 shares for each $1,000 of principal of the convertible senior notes, which is equivalent to a minimum conversion price of $26.00 per share. The convertible senior notes do not have a cash conversion option. The convertible senior note holders may require the Company to repurchase their convertible senior notes for cash only under certain defined fundamental changes. On or after June 30, 2017, the convertible senior notes will be redeemable by the Company in the event that the closing price of the Company's common stock exceeds 200% of the conversion price for 45 consecutive trading days ending within three trading days of such redemption notice at a redemption price of par plus accrued and unpaid interest to, but excluding, the redemption date. The Company was in compliance with all debt covenants as of December 31, 2015.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Solar Bonds

In October 2014, the Company commenced issuing Solar Bonds, which are senior unsecured obligations that are structurally subordinate to the indebtedness and other liabilities of the Company's subsidiaries. Solar Bonds have been issued under multiple series that have various fixed terms and interest rates. In September 2015, the Company commenced issuing Solar Bonds with variable interest rates that reset quarterly and that can be redeemed quarterly at the option of the bondholder or the Company, with 30 days' advance notice. The Company intends to continue to issue Solar Bonds from time to time depending on market conditions. In March 2015, Space Exploration Technologies Corporation, or SpaceX, purchased $90.0 million in aggregate principal amount of 2.00% Solar Bonds due in March 2016. In June 2015, SpaceX purchased an additional $75.0 million in aggregate principal amount of 2.00% Solar Bonds due in June 2016. SpaceX is considered a related party, the Company has also issued Solar Bonds to other related parties and such Solar Bonds are separately presented on the consolidated balance sheets (see Note 21, *Related Party Transactions*). The Company was in compliance with all debt covenants as of December 31, 2015.

Non-Recourse Debt Facilities:

Term Loan Assumed From Silevo Acquisition

Through the Silevo acquisition, the Company assumed a pre-existing term loan with an outstanding principal balance of $9.1 million. The term loan bore interest at a fixed rate of 7.8% per annum and was denominated in the Chinese Yuan. The term loan was a liability of a subsidiary of Silevo only and was non-recourse to the Company and its other subsidiaries. In June 2015, the Company fully paid-off the term loan.

Term Loan Due in September 2015

In March 2015, a subsidiary of the Company entered into an agreement with a bank for a term loan of $79.0 million. The term loan bore interest at an annual rate of, at the Company's option, (a) 3.50% plus LIBOR or (b) 3.50% plus the highest of (i) the Federal Funds Rate plus 0.50%, (ii) Bank of America's published "prime rate" or (iii) LIBOR plus 1.00%. The term loan was secured by certain assets and cash flows of certain subsidiaries of the Company and was non-recourse to the Company's other assets or cash flows. On May 4, 2015, the Company fully paid-off the term loan using a portion of the proceeds from the revolving aggregation credit facility (see below).

Term Loan Due in May 2016

On May 23, 2014, a subsidiary of the Company entered into an agreement with a syndicate of banks for a term loan of $125.0 million. The term loan bears interest at an annual rate of 3.00% to 4.00%, depending on the cumulative period the term loan has been outstanding, plus LIBOR or, at the Company's option, plus the highest of (i) the Federal Funds Rate plus 0.50%, (ii) Bank of America's published "prime rate" or (iii) LIBOR plus 1.00%. The term loan is secured by certain assets and cash flows of the subsidiary and is non-recourse to the Company's other assets or cash flows. The Company was in compliance with all financial covenants as of December 31, 2015.

Term Loan Due in December 2016

On February 4, 2014, a subsidiary of the Company entered into an agreement with a syndicate of banks for a term loan of $100.0 million. On February 20, 2014, the agreement was amended to increase the maximum term loan availability to $220.0 million. On March 20, 2014, the agreement was further amended to increase the maximum term loan availability to $250.0 million. The term loan bears interest at an annual rate of LIBOR plus 3.25% or, at the Company's option, 3.25% plus the highest of (i) the Federal Funds Rate plus 0.50%, (ii) Bank of America's published "prime rate" or (iii) LIBOR plus 1.00%. In August 2015, the Company used $75.7 million of the proceeds from the issuance of the Solar Asset-backed Notes, Series 2015-1, to partially prepay the principal outstanding under the term loan (see below). The term loan is secured by the assets and cash flows of the subsidiary and is non-recourse to the Company's other assets. The Company was in compliance with all financial covenants as of December 31, 2015.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

MyPower Revolving Credit Facility

On January 9, 2015, a subsidiary of the Company entered into a $200.0 million revolving credit agreement with a syndicate of banks to obtain funding for the MyPower customer loan program. The MyPower revolving credit facility initially provided up to $160.0 million of Class A notes and up to $40.0 million of Class B notes. On December 16, 2015, the committed amount under the Class A notes was increased to $200.0 million. The Class A notes bear interest at an annual rate of (i) for the first $160.0 million, 2.50% and (ii) for the remaining $40.0 million, 3.00%; in each case, plus (a) the commercial paper rate or (b) 1.50% plus adjusted LIBOR. The Class B notes bear interest at an annual rate of 5.00% plus LIBOR. The fee for undrawn commitments under the Class A notes is 0.50% per annum for the first $160.0 million of undrawn commitments and 0.75% per annum for the remaining $40.0 million of undrawn commitments, if any. The fee for undrawn commitments under the Class B notes is 0.50% per annum. The MyPower revolving credit facility is secured by the payments owed to the Company or its subsidiaries under MyPower customer loans and is non-recourse to the Company's other assets. The Company was in compliance with all financial covenants as of December 31, 2015.

The Company has entered into forward interest rate swaps, in order to fix the variable interest rate, for each draw under the MyPower revolving credit facility. The Company accounts for the interest rate swaps as non-hedging derivatives (see Note 2, *Summary of Significant Accounting Policies and Procedures*).

Revolving Aggregation Credit Facility

On May 4, 2015, a subsidiary of the Company entered into an agreement with a syndicate of banks for a revolving aggregation credit facility with a total committed amount of $500.0 million. On the same date, the subsidiary drew $113.1 million under the revolving aggregation credit facility and used a portion of the proceeds to fully pay-off the term loan due in September 2015 (see above). On July 13, 2015, the total committed amount was increased to $650.0 million. The revolving aggregation credit facility bears interest at an annual rate of 2.75% plus (i) for commercial paper loans, the commercial paper rate and (ii) for LIBOR loans, at the Company's option, three-month LIBOR or daily LIBOR. The revolving aggregation credit facility is secured by certain assets and cash flows of certain subsidiaries of the Company and is non-recourse to the Company's other assets. The Company was in compliance with all financial covenants as of December 31, 2015.

The Company has entered into forward interest rate swaps, in order to fix the variable interest rate, for each draw under the revolving aggregation credit facility. The Company accounts for the interest rate swaps as non-hedging derivatives (see Note 2, *Summary of Significant Accounting Policies and Procedures*).

Solar Asset-backed Notes, Series 2013-1

The Company has structured and entered into various solar asset-backed note securitization transactions pursuant to its financial strategy of monetizing solar assets at the lowest cost of capital.

In November 2013, the Company pooled and transferred qualifying solar energy systems and the associated customer contracts into a special purpose entity, or SPE, and issued $54.4 million in aggregate principal of Solar Asset-backed Notes, Series 2013-1, backed by these solar assets to certain investors. The SPE is wholly owned by the Company and is consolidated in the Company's financial statements. Accordingly, the Company did not recognize a gain or loss on the transfer of these solar assets. As of December 31, 2015, these solar assets had a carrying value of $138.5 million and are included under solar energy systems, leased and to be leased — net, in the consolidated balance sheets. The Solar Asset-backed Notes were issued at a discount of 0.05%. The cash flows generated by these solar assets are used to service the monthly principal and interest payments on the Solar Asset-backed Notes and satisfy the SPE's expenses, and any remaining cash is distributed to a wholly owned subsidiary of the Company. The Company recognizes revenue earned from the associated customer contracts in accordance with the Company's revenue recognition policy. The assets and cash flows generated by the qualifying solar energy systems are not available to the other creditors of the Company, and the creditors of the SPE, including the Solar Asset-backed Note holders, have no recourse to the Company's other assets. The Company contracted with the SPE to provide operations and maintenance and administrative services for the qualifying solar energy systems. The Company was in compliance with all financial covenants as of December 31, 2015.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

In connection with the pooling of the assets that were transferred to the SPE in November 2013, the Company terminated a lease pass-through arrangement with an investor. The lease pass-through arrangement had been accounted for as a borrowing and any amounts outstanding from the lease pass-through arrangement were recorded as a lease pass-through financing obligation. The balance that was then outstanding from the lease pass-through arrangement was $56.4 million. The Company paid the investor an aggregate of $40.2 million, and the remaining balance is to be paid over time. The remaining balance is paid using the net cash flows generated by the same assets previously leased under the lease pass-through arrangement, after payment of the principal and interest on the Solar Asset-backed Notes and expenses related to the assets and the Notes, including asset management fees, custodial fees and trustee fees, and was contractually documented as a right to participate in future cash flows of the SPE. This right to participate in future residual cash flows generated by the assets of the SPE has been recorded as a component of other liabilities and deferred credits for the noncurrent portion and as a component of accrued and other current liabilities for the current portion under the caption "participation interest." The Company accounted for the participation interest as a liability because the investor has no voting or management rights in the SPE, the participation interest would terminate upon the investor achieving a specified return and the investor has the option to put the participation interest to the Company on August 3, 2021 for the amount necessary for the investor to achieve the specified return, which would require the Company to settle the participation interest in cash. In addition, under the terms of the participation interest, the Company has the option to purchase the participation interest from the investor for the amount necessary for the investor to achieve the specified return.

Solar Asset-backed Notes, 2014-1

In April 2014, the Company pooled and transferred qualifying solar energy systems and the associated customer contracts into a SPE and issued $70.2 million in aggregate principal of Solar Asset-backed Notes, Series 2014-1, backed by these solar assets to certain investors. The SPE is wholly owned by the Company and is consolidated in the Company's financial statements. Accordingly, the Company did not recognize a gain or loss on the transfer of these solar assets. As of December 31, 2015, these solar assets had a carrying value of $129.6 million and are included under solar energy systems, leased and to be leased — net, in the consolidated balance sheets. The Solar Asset-backed Notes were issued at a discount of 0.01%. The cash flows generated by these solar assets are used to service the monthly principal and interest payments on the Solar Asset-backed Notes and satisfy the SPE's expenses, and any remaining cash is distributed to a wholly owned subsidiary of the Company. The Company recognizes revenue earned from the associated customer contracts in accordance with the Company's revenue recognition policy. The assets and cash flows generated by the qualifying solar energy systems are not available to the other creditors of the Company, and the creditors of the SPE, including the Solar Asset-backed Note holders, have no recourse to the Company's other assets. The Company contracted with the SPE to provide operations and maintenance and administrative services for the qualifying solar energy systems. The Company was in compliance with all financial covenants as of December 31, 2015.

In connection with the transfer of the assets into the SPE in April 2014, the Company terminated a lease pass-through arrangement with an entity that is a partnership between the Company and an investor. The partnership is a VIE that is consolidated by the Company as the primary beneficiary. To settle the associated lease pass-through financing obligation, the partnership distributed $74.5 million to the investor, including amounts previously accrued for distribution, and amended the expected future distributions to the investor. Additionally, the contractual documents of the partnership were amended to grant the investor the right to put its interest in the partnership back to the partnership. Accordingly, the carrying value of the investor's interest in the partnership was reclassified from noncontrolling interests in subsidiaries to redeemable noncontrolling interests in subsidiaries in the consolidated balance sheets.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Solar Asset-backed Notes, Series 2014-2

In July 2014, the Company pooled and transferred qualifying solar energy systems and the associated customer contracts into a SPE and issued $160.0 million in aggregate principal of Solar Asset-backed Notes, Series 2014-2, Class A, and $41.5 million in aggregate principal of Solar Asset-backed Notes, Series 2014-2, Class B, to certain investors. The SPE is wholly owned by the Company and is consolidated in the Company's financial statements. Accordingly, the Company did not recognize a gain or loss on the transfer of these solar assets. As of December 31, 2015, these solar assets had a carrying value of $275.6 million and are included under solar energy systems, leased and to be leased — net, in the consolidated balance sheets. The Solar Asset-backed Notes were issued at a discount of 0.01%. These solar assets and the associated customer contracts are leased to an investor under a lease pass-through arrangement that the Company has accounted for as a borrowing. The rent paid by the investor under the lease pass-through arrangement is used (and, following the expiration of the lease pass-through arrangement, the cash generated by these solar assets will be used) to service the monthly principal and interest payments on the Solar Asset-backed Notes and satisfy the SPE's expenses, and any remaining cash is distributed to a wholly owned subsidiary of the Company. The Company recognizes revenue earned from the associated customer contracts in accordance with the Company's revenue recognition policy. The assets and cash flows generated by these solar assets are not available to the other creditors of the Company, and the creditors of the SPE, including the Solar Asset-backed Note holders, have no recourse to the Company's other assets. The Company contracted with the SPE to provide operations and maintenance and administrative services for the qualifying solar energy systems. The Company was in compliance with all financial covenants as of December 31, 2015.

In connection with the transfer of the assets into the SPE in July 2014, the Company paid $129.3 million to fully settle the term loan obtained on June 7, 2013 that was due in June 2015 (see below).

Solar Asset-backed Notes, Series 2015-1

In August 2015, the Company pooled and transferred its interests in certain financing funds into a SPE and issued $103.5 million in aggregate principal of Solar Asset-backed Notes, Series 2015-1, Class A, and $20.0 million in aggregate principal of Solar Asset-backed Notes, Series 2015-1, Class B, to certain investors. The Company used a portion of the proceeds to partially prepay the principal outstanding under the term loan due in December 2016 (see above). The SPE is wholly owned by the Company and is consolidated in the Company's financial statements. Accordingly, the Company did not recognize a gain or loss on the transfer of these interests and continues to consolidate the underlying financing funds (see Note 12, *VIE Arrangements*). The Solar Asset-backed Notes were issued at a discount of 0.05% for Class A and 1.46% for Class B. The cash distributed by the underlying financing funds to the SPE are used to service the semi-annual principal and interest payments on the Solar Asset-backed Notes and satisfy the SPE's expenses, and any remaining cash is distributed to a wholly owned subsidiary of the Company. The SPE's assets and cash flows are not available to the other creditors of the Company, and the creditors of the SPE, including the Solar Asset-backed Note holders, have no recourse to the Company's other assets. The Company was in compliance with all financial covenants as of December 31, 2015.

Working Capital Financing

On May 26, 2010, a subsidiary of the Company entered into a financing agreement with a bank to obtain funding for working capital. The amount available to be borrowed under the financing agreement was determined based on the present value of expected future lease receipts from solar energy systems owned by the subsidiary and leased to customers, up to a maximum of $16.3 million. The working capital financing was funded in four tranches and was available for draw-down through March 31, 2011. Each tranche bore interest at an annual rate of 2.00% plus the swap rate applicable to the average life of the scheduled lease receipts for the tranche. The working capital financing was secured by substantially all of the subsidiary's assets and was nonrecourse to the Company's other assets. On July 2, 2014, the Company fully repaid the outstanding balance of and terminated the working capital financing, recognizing a loss on debt extinguishment of $0.4 million within other expense – net in the consolidated statements of operations.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Credit Facility for SolarStrong

On November 21, 2011, a subsidiary of the Company entered into an agreement with a bank for a credit facility of up to $350.0 million. The credit facility was to be used to partially fund the Company's SolarStrong initiative, which was a five-year plan to build solar energy systems for privatized U.S. military housing communities across the country. The credit facility was to be drawn-down in tranches, with the interest rates determined when the amounts were drawn-down. The credit facility was secured by the assets of the SolarStrong initiative and was non-recourse to the Company's other assets. On December 24, 2014, the Company paid $5.5 million to fully settle the outstanding balance of and terminate the credit facility due to the unfavorable financing economics of this facility. As a result, the Company recognized a loss on debt extinguishment of $2.6 million within other expense – net in the consolidated statements of operations.

Term Loan Due in June 2015

On June 7, 2013, a subsidiary of the Company entered into an agreement with a syndicate of banks for a term loan of $100.0 million. On January 6, 2014, the agreement was amended to increase the maximum term loan availability to $158.0 million. Each tranche of the term loan bore interest at an annual rate of LIBOR plus 3.25%. The term loan was secured by the assets and cash flows of the subsidiary and was non-recourse to the Company's other assets. On July 31, 2014, the Company fully repaid the outstanding balance of and terminated the term loan in connection with the issuance of Solar Asset-backed Notes, Series 2014-2 (see above). Upon the termination of the term loan, the Company recognized a loss on debt extinguishment of $1.5 million within other expense – net in the consolidated statements of operations.

Schedule of Principal Maturities of Debt

The future scheduled principal maturities of debt as of December 31, 2015 were as follows (in thousands):

	Recourse Debt Excluding Convertible Senior Notes	Non-Recourse Debt	Convertible Senior Notes	Total
2016	$ 213,570	$ 161,567	$ —	$ 375,137
2017	350,584	684,072	—	1,034,656
2018	14,929	15,743	230,000	260,672
2019	422	16,548	566,000	582,970
2020	14,992	17,800	113,000	145,792
Thereafter	8,000	346,519	—	354,519
Total	$ 602,497	$ 1,242,249	$ 909,000	$ 2,753,746

The convertible senior notes do not have a cash conversion option and are therefore expected to be settled in shares of the Company's common stock.

12. VIE Arrangements

The Company has entered into various arrangements with investors to facilitate funding and monetization of solar energy systems. These arrangements include those described in this Note 12, *VIE Arrangements*, as well as those described in Note 13, *Lease Pass-Through Financing Obligation*, Note 14, *Sale-Leaseback Arrangements*, and Note 15, *Sale-Leaseback Financing Obligation*.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Fund Arrangements

Wholly owned subsidiaries of the Company and fund investors formed and contributed cash or assets to various solar financing funds and entered into related agreements. Additionally, the Company acquired the assets of a fund through a business combination in September 2013 and assumed the related contractual arrangements. The following table shows the number of funds by investor classification, carrying value of the solar energy systems in the funds, total investor contributions received and undrawn investor contributions as of December 31, 2015 (in thousands, except for number of funds, and unaudited):

Investor Classification	Number of Funds	Total Investor Contributions Received	Undrawn Investor Contributions	Carrying Value of Solar Energy Systems
Financial institutions	22	$ 1,492,790	$ 146,662	$1,752,262
Corporations	6	753,386	70,996	781,062
Utilities	4	255,869	58,051	242,826
Other investors	1	1,788	—	3,213
Total	33	$ 2,503,833	$ 275,709	$2,779,363

The Company has determined that the funds are VIEs and it is the primary beneficiary of these VIEs by reference to the power and benefits criterion under ASC 810, *Consolidation*. The Company has considered the provisions within the contractual agreements, which grant it power to manage and make decisions that affect the operation of these VIEs, including determining the solar energy systems and associated customer contracts to be sold or contributed to these VIEs and the redeployment of solar energy systems. The Company considers that the rights granted to the fund investors under the contractual agreements are more protective in nature rather than participating.

As the primary beneficiary of these VIEs, the Company consolidates in its financial statements the financial position, results of operations and cash flows of these VIEs, and all intercompany balances and transactions between the Company and these VIEs are eliminated in the consolidated financial statements.

Cash distributions of income and other receipts by a fund, net of agreed upon expenses, estimated expenses, tax benefits and detriments of income and loss and tax credits, are allocated to the fund investor and the Company's subsidiary as specified in contractual agreements.

Generally, the Company's subsidiary has the option to acquire the fund investor's interest in the fund for an amount based on the market value of the fund or the formula specified in the contractual agreements.

On March 31, 2014, the Company acquired a fund investor's interest in one fund for total consideration of $0.5 million.

As of December 31, 2015 and 2014, the Company was contractually required to make payments to a fund investor in order to ensure the investor is projected to achieve a specified minimum return annually. The amounts of any potential future payments under this guarantee are dependent on the amounts and timing of future distributions to the investor from the fund, the tax benefits that accrue to the investor from the fund's activities and the amount and timing of the Company's purchase of the investor's interest in the fund or the amount and timing of the distributions to the investor upon liquidation of the fund. Due to uncertainties associated with estimating the amount and timing of distributions to the investor and the possibility and timing of the liquidation of the fund, the Company is unable to determine the potential maximum future payments that it would have to make under this guarantee.

Upon the sale or liquidation of a fund, distributions would occur in the order and priority specified in the contractual agreements.

Pursuant to management services, maintenance and warranty arrangements, the Company has been contracted to provide services to the funds, such as operations and maintenance support, accounting, lease servicing and performance reporting. In some instances, the Company has guaranteed payments to the investors as specified in the contractual agreements. A fund's creditors have no recourse to the general credit of the Company or to that of other funds. None of the assets of the funds had been pledged as collateral for their obligations.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

The Company presents the solar energy systems in the VIEs under solar energy systems, leased and to be leased – net in the consolidated balance sheets. The aggregate carrying values of the VIEs' assets and liabilities, after elimination of intercompany transactions and balances, in the consolidated balance sheets were as follows (in thousands):

	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 32,105	$ 26,419
Restricted cash	44	106
Accounts receivable - net	10,116	6,769
Rebates receivable	6,220	25,397
Prepaid expenses and other current assets	1,740	615
Total current assets	50,225	59,306
Solar energy systems, leased and to be leased - net	2,779,363	1,581,459
Other assets	11,204	4,080
Total assets	$ 2,840,792	$ 1,644,845
Liabilities		
Current liabilities:		
Distributions payable to noncontrolling interests and redeemable noncontrolling interests	$ 26,769	$ 8,552
Current portion of deferred U.S. Treasury grant income	6,506	6,502
Accrued and other current liabilities	598	336
Customer deposits	2,928	6,405
Current portion of deferred revenue	24,794	16,746
Total current liabilities	61,595	38,541
Deferred revenue, net of current portion	308,798	256,200
Deferred U.S. Treasury grant income, net of current portion	164,191	170,548
Other liabilities and deferred credits	28,460	10,825
Total liabilities	$ 563,044	$ 476,114

The Company is contractually obligated to make certain fund investors whole for losses that they may suffer in certain limited circumstances resulting from the disallowance or recapture of ITCs or U.S. Treasury grants, including in the event that the U.S. Treasury Department awards ITCs or U.S. Treasury grants for the solar energy systems in the funds that are less than the amounts initially anticipated. The Company accounts for distributions due to the fund investors arising from a reduction of anticipated ITCs or U.S. Treasury grants received under distributions payable to noncontrolling interests and redeemable noncontrolling interests in the consolidated balance sheets. As of December 31, 2015, the Company had accrued $2.7 million for this obligation.

Silevo's Joint Venture in China

The Company, through its subsidiary, Silevo, operates a joint venture, Silevo China Company Limited, or the JV, with three other Chinese legal entities, or the JV Partners, to develop, manufacture and market high performance solar cells. As of December 31, 2015, Silevo owned approximately 65.7% of the outstanding capital of the JV, and the JV Partners owned the remaining interests. Silevo has a Manufacturing Services and Technology Licensing Agreement with the JV to acquire solar cells on a "cost-plus" basis. The JV is required to obtain Silevo's consent to sell products to any third-party. The agreement had an initial term of one year and automatically renews for successive one-year periods.

The Company has determined that the JV is a VIE and that Silevo is the primary beneficiary of the JV since the variable interests held by Silevo empower it to direct the activities that most significantly impact the joint venture's

economic performance. In reaching this determination, the Company considered the significant control exercised by Silevo over the JV's board of directors, management and daily operations.

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Silevo had the right to acquire the JV Partners' interests in the JV at any time before August 2016. The JV Partners had the right to sell all or part of their interests in the JV to Silevo if the JV did not meet certain conditions set out in the JV contract, which included meeting set production targets within a specified time frame. The JV did not meet some of those targets, and as such, the option became exercisable. The amount that the Company would pay the JV Partners upon the exercise of either option is equal to the JV Partners' accumulated capital contributions plus interest at specified rates. As of December 31, 2015, this amount was $13.8 million. During the quarter ended June 30, 2015, the JV Partners informed the Company of their intention to exercise their put option. The Company has initiated the process of settling the amounts payable to the JV partners and transferring the JV Partners' shares to the Company, and expects to finalize the settlement process and transfer of the shares prior to March 31, 2016. The JV is not allowed to make a profit distribution to investors prior to the full exit of the JV Partners from their investments in the JV.

Since Silevo has been determined to be the primary beneficiary of the JV, the JV's assets, liabilities and results of operations are included in the Company's consolidated financial statements. The JV Partners' interests in the JV are reflected in redeemable noncontrolling interests on the consolidated balance sheets. The JV Partners' interests in the JV is recorded at fair value, which was equal to the value of the JV Partners' put option to sell their interests in the JV to Silevo (see above).

The aggregate carrying values of the JV's assets and liabilities in the consolidated balance sheets were as follows (in thousands):

	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 1,432	$ 1,401
Restricted cash	478	—
Accounts receivable, net	151	—
Inventories	1,000	614
Prepaid expenses and other current assets	973	1,224
Total current assets	4,034	3,239
Property, plant and equipment - net	21,960	24,286
Other assets	96	—
Total assets	$ 26,090	$ 27,525
Liabilities		
Current liabilities:		
Accounts payable	1,954	$ 2,748
Accrued and other current liabilities	1,226	633
Current portion of long-term debt	—	9,134
Total current liabilities	3,180	12,515
Total liabilities	$ 3,180	$ 12,515

13. Lease Pass-Through Financing Obligation

Through December 31, 2015, the Company had entered into eight transactions referred to as "lease pass-through fund arrangements." Under these arrangements, the Company's wholly owned subsidiaries finance the cost of solar energy systems with investors through arrangements contractually structured as master leases for an initial term ranging between 10 and 25 years. These solar energy systems are subject to lease or power purchase agreements with customers with an initial term not exceeding 20 years. These solar energy systems are included under solar energy systems, leased and to be leased – net in the consolidated balance sheets. As discussed in Note 11, *Indebtedness,* in November 2013, in connection with the Company pooling assets for purposes of issuing Solar Asset-backed Notes, the Company terminated a lease pass-through fund arrangement with an investor.

The cost of the solar energy systems under the lease pass-through fund arrangements as of December 31, 2015 and 2014 was $670.5 million and $540.0 million, respectively. The accumulated depreciation related to these assets as of December 31, 2015 and 2014 was $52.8 million and $34.1 million, respectively. The total lease pass-through financing obligation as of December 31, 2015 and 2014 was $89.5 million and $88.7 million, respectively, of which $34.0 million and $29.2 million, respectively, was classified as current liabilities.

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Notes to Consolidated Financial Statements (continued)

Under lease pass-through fund arrangements, the investors make a large upfront payment to the lessor, which is a subsidiary of the Company, and in some cases, subsequent periodic payments. The Company allocates a portion of the aggregate payments received from the investors to the estimated fair value of the assigned ITCs, and the balance to the future customer lease payments that are also assigned to the investors. The estimated fair value of the ITCs are determined by discounting the estimated cash flows impact of the ITCs using an appropriate discount rate that reflects a market interest rate. The Company has an obligation to ensure the solar energy system is in service and operational for a term of five years to avoid any recapture of the ITCs. The amounts allocated to ITCs are initially recorded as deferred revenue on the consolidated balance sheets, and subsequently, one-fifth of the amounts allocated to ITCs is recognized as revenue from operating leases and solar energy systems incentives on the consolidated statements of operations on each anniversary of the solar energy system's placed in service date over the next five years.

The Company accounts for the residual of the payments received from the investors as a borrowing by recording the proceeds received as a lease pass-through financing obligation, which is repaid from U.S. Treasury grants (where applicable), customer payments and incentive rebates that are expected to be received by the investors. Under this approach, the Company continues to account for the arrangement with the customers in its consolidated financial statements, whether the cash generated from the customer arrangements is received by the Company or paid directly to the investors. A portion of the amounts received by the investors from U.S. Treasury grants (where applicable), customer payments and incentive rebates is applied to reduce the lease pass-through financing obligation, and the balance is allocated to interest expense. The incentive rebates and customer payments are recognized into revenue consistent with the Company's revenue recognition accounting policy. The U.S. Treasury grants are initially recorded as deferred U.S. Treasury grants income and subsequently recognized as a reduction to depreciation expense, consistent with the Company's accounting policy for recognition of U.S. Treasury grants income. Interest is calculated on the lease pass-through financing obligation using the effective interest rate method. The effective interest rate is the interest rate that equates the present value of the cash amounts to be received by an investor over the master lease term with the present value of the cash amounts paid by the investor to the Company, adjusted for any payments made by the Company. The lease pass-through financing obligation is non-recourse once the associated assets have been placed in service and all the customer arrangements have been assigned to the investors.

As of December 31, 2015, the future minimum lease payments to be received from the investors based on the solar energy systems currently under the lease pass-through fund arrangements, for each of the next five years and thereafter, were as follows (in thousands):

2016	26,698
2017	27,177
2018	26,780
2019	26,283
2020	26,246
Thereafter	134,521
Total	$ 267,705

For two of the lease pass-through fund arrangements, the Company's subsidiaries have pledged its assets to the investors as security for their obligations under the contractual agreements.

For each of the lease pass-through fund arrangements, the Company is required to comply with certain financial covenants specified in the contractual agreements, which the Company had met as of December 31, 2015.

Under the lease pass-through fund arrangements, the Company is responsible for any warranties, performance guarantees, accounting and performance reporting.

Under the lease pass-through fund arrangements, there is a one-time future lease payment reset mechanism that is set to occur after all of the solar energy systems are delivered and placed in service in a fund. This reset date occurs when the installed capacity of the solar energy systems and their in-service dates are known or on an agreed upon date. As part of this reset process, the lease prepayment is updated to reflect certain specified conditions as they exist at such date,

including the final installed capacity, cost and in-service dates of the solar energy systems. As a result of this reset process, the Company may be obligated to refund a portion of an investor's master lease prepayments or may be entitled to receive an additional master lease prepayment from an investor. Any additional master lease prepayments by an investor would be recorded as an additional lease pass-through financing obligation, while any refunds of master lease prepayments would reduce the lease pass-through financing obligation.

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14. Sale-Leaseback Arrangements

In 2010, the Company executed a sale-leaseback arrangement with an existing investor, under which a wholly owned subsidiary of the Company entered into a 15-year master leaseback arrangement. The assets sold to the investor were valued at $25.2 million. The Company's subsidiary leased the solar energy systems to end-user customers. The obligations of the Company's subsidiary to the investor are guaranteed by the Company and supported by a $0.25 million restricted cash escrow. Under this arrangement, the Company's subsidiary is responsible for services such as warranty support, accounting, lease servicing and performance reporting.

As of December 31, 2015 and 2014, the Company had contributed assets with a cost of $44.6 million to its wholly owned subsidiary that in turn sold the assets to a new investor and then executed a 15-year master leaseback agreement with the investor. Under this arrangement, the tax benefits from ITCs or Treasury grants in lieu of tax credits inure to the investor as the owner of the assets.

The Company has committed to make investors that have executed sale-leaseback arrangements with the Company whole for any reductions in the tax credit or U.S. Treasury awards resulting from changes in the tax basis submitted. The Company accrues any such payments due to these investors. As of December 31, 2015, no such amounts were due to these investors.

The Company has accounted for these sale-leaseback arrangements in accordance with the Company's accounting policy as described in Note 2, *Summary of Significant Accounting Policies and Procedures*.

15. Sale-Leaseback Financing Obligation

In November 2009, the Company entered into an arrangement with an investor to finance the development, construction and installation of a ground mounted solar energy system that was leased to a customer. The Company also entered into an agreement to sell the system to the investor for a cash consideration of $27.2 million, of which $23.7 million has been received as of December 31, 2015 and the balance of $3.5 million is receivable at the end of the lease period and accrues interest at an annual rate of 4.37%. Concurrent with the sale, a subsidiary of the Company entered into an agreement with the investor to lease back the solar energy system from the investor with lease payments being made on a quarterly basis. The Company's subsidiary has the option to purchase the system at the end of the lease term of 10 years for a price which is the greater of the fair market value or a predetermined agreed upon value. Additionally, the investor has the option to put its interest in the solar energy system to the Company within two years following the expiry of six years after placement in service of the system, for the amount that is the greater of the fair value of the system or the predetermined agreed upon value. As a result of these put and call options, the Company has concluded that it has a continuing involvement with the solar energy system.

The Company has determined that the ground mounted solar energy system qualifies as integral equipment and therefore as a real estate transaction under ASC 360-20, *Real Estate Sales,* and has been accounted for as a financing. Under the financing method, the receipts from the investor are reflected as a sale-leaseback financing obligation on the consolidated balance sheets, and the Company retains the solar energy system asset on the consolidated balance sheets within solar energy systems and depreciates the solar energy system over its estimated useful life of 30 years. The Company also continues to report all of the results of the operations of the system, with the revenue and expenses from the system operations being presented on the consolidated statements of operations on a "gross" basis. As of December 31, 2015, the balance of the sale-leaseback financing obligation outstanding was $13.9 million, of which $0.5 million has been classified as current and the balance of $13.4 million has been classified as noncurrent. As of December 31, 2014, the balance of the sale-leaseback financing obligation outstanding was $14.3 million, of which $0.4 million has been classified as current and the balance of $13.9 million has been classified as noncurrent.

As of December 31, 2015, future minimum annual rentals to be received from the customer for each of the next five years and thereafter are as follows (in thousands):

2016	485
2017	494
2018	504

2019	514
2020	524
Thereafter	2,204
Total	$ 4,725

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Notes to Consolidated Financial Statements (continued)

The amounts in the table above are also included as part of the noncancelable operating lease payments from customers disclosed in Note 5, *Noncancelable Operating Lease Payments Receivable.*

As of December 31, 2015, future minimum annual payments to be paid to the investor under the financing arrangement for each of the next five years and thereafter are as follows (in thousands):

2016	1,264
2017	1,270
2018	1,277
2019	1,284
2020	—
Thereafter	—
Total	$ 5,095

The obligations of the Company's subsidiary to the investor are guaranteed by the Company and supported by a $0.25 million restricted cash escrow.

16. Redeemable Noncontrolling Interests in Subsidiaries

Noncontrolling interests in subsidiaries that are redeemable at the option of the holder are classified as redeemable noncontrolling interests in subsidiaries between liabilities and stockholders' equity in the consolidated balance sheets. The redeemable noncontrolling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method for the VIE funds or allocation of share of income or losses in other subsidiaries subsequent to initial recognition, however, the noncontrolling interests balance cannot be less than the estimated redemption value. The activity of the redeemable noncontrolling interests in subsidiaries balance was as follows (in thousands):

Balance at January 1, 2013	$ 12,827
Contributions from noncontrolling interests	172,913
Net loss	(118,854)
Noncontrolling interest arising from acquisition of Paramount Energy	549
Distributions to noncontrolling interests	(22,726)
Balance at December 31, 2013	44,709
Contributions from redeemable noncontrolling interests	260,492
Net loss	(141,072)
Distributions to redeemable noncontrolling interests	(14,313)
Transfers from noncontrolling interests in subsidiaries	25,248
Redeemable noncontrolling interests arising from acquisition of Silevo	14,174
Acquisition of redeemable noncontrolling interests in subsidiaries	(2,450)
Balance at December 31, 2014	186,788
Contributions from redeemable noncontrolling interests	415,493
Net loss	(258,493)
Distributions to redeemable noncontrolling interests	(22,853)
Balance at December 31, 2015	$ 320,935

17. Stockholders' Equity

Common Stock

On May 8, 2013, a fund investor exercised its warrants to purchase 1,485,010 shares of the Company's common stock for $8.0 million.

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On September 6, 2013, the Company issued 3,674,565 shares of its common stock pursuant to its acquisition of the assets of Paramount Energy.

On October 21, 2013, the Company issued 3,910,000 shares of its common stock in a secondary public offering for aggregate proceeds of $174.1 million, net of underwriting discounts and offering expenses.

On December 11, 2013, the Company issued 2,751,782 shares of its common stock pursuant to its acquisition of Zep Solar.

On September 23, 2014, the Company issued 2,284,070 shares of its common stock pursuant to its acquisition of Silevo (see Note 3, *Acquisitions*).

Shares Reserved for Future Issuance

The Company had reserved shares of common stock for future issuance as follows (in thousands):

	As of December 31,	
	2015	2014
Stock-based compensation plans:		
Awards available for grant	3,517	7,919
Awards outstanding	21,891	14,979
Employee Stock Purchase Plan	1,300	1,300
Convertible senior notes outstanding	18,267	13,920
Total	$ 44,975	38,118

18. Equity Award Plans

Stock Options

Under the Company's 2012 Equity Incentive Plan, the Company may grant incentive stock options and non-statutory stock options for common stock to employees, directors and consultants. Stock options may be granted at an exercise price per share not less than 100% of the fair market value per share on the grant date. If an incentive stock option is granted to a 10% or greater stockholder, then the exercise price per share shall not be less than 110% of the fair market value per share on the grant date. Stock options granted are exercisable over a maximum term of 10 years from the date of grant and generally vest over a period of four years.

In September 2012, the Company adopted a director compensation plan for future non-employee directors. Under the director compensation plan, each individual who joins the board of directors as a non-employee director following the adoption of the plan receives an initial stock option grant to purchase 30,000 shares of common stock at the time of initial election or appointment and additional triennial stock option grants to purchase 15,000 shares of common stock, as well as an annual cash retainer of $15,000, all of which are subject to continued service on the board of directors. Such non-employee directors who serve on committees of the board of directors receive various specified additional equity awards and cash retainers.

Effective as of June 2015, the Company revised the director compensation plan, pursuant to which non-employee directors receive an initial stock option grant to purchase 33,333 shares of common stock at the time of initial election or appointment and additional triennial stock option grants to purchase 30,000 shares of common stock, as well as an annual cash retainer of $20,000, all of which are subject to continued service on the board of directors. Such non-employee directors who serve on committees of the board of directors receive various specified additional equity awards and cash retainers.

Pursuant to the acquisition of Zep Solar, the Company assumed the Zep Solar, Inc. 2010 Equity Incentive Plan, or Zep Solar Plan, and issued fully vested stock options to purchase 303,151 shares of the Company's common stock to

replace certain fully vested stock options originally issued by Zep Solar. No additional equity awards were or will be granted under the Zep Solar Plan.

On September 15, 2015, the Chief Executive Officer and the Chief Technology Officer, the Company founders, were granted non-statutory stock option awards, or Founder Awards, with both market and performance vesting conditions. The exercise price per share of the Founder Awards is $48.97. The Chief Executive Officer's Founder Award covers up to 3.0 million shares of the Company's common stock, and the Chief Technology Officer's Founder Award covers up to 2.0 million shares of the Company's common stock. The Founder Awards have a maximum term of 10 years from the date of grant and vest in 10 equal tranches based on

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Notes to Consolidated Financial Statements (continued)

the achievement of specified operational goals and the 90-trading day average price of the Company's common stock achieving certain targets on specified measurement dates. In the event of a change in control or a termination of employment, all vesting under the related Founder Award would cease, and any unvested portion would be cancelled.

A summary of stock option activity is as follows (in thousands, except per share amounts):

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding - January 1, 2013	14,903	$ 4.80	7.67	$ 107,653
Granted (weighted-average fair value of $27.55)	4,364	39.02		
Issued in connection with a business acquisition (weighted-average fair value of $49.13)	303	1.97		
Exercised	(4,260)	3.65		149,653
Canceled	(1,361)	15.30		
Outstanding - December 31, 2013	13,949	14.77	7.52	586,740
Granted (weighted-average fair value of $47.45)	5,544	65.69		
Exercised	(3,176)	6.38		185,822
Canceled	(2,367)	38.51		
Outstanding - December 31, 2014	13,950	32.89	7.64	342,293
Granted (weighted-average fair value of $31.24)	6,448	49.67		
Exercised	(951)	12.25		37,929
Canceled	(1,132)	56.07		
Outstanding - December 31, 2015	18,315	$ 38.43	7.74	$ 293,855
Options vested and exercisable - December 31, 2013	6,696	$ 4.62	6.54	$ 349,523
Options vested and exercisable - December 31, 2014	6,537	$ 12.72	6.30	$ 272,140
Options vested and exercisable - December 31, 2015	8,029	$ 21.53	5.88	$ 258,310
Options vested and expected to vest - December 31, 2013	12,828	$ 13.53	7.41	$ 555,412
Options vested and expected to vest - December 31, 2014	12,423	$ 30.15	7.46	$ 333,813
Options vested and expected to vest - December 31, 2015	15,184	$ 35.94	7.37	$ 287,673

As of December 31, 2015, 67.7% of the non-vested stock options outstanding had a performance feature that is required to be satisfied before they become vested and exercisable, including 5.0 million non-vested stock options outstanding under the Founder Awards. The grant date fair market value of the stock options that vested in 2015, 2014 and 2013 was $109.7 million, $54.9 million and $28.3 million, respectively.

As of December 31, 2015 and 2014, there was $265.3 million and $242.9 million, respectively, of total unrecognized stock-based compensation expense, net of estimated forfeitures, related to non-vested stock options, which are expected to be recognized over the weighted-average period of 5.56 years and 2.76 years, respectively; including $118.8 million as of December 31, 2015 from the Founder Awards.

Under ASC 718, the Company estimates the fair value of stock options granted on each grant date using the Black-Scholes option valuation model, except for the Founder Awards for which the Company uses a Monte Carlo simulation, and applies the straight-line method of expense attribution. The fair values were estimated on each grant date with the following weighted-average assumptions:

	Year Ended December 31,		
	2015	2014	2013
Dividend yield	0%	0%	0%
Annual risk-free rate of return	2.14%	1.95%	1.45%
Expected volatility	65.76%	83.66%	92.86%
Expected term (years)	7.02	6.25	6.06

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Notes to Consolidated Financial Statements (continued)

The expected volatility was calculated based on the average historical volatilities of the Company and publicly traded peer companies determined by the Company. The risk-free interest rate used was based on the U.S. Treasury yield curve in effect at the time of grant for the expected term of the stock options to be valued. The expected dividend yield was zero, as the Company does not anticipate paying a dividend within the relevant time frame. The expected term has been estimated using the simplified method allowed under ASC 718.

Restricted Stock Units

The Company began granting restricted stock units, or RSUs, to employees, directors and consultants in 2012 under the Company's 2012 Equity Incentive Plan. A summary of RSU activity is as follows (in thousands, except per share amounts):

	Restricted Stock Units	Weighted-Average Fair Value
Outstanding - January 1, 2013	17	$ 18.48
Granted	17	35.00
Released	(14)	50.18
Outstanding - December 31, 2013	20	25.46
Granted	1,097	61.92
Released	(52)	60.81
Cancelled	(36)	64.79
Outstanding - December 31, 2014	1,029	61.16
Granted	3,332	47.99
Vested	(392)	60.19
Cancelled	(392)	56.29
Outstanding - December 31, 2015	3,577	$ 49.53
Expected to vest - December 31, 2015	2,741	$ 50.67

The grant date fair value of RSUs vested was $23.5 million, $3.2 million and $0.4 million for the years ended December 31, 2015, 2014 and 2013, respectively. Under ASC 718, the Company determines the fair value of RSUs granted on each grant date based on the fair value of the Company's common stock on the grant date and applies the straight-line method of expense attribution. As of December 31, 2015 and 2014, there was $121.5 million and $55.2 million, respectively, of total unrecognized stock-based compensation expense, net of estimated forfeitures, from RSUs, which are expected to be recognized over the weighted-average period of 3.31 years and 3.30 years, respectively.

Stock-Based Compensation Expense

As part of the requirements of ASC 718, the Company is required to estimate potential forfeitures of equity awards and adjust stock-based compensation expense accordingly. The estimate of forfeitures will be adjusted over the requisite service period to the extent that actual forfeitures differ, or are expected to differ, from such estimates. Changes in estimated forfeitures will be recognized in the period of change and will also impact the amount of stock-based compensation expense to be recognized in future periods.

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Notes to Consolidated Financial Statements (continued)

The amount of stock-based compensation expense recognized during the years ended December 31, 2015, 2014 and 2013 was $116.8 million, $88.9 million and $27.9 million, respectively. The amount of stock-based compensation expense that was capitalized is as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Capitalized under:			
Inventories	$ 226	$ 192	$ 433
Other assets	$ 3,136	$ 142	$ —
Property, plant and equipment - net	$ 2,997	$ 5,340	$ —
Solar energy systems, leased and to be leased - net	$ 24,075	$ 17,700	$ 6,576

Stock-based compensation expense was included in cost of revenue and operating expenses as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Total cost of revenue	$ 2,855	$ 2,251	$ 741
Sales and marketing	$ 24,176	$ 16,391	$ 4,003
General and administrative	$ 45,135	$ 40,897	$ 15,914
Research and development	$ 14,203	$ 6,023	$ 269

19. Income Taxes

The Company accounts for income taxes using the asset and liability method. Under this method, deferred income tax assets and liabilities are determined based upon the difference between the consolidated financial statement carrying amounts and the tax basis of assets and liabilities and are measured using the enacted tax rate expected to apply to taxable income in the years in which the differences are expected to be reversed.

The following table presents domestic and foreign components of (loss) income before income taxes for the periods presented (in thousands):

	Year Ended December 31,		
	2015	2014	2013
United States	$(1,467,184)	$ (718,416)	$ (272,603)
Noncontrolling interest and redeemable noncontrolling interests	710,492	319,196	95,968
Foreign	(8,804)	(2,746)	78
Total	$ (765,496)	$ (401,966)	$ (176,557)

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Notes to Consolidated Financial Statements (continued)

The income tax provision (benefit) is composed of the following (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Current:			
Federal	$ 2,946	$ 10	$ 10
State	812	473	80
Foreign	95	100	26
Total current provision	3,853	583	116
Deferred:			
Federal	13	(26,528)	(22,691)
State	3	(791)	(2,224)
Foreign	(543)	—	—
Total deferred provision	(527)	(27,319)	(24,915)
Total provision (benefit) for income taxes	$ 3,326	$ (26,736)	$ (24,799)

The following table presents a reconciliation of the federal statutory rate and the Company's effective tax rate for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Tax benefit at federal statutory rate	(35.00)%	(34.00)%	(34.00)%
State income taxes (net of federal benefit)	(5.66)	(1.71)	(0.88)
Foreign income and withholding taxes	(0.04)	0.44	1.41
Noncontrolling interests and redeemable noncontrolling interests adjustment	27.99	5.18	(16.62)
Investment in certain financing funds	(0.45)	16.49	36.20
Stock-based compensation	0.89	2.35	1.77
Prepaid tax expense	(19.38)	(5.45)	(1.39)
Other	0.03	1.24	(3.74)
Tax credits	(1.65)	(1.49)	(1.75)
Change in valuation allowance	33.70	10.30	4.96
Effective tax rate	0.43%	(6.65)%	(14.04)%

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Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The following table presents significant components of the Company's deferred tax assets and liabilities for the periods presented (in thousands):

	As of December 31,	
	2015	2014
Deferred tax assets:		
Accruals and reserves	$ 156,225	$ 29,142
Net operating losses	23,869	86,322
Accelerated gain on assets	26,005	25,710
Investment in certain financing funds	485,159	288,556
Tax rebate revenue	43,037	41,710
Stock-based compensation	47,605	21,769
Other deferred tax assets	9,887	5,507
Tax credits	7,946	10,849
Gross deferred tax assets	799,733	509,565
Valuation allowance	(369,157)	(111,222)
Net deferred tax assets	430,576	398,343
Deferred tax liabilities:		
Depreciation and amortization	(279,492)	(239,170)
Investment in certain financing funds	—	(86,518)
Initial direct costs related to customer solar energy system lease acquisition costs and Other deferred tax liabilities	(152,457)	(72,700)
Gross deferred tax liabilities	(431,949)	(398,388)
Net deferred taxes	$ (1,373)	$ (45)

An analysis of current and noncurrent deferred tax assets and liabilities is as follows (in thousands):

	As of December 31,	
	2015	2014
Current:		
Deferred tax assets	$ —	$ 17,381
Less: valuation allowance	—	(4,232)
Net current deferred tax assets	$ —	$ 13,149
Noncurrent:		
Deferred tax assets	$ 367,784	$ 488,043
Deferred tax liabilities	—	(394,247)
Total noncurrent gross deferred tax assets	367,784	93,796
Less: valuation allowance	(369,157)	(106,990)
Net noncurrent deferred tax liabilities	$ (1,373)	$ (13,194)

As of December 31, 2015 and 2014, the Company had federal net operating loss, or NOL, carryforwards of $29.5 million and $439.8 million, respectively. The NOL carryforwards expire at various dates beginning in 2028 if not utilized. In addition, the Company had NOLs for California income tax purposes of $27.9 million and $228.4 million as of December 31, 2015 and 2014, respectively, which expire at various dates beginning in 2028 if not utilized. The Company also had NOLs for other state income tax purposes of $235.5 million and $77.7 million, as of December 31, 2015 and 2014, respectively, which expire at various dates beginning in 2016 if not utilized. Included in the other state NOL carryovers above, $155.7 million relates to stock option windfall deductions that, when realized, will be credited to equity.

As of December 31, 2015 and 2014, the Company had investment tax credit carryforwards of $0.0 and $6.6 million and federal research and development tax credit carryforwards of $11.1 million and $0.6 million, respectively. The federal

research and development tax credit carryforward begins to expire in 2026 if not utilized. As of December 31, 2015 and 2014, the Company had

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

California research and development tax credit carryforwards of $8.7 million and $1.6 million, respectively. California research and development tax credit carryforwards can be carried forward indefinitely. As of December 31, 2015 and 2014, the Company had federal minimum tax credit carryforwards of $19.0 million and $0.3 million, respectively, which can be carried forward indefinitely. As of December 31, 2015 and 2014, the Company had California minimum tax credit carryforwards of $3.5 million and $0.2 million, respectively, which can be carried forward indefinitely. As of December 31, 2015 and 2014, the Company had foreign tax credit carryforwards of $2.2 million and $2.2 million, respectively, which begin to expire in 2023 if not utilized. When realized the majority of these carryforwards will be credited to equity.

The Company's recognition of deferred tax liabilities from the Silevo acquisition in September 2014 triggered the release of $27.3 million of deferred tax asset valuation allowances, which was accounted for outside of the purchase accounting for Silevo and was recognized as a benefit of income taxes in 2014.

The deferred tax liabilities supporting the realizability of the deferred tax assets in the above acquisitions will reverse in the same periods, are in the same jurisdiction and are of the same character as the temporary differences that gave rise to these deferred tax assets.

The Company's valuation allowance increased by $257.9 million during the year ended December 31, 2015 and increased by $51.3 million during the year ended December 31, 2014. The increase in the valuation allowance was primarily related to the Company's investment in the financing funds. The valuation allowance is determined in accordance with the provisions of ASC 740, *Income Taxes*, which requires an assessment of both negative and positive evidence when measuring the need for a valuation allowance. Based on the available objective evidence and the Company's history of losses, the Company believes it is more likely than not that the net deferred tax assets will not be realized. As of December 31, 2015 and 2014, the Company has applied a valuation allowance against its deferred tax assets net of the expected income from the reversal of its deferred tax liabilities.

In the current year, the Company utilized all available NOL carryforwards from prior years. The utilization of the remaining NOL carryforwards and credits may be subject to a substantial annual limitation due to the ownership change limitations provided by the IRC Section 382 and similar state provisions. The annual limitation may result in the expiration of NOL carryforwards and credits before utilization. The Company completed an IRC Section 382 analysis through December 31, 2015. Based on the analysis, the NOL carryforwards presented have accounted for any limited and potential lost attributes due to any ownership changes and expiration dates. The Company also analyzed the NOL carryovers related to our acquisitions of Zep Solar and Silevo. Based on the analysis, there were no significant limitations to the utilization of either Zep Solar's or Silevo's NOL carryforwards. The NOL carryforwards presented are not expected to expire unutilized.

As part of its asset monetization strategy, the Company has agreements to sell solar energy systems to joint venture funds. The gain on the sale of the assets has been eliminated in the consolidated financial statements. These transactions are treated as inter-company sales, and as such, income taxes are not recognized on the sales until the Company no longer benefits from the underlying assets. Since the assets remain within the consolidated group, the income tax expense incurred related to the sales is being deferred and amortized over the estimated useful life of the assets, which has been estimated to be 30 years. The deferral of income tax expense results in the recording of a prepaid tax expense that is included in the consolidated balance sheets as other assets. In 2015, the Company's tax profitability resulted in the utilization of the available net operating loss carryovers including net operating losses related to excess tax benefits from stock options. The utilization of excess tax benefits from stock options was recognized as an increase in additional paid in capital. The Company, pursuant to ASC 810, *Consolidation*, deferred the impact of both the current tax payable as well as the amount recorded in additional paid in capital on the consolidated balance sheet as an increase of the prepaid tax expense. As of December 31, 2015 and 2014, the Company had recorded an increase in prepaid tax expense of $105.8 million and $3.7 million, respectively, net of amortization. The amortization of the prepaid tax expense in each period makes up the major component of income tax expense.

As a result of the Company's acquisition of the noncontrolling interest in certain of its financing funds in second quarter of 2014, the Company accounted for the direct impacts of the acquisition as an adjustment to additional paid in capital, while the indirect impacts of the acquisition were accounted for in the consolidated statements of operations. Since

the Company owns 100% of these financing funds, they were treated as terminated for U.S. income tax purposes. Due to the deemed liquidation of these financing funds, no gain was recognized from the liquidating distributions of cash and assets. The Company also recognized a net deferred tax liability of $1.6 million resulting mainly from accelerated depreciation previously taken for tax purposes but not for book purposes. The impact of setting up this deferred tax liability was offset by a release of the valuation allowance, resulting in a net zero impact to the consolidated statements of operations.

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Notes to Consolidated Financial Statements (continued)

The Company had an immaterial amount of undistributed earnings of foreign subsidiaries as of December 31, 2015. Those earnings are considered to be indefinitely reinvested; accordingly, no provisions for federal or state income taxes have been provided thereon. Upon repatriation of those earnings, in the form of dividends or otherwise, the Company would be subject to both U.S. income taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable to the various foreign countries. Determination of the amount of unrecognized deferred U.S. income tax liability is not practicable due to the complexities associated with its hypothetical calculation. In addition, unrecognized foreign tax credit carryforwards would be available to reduce a portion of such U.S. tax liability. An immaterial amount of withholding taxes may be payable upon remittance of all previously unremitted earnings as of December 31, 2015.

Uncertain Tax Positions

The Company applies a two-step approach with respect to uncertain tax positions. This approach involves recognizing any uncertain tax positions that are more-likely-than-not of being ultimately realized and then measuring those positions to determine the amounts to be recognized. The Company has $10.1 million of unrecognized tax benefits as of December 31, 2015, and $5.0 million of the balance at December 31, 2015 would affect the Company's effective tax rate if recognized. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows (in thousands):

Balance, January 1, 2013	$ —
Acquired from Zep Solar	120
Balance, December 31, 2013	120
Acquired from Silevo	434
True-up to prior year ending balance	(23)
Balance, December 31, 2014	531
Additions related to positions from the current year	1,384
Additions related to positions from the prior years	8,181
Balance, December 31, 2015	$ 10,096

The interest and penalties for uncertain tax positions is presented in the consolidated statements of operations as income tax expense. There were no interest and penalties accrued for any uncertain tax positions as of December 31, 2015, 2014 and 2013.

The Company does not anticipate any significant changes either increase or decrease to the total amount of gross unrecognized benefits within the 12 months after December 31, 2015.

The Company is subject to taxation and files income tax returns in the U.S. and various state, local and foreign jurisdictions. The U.S. and state jurisdictions have statutes of limitations that generally range from three to five years. Due to the Company's net losses for years prior to 2015, substantially all of its federal, state, local and foreign income tax returns since inception are still subject to audit.

20. Defined Contribution Plan

In January 2007, the Company established a 401(k) plan, or the Retirement Plan, available to employees who meet the Retirement Plan's eligibility requirements. Participants may elect to contribute a percentage of their compensation to the Retirement Plan, up to a statutory limit. Participants are fully vested in their contributions. The Company may make discretionary contributions to the Retirement Plan as a percentage of participant contributions, subject to established limits. The Company did not make any contributions to the Retirement Plan during the years ended December 31, 2015, 2014 and 2013.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

21. Related Party Transactions

The Company's operations included the following related party transactions (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Revenue:			
Solar energy systems sales to related parties	$ 79	$ 2,479	$ 17
Expenditures:			
Purchases of inventories or equipment from related parties	$ 7,809	$ 3,383	$ 1,741
Fees paid or payable to related parties (included in sales and marketing expense)	$ —	$ 103	$ 81
Interest paid or payable to related parties (included in interest expense — net)	$ 2,125	$ 3	$ —

Related party balances were comprised of the following (in thousands):

	December 31, 2015	December 31, 2014
Due from related parties (included in accounts receivable)	$ 30	$ 30
Due to related parties (included in accounts payable)	$ 3,961	$ 300
Due to related parties (included in solar bonds)	$ 165,220	$ 530
Due to related parties (included in convertible senior notes)	$ 12,975	$ —
Due to related parties (included in accrued and other current liabilities)	$ 1,249	$ 3

The related party transactions were primarily purchases of batteries from Tesla Motors, Inc., or Tesla, issuances of Solar Bonds to SpaceX and the Company's Chief Technology Officer and issuances of convertible senior notes to an entity affiliated with the Chairman of the Company's board of directors and the Company's Chief Executive Officer. Tesla is considered a related party because the Chairman of the Company's board of directors is the Chief Executive Officer and Chairman of Tesla, other members of the Company's board of directors also serve as members of the board of directors of Tesla, the Company's Chief Financial Officer also serves as a member of the board of directors of Tesla and some members of the Company's board of directors and executive management are also investors in Tesla. SpaceX is considered a related party because the Chairman of the Company's board of directors is the Chief Executive Officer, Chief Designer, Chairman and a significant stockholder of SpaceX, other members of the Company's board of directors also serve as members of the board of directors of SpaceX and some members of the Company's board of directors and executive management are also investors in SpaceX.

22. Commitments and Contingencies

Noncancelable Leases

The Company leases offices, manufacturing and warehouse facilities, equipment, vehicles and solar energy systems under noncancelable leases. Aggregate rent expense for facilities and equipment for the years ended December 31, 2015, 2014 and 2013 was $41.1 million, $32.9 million and $13.8 million, respectively.

Future minimum lease payments under noncancelable leases as of December 31, 2015 are as follows (in thousands):

2016	$ 57,791
2017	53,277
2018	43,713

2019	30,573
2020	18,770
Thereafter	76,640
Total minimum lease payments	$ 280,764

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

Build-to-Suit Lease Arrangement

In September 2014, a subsidiary of the Company entered into a build-to-suit lease arrangement with the Research Foundation for the State University of New York, or the Foundation, for the construction of an approximately 1.0 million square-feet solar panel manufacturing facility with a capacity of 1.0 gigawatts on an approximately 88.2 acre site located in Buffalo, New York. Under the terms of the arrangement, which has been amended, the Foundation will construct the manufacturing facility and install certain utilities and other improvements, with participation by the Company as to the design and construction of the manufacturing facility, and acquire certain manufacturing equipment designated by the Company to be used in the manufacturing facility. The Foundation will cover (i) construction costs related to the manufacturing facility in an amount up to $350.0 million, (ii) the acquisition and commissioning of the manufacturing equipment in an amount up to $348.1 million and (iii) $51.9 million for additional specified scope costs, in cases (i) and (ii) only, subject to the maximum funding allocation from the State of New York, and the Company will be responsible for any construction and equipment costs in excess of such amounts. The Foundation will own the manufacturing facility and manufacturing equipment purchased by the Foundation. Following completion of the manufacturing facility, the Company will lease the manufacturing facility and the manufacturing equipment owned by the Foundation from the Foundation for an initial period of 10 years, with an option to renew, for $2 per year plus utilities.

Under the terms of the build-to-suit lease arrangement, the Company is required to achieve specific operational milestones during the initial term of the lease, which include employing a certain number of employees at the facility, within western New York and within the State of New York within specified time periods following the completion of the facility. The Company is also required to spend or incur approximately $5.0 billion in combined capital, operational expenses and other costs in the State of New York over the 10 years following the achievement of full production. On an annual basis during the initial lease term, as measured on each anniversary of the commissioning of the facility, if the Company fails to meet its specified investment and job creation obligations, then it would be obligated to pay a $41.2 million "program payment" to the Foundation for each year that it fails to meet these requirements. Furthermore, if the agreement is terminated due to a material breach by the Company, then additional amounts might be payable by the Company.

Due to the Company's involvement with the construction of the facility, its exposure to any potential cost overruns and its other commitments under the agreement, the Company is deemed to be the owner of the facility and the manufacturing equipment owned by the Foundation for accounting purposes during the construction phase. Accordingly, as of December 31, 2015 and 2014, the Company had recorded a non-cash build-to-suit lease asset under construction of $284.5 million and $26.5 million, respectively, and a corresponding build-to-suit lease liability on the consolidated balance sheets.

Indemnification and Guaranteed Returns

As disclosed in Notes 12 and 14, the Company is contractually committed to compensate certain fund investors for any losses that they may suffer in certain limited circumstances resulting from reductions in U.S. Treasury grants or ITCs. Generally, such obligations would arise as a result of reductions to the value of the underlying solar energy systems as assessed by the U.S. Treasury Department for purposes of claiming U.S. Treasury grants or as assessed by the IRS for purposes of claiming ITCs or U.S. Treasury grants. For each balance sheet date, the Company assesses and recognizes, when applicable, the potential exposure from this obligation based on all the information available at that time, including any guidelines issued by the U.S. Treasury Department on solar energy system valuations for purposes of claiming U.S. Treasury grants and any audits undertaken by the IRS. The Company believes that any payments to the fund investors in excess of the amount already recognized by the Company for this obligation are not probable based on the facts known at the reporting date.

The maximum potential future payments that the Company could have to make under this obligation would depend on the difference between the fair values of the solar energy systems sold or transferred to the funds as determined by the Company and the values that the U.S. Treasury Department would determine as fair value for the systems for purposes of claiming U.S. Treasury grants or the values the IRS would determine as the fair value for the systems for purposes of claiming ITCs or U.S. Treasury grants. The Company claims U.S. Treasury grants based on guidelines provided by the U.S. Treasury department and the statutory regulations from the IRS. The Company uses fair values determined with the

assistance of independent third-party appraisals commissioned by the Company as the basis for determining the ITCs that are passed-through to and claimed by the fund investors. Since the Company cannot determine future revisions to U.S. Treasury Department guidelines governing system values or how the IRS will evaluate system values used in claiming ITCs or U.S. Treasury grants, the Company is unable to reliably estimate the maximum potential future payments that it could have to make under this obligation as of each balance sheet date.

The Company is eligible to receive certain state and local incentives that are associated with renewable energy generation. The amount of incentives that can be claimed is based on the projected or actual solar energy system size and/or the amount of solar

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

energy produced. The Company also currently participates in one state's incentive program that is based on either the fair market value or the tax basis of solar energy systems placed in service. State and local incentives received are allocated between the Company and fund investors in accordance with the contractual provisions of each fund. The Company is not contractually obligated to indemnify any fund investor for any losses they may incur due to a shortfall in the amount of state or local incentives actually received.

As disclosed in Note 12, *VIE Arrangements*, the Company is contractually required to make payments to one fund investor to ensure that the fund investor achieves a specified minimum internal rate of return. The fund investor has already received a significant portion of the projected economic benefits from U.S. Treasury grant distributions and tax depreciation benefits. The contractual provisions of the fund state that the fund has an indefinite term unless the members agree to dissolve the fund. Based on the Company's current financial projections regarding the amount and timing of future distributions to the fund investor, the Company does not expect to make any payments as a result of this guarantee and has not accrued any liabilities for this guarantee. The amount of potential future payments under this guarantee is dependent on the amount and timing of future distributions to the fund investor and future tax benefits that accrue to the fund investor. Due to the uncertainties surrounding estimating the amounts of these factors, the Company is unable to estimate the maximum potential payments under this guarantee. To date, the fund investor has achieved the specified minimum internal rate of return as determined in accordance with the contractual provisions of the fund.

As disclosed in Note 16, *Lease Pass-Through Financing Obligation*, the lease pass-through financing funds have a one-time lease payment reset mechanism that occurs after the installation of all solar energy systems in a fund. As a result of this mechanism, the Company may be required to refund master lease prepayments previously received from investors. Any refunds of master lease prepayments would reduce the lease pass-through financing obligation.

Letters of Credit

As of December 31, 2015, the Company had $25.4 million of unused letters of credit outstanding, which carry a fee of 3.4% per annum.

Other Contingencies

In July 2012, the Company, along with other companies in the solar energy industry, received a subpoena from the U.S. Treasury Department's Office of the Inspector General to deliver certain documents in the Company's possession that were dated, created, revised or referred to after January 1, 2007 and that relate to the Company's applications for U.S. Treasury grants or communications with certain other solar energy development companies or with certain firms that appraise solar energy property for U.S Treasury grant application purposes. The Inspector General and the Civil Division of the U.S. Department of Justice are investigating the administration and implementation of the U.S Treasury grant program, including possible misrepresentations concerning the fair market value of the solar energy systems submitted by the Company in U.S. Treasury grant applications. If the Inspector General concludes that misrepresentations were made, the U.S. Department of Justice could decide to bring a civil action to recover amounts it believes were improperly paid to the Company. If the U.S. Department of Justice is successful in asserting this action, the Company could then be required to pay material damages and penalties for any funds received based on such misrepresentations, which, in turn, could require the Company to make indemnity payments to certain fund investors. The Company is unable to estimate the possible loss, if any, associated with this ongoing investigation.

On March 28, 2014, a purported stockholder class action was filed in the United States District Court for the Northern District of California against the Company and two of its officers. The complaint alleges claims for violations of the federal securities laws, and seeks unspecified compensatory damages and other relief on behalf of a purported class of purchasers of our securities from March 6, 2013 to March 18, 2014. On April 16, 2015, the District Court dismissed the complaint and allowed the plaintiffs to file an amended complaint in an attempt to remedy the defects in the original complaint. The plaintiffs filed their amended complaint, and the Company filed a renewed motion to dismiss on August 7, 2015. On January 5, 2016, the District Court dismissed the amended complaint and allowed the plaintiffs until February 15, 2016 to file a further amended complaint in an attempt to remedy the defects in the amended complaint. The Company believes that the claims are without merit and intends to defend itself vigorously. The Company is unable to estimate the possible loss, if any, associated with this lawsuit.

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

On June 5 and 11, 2014, stockholder derivative actions were filed in the Superior Court of California for the County of San Mateo, purportedly on behalf of the Company and against the board of directors, alleging that the board of directors breached its duties to the Company by failing to prevent the conduct alleged in the pending purported stockholder class action lawsuit. The Company and the individual board member defendants filed a motion to dismiss the complaint, which the Superior Court granted on December 17, 2015. The Superior Court allowed the plaintiffs until February 24, 2016 to file an amended complaint in an attempt to remedy the defects in the original complaint. The Superior Court scheduled a hearing on June 10, 2016 for any motion by the board of directors or the Company to dismiss the amended complaint. The Company will continue to review the claims asserted by the stockholders and is unable to estimate the possible loss, if any, associated with this lawsuit.

On September 18, 2015, a stockholder derivative action was filed in the Court of Chancery of the State of Delaware, purportedly on behalf of the Company and against the board of directors, alleging that the board of directors breached its duties to the Company by approving stock-based compensation to the non-employee directors that the plaintiff claims is excessive compared to the compensation paid to directors of peer companies. The Company is reviewing the claim and is unable to estimate the possible loss, if any, associated with this lawsuit.

On November 6, 2015, a putative class action was filed in the United States District Court for the Northern District of California against the Company. The complaint alleges that the Company made unlawful telephone marketing calls to the plaintiff and others, in violation of the federal Telephone Consumer Protection Act. The plaintiff seeks injunctive relief and statutory damages, on behalf of himself and a certified class. On January 25, 2016, the Company filed a motion to dismiss the complaint. The Company believes that the claims are without merit and intends to defend itself vigorously. The Company is unable to estimate the possible loss, if any, associated with this lawsuit.

From time to time, claims have been asserted, and may in the future be asserted, including claims from regulatory authorities related to labor practices and other matters. Such assertions arise in the normal course of the Company's operations. The resolution of any such assertions or claims cannot be predicted with certainty.

23. Basic and Diluted Net Loss Per Share

The following table sets forth the computation of the Company's basic and diluted net loss per share for the periods presented (in thousands, except share and per share amounts):

	Year Ended December 31,		
	2015	2014	2013
Net loss attributable to stockholders	$ (58,330)	$ (56,034)	$ (55,790)
Net loss attributable to common stockholders, basic	$ (58,330)	$ (56,034)	$ (55,790)
Net loss attributable to common stockholders, diluted	$ (58,330)	$ (56,034)	$ (55,790)
Weighted-average shares used to compute net loss per share attributable to common stockholders, basic	97,200,925	93,333,880	79,781,976
Weighted-average shares used to compute net loss per share attributable to common stockholders, diluted	97,200,925	93,333,880	79,781,976
Net loss per share attributable to common stockholders, basic	$ (0.60)	$ (0.60)	$ (0.70)
Net loss per share attributable to common stockholders, diluted	$ (0.60)	$ (0.60)	$ (0.70)

The following weighted-average outstanding shares of common stock equivalents were excluded from the computation of diluted net loss per share for the periods presented because including them would have been antidilutive:

	Year Ended December 31,		
	2015	2014	2013
Preferred stock warrants and common stock warrants	—	—	516,702
Common stock options	14,924,720	14,332,220	14,412,968
Restricted stock units	2,387,711	341,598	21,681
Convertible senior notes	10,740,484	5,434,673	735,740

SolarCity Corporation
Notes to Consolidated Financial Statements (continued)

24. Subsequent Events

New Debt Facilities

In January 2016, a subsidiary of the Company entered into agreements with a syndicate of banks for a five-year term loan with a total committed amount of $160.0 million. The term loan is secured by certain solar energy systems leased to customers.

On January 21, 2016, a subsidiary of the Company issued $185.0 million in aggregate principal of solar loan-backed notes with a final maturity date of September 2048. The solar loan-backed notes are secured by certain customer loans under MyPower.

Amendment to Silevo Acquisition Agreement

On February 2, 2016, the Silevo acquisition agreement was amended to reflect new product specifications and manufacturing process and to extend the deadline for achieving certain manufacturing-related milestones, which have been accounted for as contingent consideration. The contingent consideration balance as of December 31, 2015 reflects this amendment.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management is responsible for establishing and maintaining disclosure controls and procedures as defined in 13a-15(e) and 15d-15(e) under the Exchange Act. Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2015. The term "disclosure controls and procedures," as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2015, our Chief Executive Officer and Chief Financial Officer concluded that, as of such date, our disclosure controls and procedures were effective to provide reasonable assurance.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, our management used the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework (2013)*, or 2013 COSO framework. Based on our evaluation under the 2013 COSO framework, our management concluded that our internal control over financial reporting was effective.

Ernst & Young LLP, our independent registered public accounting firm, has issued a report on the effectiveness of our internal control over financial reporting, which is included herein.

As permitted by SEC regulations, our management's evaluation of internal control over financial reporting did not include an evaluation of the internal control activities of ILIOSSON, S.A. de C.V., which we acquired on August 7, 2015, is included in our December 31, 2015 consolidated financial statements, constituted $18.3 million or 0.3% of total assets as of December 31, 2015 and contributed a net loss of $1.6 million for the period from the acquisition date through December 31, 2015.

Changes in Internal Control Over Financial Reporting

There has been no change to our internal control over financial reporting during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Effectiveness of Internal Controls

Our management, including our principal executive officer and principal financial officer, do not expect that our disclosure controls or our internal control over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our organization have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people or by management override of

the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
SolarCity Corporation

We have audited SolarCity Corporation's (the Company) internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). SolarCity Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of ILIOSSON, S.A. de C.V., which is included in the 2015 consolidated financial statements of SolarCity Corporation and constituted $18.3 million and $8.0 million of total and net assets, respectively, as of December 31, 2015 and $1.1 million and $1.6 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of SolarCity Corporation also did not include an evaluation of the internal control over financial reporting of ILIOSSON, S.A. de C.V.

In our opinion, SolarCity Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2015 consolidated financial statements of SolarCity Corporation and our report dated February 10, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Los Angeles, California
February 10, 2016

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item 10 of Form 10-K that is found in our 2015 Proxy Statement to be filed with the SEC in connection with the solicitation of proxies for our 2016 Annual Meeting of Stockholders (2015 Proxy Statement) is incorporated by reference to our 2015 Proxy Statement. The 2015 Proxy Statement will be filed with the SEC within 120 days after the end of the fiscal year to which this report relates.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 of Form 10-K that is found in our 2015 Proxy Statement is incorporated by reference to our 2015 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 of Form 10-K that is found in our 2015 Proxy Statement is incorporated by reference to our 2015 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 of Form 10-K that is found in our 2015 Proxy Statement is incorporated by reference to our 2015 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item 14 of Form 10-K that is found in our 2015 Proxy Statement is incorporated by reference to our 2015 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Documents filed as part of this report are as follows:

1. Financial Statements

Our Consolidated Financial Statements are listed in the "Index to Consolidated Financial Statements" under Part II, Item 8 of this report.

2. Financial Statement Schedules

The required information is included elsewhere in this report, not applicable, or not material.

3. Exhibits

The exhibits listed in the accompanying "Index to Exhibits" are filed or incorporated by reference as part of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 10, 2016.

SOLARCITY CORPORATION

By: /s/ Lyndon R. Rive
Lyndon R. Rive
Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Lyndon R. Rive and Brad W. Buss, and each of them, as his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his substitutes, may lawfully do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Lyndon R. Rive Lyndon R. Rive	Founder, Chief Executive Officer and Director (Principal Executive Officer)	February 10, 2016
/s/ Brad W. Buss Brad W. Buss	Chief Financial Officer (Principal Accounting and Financial Officer)	February 10, 2016
/s/ Peter J. Rive Peter J. Rive	Founder, Chief Technology Officer and Director	February 10, 2016
/s/ Elon Musk Elon Musk	Chairman of the Board of Directors	February 10, 2016
/s/ John H. N. Fisher John H. N. Fisher	Director	February 10, 2016
/s/ Antonio J. Gracias Antonio J. Gracias	Director	February 10, 2016
/s/ Donald R. Kendall, Jr. Donald R. Kendall, Jr.	Director	February 10, 2016
/s/ Nancy E. Pfund Nancy E. Pfund	Director	February 10, 2016
/s/ Jeffrey B. Straubel Jeffrey B. Straubel	Director	February 10, 2016

EXHIBIT INDEX

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
2.1	Agreement and Plan of Merger, dated as of June 16, 2014, by and among SolarCity Corporation, Sunflower Acquisition Corporation, Sunflower Acquisition LLC, Silevo, Inc., Richard Lim, as Securityholder Representative, and U.S. Bank National Association, as Escrow Agent	8-K	001-35758	2.1	June 17, 2014
2.1a	Amendment No. 1 to Agreement and Plan of Merger, dated as of September 5, 2014, by and among SolarCity Corporation, Sunflower Acquisition Corporation, Sunflower Acquisition LLC, Silevo, Inc., Richard Lim, as Securityholder Representative, and U.S. Bank National Association, as Escrow Agent	10-Q	001-35758	2.1a	November 6, 2014
2.1b	Amendment No. 2 to Agreement and Plan of Merger, effective as of December 31, 2015, by and among SolarCity Corporation, Silevo, LLC, and Richard Lim, as Securityholder Representative				
2.2	Stock Purchase Agreement, dated August 3, 2015, by and among SolarCity Corporation, Solar Explorer, LLC, Solar Voyager, LLC, Tatiana Alejandra Arelle Caraveo, Manuel Vegara Llanes and ILIOSSON, S.A. de C.V.	8-K	001-35758	2.1	August 5, 2015
3.1	Amended and Restated Certificate of Incorporation of the Registrant	10-K	001-35758	3.1	March 27, 2013
3.2	Amended and Restated Bylaws of the Registrant	10-K	001-35758	3.2	March 27, 2013
4.1	Form of Common Stock Certificate of the Registrant	S-1/A	333-184317	4.1	November 27, 2012
4.2	Seventh Amended and Restated Investor's Rights Agreement by and among the Registrant and certain stockholders of the Registrant, dated February 24, 2012	S-1	333-184317	4.4	October 5, 2012
4.3	Indenture, dated as of October 21, 2013, by and between the Registrant and Wells Fargo Bank National Association, including the form of senior convertible notes contained therein	8-K	001-35758	4.1	October 21, 2013
4.4	Indenture, dated as of September 30, 2014, between the Registrant and Wells Fargo Bank, National Association	8-K	001-35758	4.1	October 6, 2014
4.5	Indenture, dated as of December 7, 2015, between the Registrant and Wells Fargo Bank, National Association	8-K	001-35758	4.1	December 7, 2015
4.6**	Indenture, dated as of January 9, 2015, by and between FTE Solar I, LLC and U.S. Bank National Association.	10-Q	001-35758	4.11	May 6, 2015
4.7	Indenture, dated as of October 15, 2014, between the Registrant and U.S. Bank National Association, as trustee.	S-3ASR	333-199321	4.1	October 15, 2014
4.8	First Supplemental Indenture, dated as of October 15, 2014, by and between the Company	8-K	001-35758	4.2	October 15, 2014

and the Trustee, related to the Company's 2.00%
Solar Bonds, Series 2014/1-1.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.9	Second Supplemental Indenture, dated as of October 15, 2014, by and between the Company and the Trustee, related to the Company's 2.50% Solar Bonds, Series 2014/2-2.	8-K	001-35758	4.3	October 15, 2014
4.10	Third Supplemental Indenture, dated as of October 15, 2014, by and between the Company and the Trustee, related to the Company's 3.00% Solar Bonds, Series 2014/3-3.	8-K	001-35758	4.4	October 15, 2014
4.11	Fourth Supplemental Indenture, dated as of October 15, 2014, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2014/4-7	8-K	001-35758	4.5	October 15, 2014
4.12	Fifth Supplemental Indenture, dated as of January 29, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/1-1.	8-K	001-35758	4.2	January 29, 2015
4.13	Sixth Supplemental Indenture, dated as of January 29, 2015, by and between the Company and the Trustee, related to the Company's 2.50% Solar Bonds, Series 2015/2-2.	8-K	001-35758	4.3	January 29, 2015
4.14	Seventh Supplemental Indenture, dated as of January 29, 2015, by and between the Company and the Trustee, related to the Company's 3.00% Solar Bonds, Series 2015/3-3.	8-K	001-35758	4.4	January 29, 2015
4.15	Eighth Supplemental Indenture, dated as of January 29, 2015, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2015/4-7.	8-K	001-35758	4.5	January 29, 2015
4.16	Ninth Supplemental Indenture, dated as of March 9, 2015, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2015/5-5.	8-K	001-35758	4.2	March 9, 2015
4.17	Tenth Supplemental Indenture, dated as of March 9, 2015, by and between the Company and the Trustee, related to the Company's 5.00% Solar Bonds, Series 2015/6-10.	8-K	001-35758	4.3	March 9, 2015
4.18	Eleventh Supplemental Indenture, dated as of March 9, 2015, by and between the Company and the Trustee, related to the Company's 5.75% Solar Bonds, Series 2015/7-15.	8-K	001-35758	4.4	March 9, 2015
4.19	Twelfth Supplemental Indenture, dated as of March 19, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C1-1.	8-K	001-35758	4.2	March 19, 2015
4.20	Thirteenth Supplemental Indenture, dated as of March 19, 2015, by and between the Company and the Trustee, related to the Company's 2.60% Solar Bonds, Series 2015/C2-3.	8-K	001-35758	4.3	March 19, 2015
4.21	Fourteenth Supplemental Indenture, dated as of March 19, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C3-5.	8-K	001-35758	4.4	March 19, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.22	Fifteenth Supplemental Indenture, dated as of March 19, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C4-10.	8-K	001-35758	4.5	March 19, 2015
4.23	Sixteenth Supplemental Indenture, dated as of March 19, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C5-15.	8-K	001-35758	4.6	March 19, 2015
4.24	Seventeenth Supplemental Indenture, dated as of March 26, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C6-1.	8-K	001-35758	4.2	March 26, 2015
4.25	Eighteenth Supplemental Indenture, dated as of March 26, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C7-3.	8-K	001-35758	4.3	March 26, 2015
4.26	Nineteenth Supplemental Indenture, dated as of March 26, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C8-5.	8-K	001-35758	4.4	March 26, 2015
4.27	Twentieth Supplemental Indenture, dated as of March 26, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C9-10.	8-K	001-35758	4.5	March 26, 2015
4.28	Twenty-First Supplemental Indenture, dated as of March 26, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C10-15.	8-K	001-35758	4.6	March 26, 2015
4.29	Twenty-Second Supplemental Indenture, dated as of March 30, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/8-1.	8-K	001-35758	4.2	March 30, 2015
4.30	Twenty-Third Supplemental Indenture, dated as of April 2, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C11-1.	8-K	001-35758	4.2	April 2, 2015
4.31	Twenty-Fourth Supplemental Indenture, dated as of April 2, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C12-3.	8-K	001-35758	4.3	April 2, 2015
4.32	Twenty-Fifth Supplemental Indenture, dated as of April 2, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C13-5.	8-K	001-35758	4.4	April 2, 2015
4.33	Twenty-Sixth Supplemental Indenture, dated as of April 2, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C14-10.	8-K	001-35758	4.5	April 2, 2015
4.34	Twenty-Seventh Supplemental Indenture, dated as of April 9, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C16-1.	8-K	001-35758	4.2	April 9, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.35	Twenty-Eighth Supplemental Indenture, dated as of April 9, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C17-3.	8-K	001-35758	4.3	April 9, 2015
4.36	Twenty-Ninth Supplemental Indenture, dated as of April 9, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C18-5.	8-K	001-35758	4.4	April 9, 2015
4.37	Thirtieth Supplemental Indenture, dated as of April 9, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C19-10.	8-K	001-35758	4.5	April 9, 2015
4.38	Thirty-First Supplemental Indenture, dated as of April 9, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C20-15.	8-K	001-35758	4.6	April 9, 2015
4.39	Thirty-Second Supplemental Indenture, dated as of April 14, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C21-1.	8-K	001-35758	4.2	April 14, 2015
4.40	Thirty-Third Supplemental Indenture, dated as of April 14, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C22-3.	8-K	001-35758	4.3	April 14, 2015
4.41	Thirty-Fourth Supplemental Indenture, dated as of April 14, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C23-5.	8-K	001-35758	4.4	April 14, 2015
4.42	Thirty-Fifth Supplemental Indenture, dated as of April 14, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C24-10.	8-K	001-35758	4.5	April 14, 2015
4.43	Thirty-Sixth Supplemental Indenture, dated as of April 14, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C25-15.	8-K	001-35758	4.6	April 14, 2015
4.44	Thirty-Seventh Supplemental Indenture, dated as of April 21, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C26-1.	8-K	001-35758	4.2	April 21, 2015
4.45	Thirty-Eighth Supplemental Indenture, dated as of April 21, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C27-10.	8-K	001-35758	4.3	April 21, 2015
4.46	Thirty-Ninth Supplemental Indenture, dated as of April 21, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C28-15.	8-K	001-35758	4.4	April 21, 2015
4.47	Fortieth Supplemental Indenture, dated as of April 27, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C29-1.	8-K	001-35758	4.2	April 27, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.48	Forty-First Supplemental Indenture, dated as of April 27, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C30-3.	8-K	001-35758	4.3	April 27, 2015
4.49	Forty-Second Supplemental Indenture, dated as of April 27, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C31-5.	8-K	001-35758	4.4	April 27, 2015
4.50	Forty-Third Supplemental Indenture, dated as of April 27, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C32-10.	8-K	001-35758	4.5	April 27, 2015
4.51	Forty-Fourth Supplemental Indenture, dated as of April 27, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C33-15.	8-K	001-35758	4.6	April 27, 2015
4.52	Forty-Fifth Supplemental Indenture, dated as of May 1, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/9-1.	8-K	001-35758	4.2	May 1, 2015
4.53	Forty-Sixth Supplemental Indenture, dated as of May 1, 2015, by and between the Company and the Trustee, related to the Company's 3.00% Solar Bonds, Series 2015/10-3.	8-K	001-35758	4.3	May 1, 2015
4.54	Forty-Seventh Supplemental Indenture, dated as of May 1, 2015, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2015/11-5.	8-K	001-35758	4.4	May 1, 2015
4.55	Forty-Eighth Supplemental Indenture, dated as of May 1, 2015, by and between the Company and the Trustee, related to the Company's 5.00% Solar Bonds, Series 2015/12-10.	8-K	001-35758	4.5	May 1, 2015
4.56	Forty-Ninth Supplemental Indenture, dated as of May 1, 2015, by and between the Company and the Trustee, related to the Company's 5.75% Solar Bonds, Series 2015/13-15.	8-K	001-35758	4.6	May 1, 2015
4.57	Fiftieth Supplemental Indenture, dated as of May 11, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C34-3.	8-K	001-35758	4.2	May 11, 2015
4.58	Fifty-First Supplemental Indenture, dated as of May 11, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C35-5.	8-K	001-35758	4.3	May 11, 2015
4.59	Fifty-Second Supplemental Indenture, dated as of May 11, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C36-10.	8-K	001-35758	4.4	May 11, 2015
4.60	Fifty-Third Supplemental Indenture, dated as of May 11, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C37-15.	8-K	001-35758	4.5	May 11, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.61	Fifty-Fourth Supplemental Indenture, dated as of May 14, 2015, by and between the Company and the Trustee, related to the Company's 2.50% Solar Bonds, Series 2015/14-2.	8-K	001-35758	4.2	May 14, 2015
4.62	Fifty-Fifth Supplemental Indenture, dated as of May 18, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C38-3.	8-K	001-35758	4.2	May 18, 2015
4.63	Fifty-Sixth Supplemental Indenture, dated as of May 18, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C39-5.	8-K	001-35758	4.3	May 18, 2015
4.64	Fifty-Seventh Supplemental Indenture, dated as of May 18, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C40-10.	8-K	001-35758	4.4	May 18, 2015
4.65	Fifty-Eighth Supplemental Indenture, dated as of May 18, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C41-15.	8-K	001-35758	4.5	May 18, 2015
4.66	Fifty-Ninth Supplemental Indenture, dated as of May 26, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C42-3.	8-K	001-35758	4.2	May 26, 2015
4.67	Sixtieth Supplemental Indenture, dated as of May 26, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C43-5.	8-K	001-35758	4.3	May 26, 2015
4.68	Sixty-First Supplemental Indenture, dated as of May 26, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C44-10.	8-K	001-35758	4.4	May 26, 2015
4.69	Sixty-Second Supplemental Indenture, dated as of May 26, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C45-15.	8-K	001-35758	4.5	May 26, 2015
4.70	Sixty-Third Supplemental Indenture, dated as of May 26, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/15-1.	8-K	001-35758	4.2	May 26, 2015
4.71	Sixty-Fourth Supplemental Indenture, dated as of June 8, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C46-3.	8-K	001-35758	4.2	June 10, 2015
4.72	Sixty-Fifth Supplemental Indenture, dated as of June 8, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C47-5.	8-K	001-35758	4.3	June 10, 2015
4.73	Sixty-Sixth Supplemental Indenture, dated as of June 8, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C48-10.	8-K	001-35758	4.4	June 10, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.74	Sixty-Seventh Supplemental Indenture, dated as of June 8, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C49-15.	8-K	001-35758	4.5	June 10, 2015
4.75	Sixty-Eighth Supplemental Indenture, dated as of June 16, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C50-3.	8-K	001-35758	4.2	June 16, 2015
4.76	Sixty-Ninth Supplemental Indenture, dated as of June 16, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C51-5.	8-K	001-35758	4.3	June 16, 2015
4.77	Seventieth Supplemental Indenture, dated as of June 16, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C52-10.	8-K	001-35758	4.4	June 16, 2015
4.78	Seventy-First Supplemental Indenture, dated as of June 16, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C53-15.	8-K	001-35758	4.5	June 16, 2015
4.79	Seventy-Second Supplemental Indenture, dated as of June 22, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C54-3.	8-K	001-35758	4.2	June 23, 2015
4.80	Seventy-Third Supplemental Indenture, dated as of June 22, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C55-5.	8-K	001-35758	4.3	June 23, 2015
4.81	Seventy-Fourth Supplemental Indenture, dated as of June 22, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C56-10.	8-K	001-35758	4.4	June 23, 2015
4.82	Seventy-Fifth Supplemental Indenture, dated as of June 22, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C57-15.	8-K	001-35758	4.5	June 23, 2015
4.83	Seventy-Sixth Supplemental Indenture, dated as of June 26, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/16-1.	8-K	001-35758	4.2	June 26, 2015
4.84	Seventy-Seventh Supplemental Indenture, dated as of June 29, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C58-1.	8-K	001-35758	4.2	June 29, 2015
4.85	Seventy-Eighth Supplemental Indenture, dated as of June 29, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C59-3.	8-K	001-35758	4.3	June 29, 2015
4.86	Seventy-Ninth Supplemental Indenture, dated as of June 29, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C60-5.	8-K	001-35758	4.4	June 29, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.87	Eightieth Supplemental Indenture, dated as of June 29, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C61-10.	8-K	001-35758	4.5	June 29, 2015
4.88	Eighty-First Supplemental Indenture, dated as of June 29, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C62-15.	8-K	001-35758	4.6	June 29, 2015
4.89	Eighty-Second Supplemental Indenture, dated as of July 14, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C63-1.	8-K	001-35758	4.2	July 14, 2015
4.90	Eighty-Third Supplemental Indenture, dated as of July 14, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C64-3.	8-K	001-35758	4.3	July 14, 2015
4.91	Eighty-Fourth Supplemental Indenture, dated as of July 14, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C65-5.	8-K	001-35758	4.4	July 14, 2015
4.92	Eighty-Fifth Supplemental Indenture, dated as of July 14, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C66-10.	8-K	001-35758	4.5	July 14, 2015
4.93	Eighty-Sixth Supplemental Indenture, dated as of July 14, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C67-15.	8-K	001-35758	4.6	July 14, 2015
4.94	Eighty-Seventh Supplemental Indenture, dated as of July 20, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C68-1.	8-K	001-35758	4.2	July 21, 2015
4.95	Eighty-Eighth Supplemental Indenture, dated as of July 20, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C69-3.	8-K	001-35758	4.3	July 21, 2015
4.96	Eighty-Ninth Supplemental Indenture, dated as of July 20, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C70-5.	8-K	001-35758	4.4	July 21, 2015
4.97	Ninetieth Supplemental Indenture, dated as of July 20, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C71-10.	8-K	001-35758	4.5	July 21, 2015
4.98	Ninety-First Supplemental Indenture, dated as of July 20, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C72-15.	8-K	001-35758	4.6	July 21, 2015
4.99	Ninety-Second Supplemental Indenture, dated as of July 31, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/17-1.	8-K	001-35758	4.2	July 31, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.100	Ninety-Third Supplemental Indenture, dated as of July 31, 2015, by and between the Company and the Trustee, related to the Company's 3.00% Solar Bonds, Series 2015/18-3.	8-K	001-35758	4.3	July 31, 2015
4.101	Ninety-Fourth Supplemental Indenture, dated as of July 31, 2015, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2015/19-5.	8-K	001-35758	4.4	July 31, 2015
4.102	Ninety-Fifth Supplemental Indenture, dated as of July 31, 2015, by and between the Company and the Trustee, related to the Company's 5.00% Solar Bonds, Series 2015/20-10.	8-K	001-35758	4.5	July 31, 2015
4.103	Ninety-Sixth Supplemental Indenture, dated as of July 31, 2015, by and between the Company and the Trustee, related to the Company's 5.75% Solar Bonds, Series 2015/21-15.	8-K	001-35758	4.6	July 31, 2015
4.104	Ninety-Seventh Supplemental Indenture, dated as of August 3, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C73-1.	8-K	001-35758	4.2	August 3, 2015
4.105	Ninety-Eighth Supplemental Indenture, dated as of August 3, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C74-3.	8-K	001-35758	4.3	August 3, 2015
4.106	Ninety-Ninth Supplemental Indenture, dated as of August 3, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C75-5.	8-K	001-35758	4.4	August 3, 2015
4.107	One Hundredth Supplemental Indenture, dated as of August 3, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C76-10.	8-K	001-35758	4.5	August 3, 2015
4.108	One Hundred-and-First Supplemental Indenture, dated as of August 3, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C77-15.	8-K	001-35758	4.6	August 3, 2015
4.109	One Hundred-and-Second Supplemental Indenture, dated as of August 10, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C78-1.	8-K	001-35758	4.2	August 10, 2015
4.100	One Hundred-and-Third Supplemental Indenture, dated as of August 10, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C79-3.	8-K	001-35758	4.3	August 10, 2015
4.111	One Hundred-and-Fourth Supplemental Indenture, dated as of August 10, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C80-5.	8-K	001-35758	4.4	August 10, 2015
4.112	One Hundred-and-Fifth Supplemental Indenture, dated as of August 10, 2015, by and between the	8-K	001-35758	4.5	August 10, 2015

Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C81-10.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.113	One Hundred-and-Sixth Supplemental Indenture, dated as of August 10, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C82-15.	8-K	001-35758	4.6	August 10, 2015
4.114	One Hundred-and-Seventh Supplemental Indenture, dated as of August 17, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C83-1.	8-K	001-35758	4.2	August 17, 2015
4.115	One Hundred-and-Eighth Supplemental Indenture, dated as of August 17, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C84-3.	8-K	001-35758	4.3	August 17, 2015
4.116	One Hundred-and-Ninth Supplemental Indenture, dated as of August 17, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C85-5.	8-K	001-35758	4.4	August 17, 2015
4.117	One Hundred-and-Tenth Supplemental Indenture, dated as of August 17, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C86-10.	8-K	001-35758	4.5	August 17, 2015
4.118	One Hundred-and-Eleventh Supplemental Indenture, dated as of August 17, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C87-15.	8-K	001-35758	4.6	August 17, 2015
4.119	One Hundred-and-Twelfth Supplemental Indenture, dated as of August 24, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C88-1.	8-K	001-35758	4.2	August 24, 2015
4.120	One Hundred-and-Thirteenth Supplemental Indenture, dated as of August 24, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C89-3.	8-K	001-35758	4.3	August 24, 2015
4.121	One Hundred-and-Fourteenth Supplemental Indenture, dated as of August 24, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C90-5.	8-K	001-35758	4.4	August 24, 2015
4.122	One Hundred-and-Fifteenth Supplemental Indenture, dated as of August 24, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C91-10.	8-K	001-35758	4.5	August 24, 2015
4.123	One Hundred-and-Sixteenth Supplemental Indenture, dated as of August 24, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C92-15.	8-K	001-35758	4.6	August 24, 2015

4.124	One Hundred-and-Seventeenth Supplemental Indenture, dated as of August 31, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C93-1.	8-K	001-35758	4.2	August 31, 2015
4.125	One Hundred-and-Eighteenth Supplemental Indenture, dated as of August 31, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C94-3.	8-K	001-35758	4.3	August 31, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.126	One Hundred-and-Nineteenth Supplemental Indenture, dated as of August 31, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C95-5.	8-K	001-35758	4.4	August 31, 2015
4.127	One Hundred-and-Twentieth Supplemental Indenture, dated as of August 31, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C96-10.	8-K	001-35758	4.5	August 31, 2015
4.128	One Hundred-and-Twenty-First Supplemental Indenture, dated as of August 31, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C97-15.	8-K	001-35758	4.6	August 31, 2015
4.129	One Hundred-and-Twenty-Second Supplemental Indenture, dated as of September 11, 2015, by and between the Company and the Trustee, related to the Company's Solar Bonds, Series 2015/R1.	8-K	001-35758	4.2	September 11, 2015
4.130	One Hundred-and-Twenty-Third Supplemental Indenture, dated as of September 11, 2015, by and between the Company and the Trustee, related to the Company's Solar Bonds, Series 2015/R2.	8-K	001-35758	4.3	September 11, 2015
4.131	One Hundred-and-Twenty-Fourth Supplemental Indenture, dated as of September 11, 2015, by and between the Company and the Trustee, related to the Company's Solar Bonds, Series 2015/R3.	8-K	001-35758	4.4	September 11, 2015
4.132	One Hundred-and-Twenty-Fifth Supplemental Indenture, dated as of September 14, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C98-1.	8-K	001-35758	4.2	September 15, 2015
4.133	One Hundred-and-Twenty-Sixth Supplemental Indenture, dated as of September 14, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C99-3.	8-K	001-35758	4.3	September 15, 2015
4.134	One Hundred-and-Twenty-Seventh Supplemental Indenture, dated as of September 14, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C100-5.	8-K	001-35758	4.4	September 15, 2015
4.135	One Hundred-and-Twenty-Eighth Supplemental Indenture, dated as of September 14, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C101-10.	8-K	001-35758	4.5	September 15, 2015
4.136	One Hundred-and-Twenty-Ninth Supplemental Indenture, dated as of September 14, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C102-15.	8-K	001-35758	4.6	September 15, 2015

4.137	One Hundred-and-Thirtieth Supplemental Indenture, dated as of September 28, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C103-1.	8-K	001-35758	4.2	September 29, 2015
4.138	One Hundred-and-Thirty-First Supplemental Indenture, dated as of September 28, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C104-3.	8-K	001-35758	4.3	September 29, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.139	One Hundred-and-Thirty-Second Supplemental Indenture, dated as of September 28, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C105-5.	8-K	001-35758	4.4	September 29, 2015
4.140	One Hundred-and-Thirty-Third Supplemental Indenture, dated as of September 28, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C106-10.	8-K	001-35758	4.5	September 29, 2015
4.141	One Hundred-and-Thirty-Fourth Supplemental Indenture, dated as of September 28, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C107-15.	8-K	001-35758	4.6	September 29, 2015
4.142	One Hundred-and-Thirty-Fifth Supplemental Indenture, dated as of October 13, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C108-1.	8-K	001-35758	4.2	October 13, 2015
4.143	One Hundred-and-Thirty-Sixth Supplemental Indenture, dated as of October 13, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C109-3.	8-K	001-35758	4.3	October 13, 2015
4.144	One Hundred-and-Thirty-Seventh Supplemental Indenture, dated as of October 13, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C110-5.	8-K	001-35758	4.4	October 13, 2015
4.145	One Hundred-and-Thirty-Eighth Supplemental Indenture, dated as of October 13, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C111-10.	8-K	001-35758	4.5	October 13, 2015
4.146	One Hundred-and-Thirty-Ninth Supplemental Indenture, dated as of October 13, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C112-15.	8-K	001-35758	4.6	October 13, 2015
4.137	One Hundred-and-Fortieth Supplemental Indenture, dated as of October 30, 2015, by and between the Company and the Trustee, related to the Company's 2.00% Solar Bonds, Series 2015/22-1.	8-K	001-35758	4.2	October 30, 2015
4.148	One Hundred-and-Forty-First Supplemental Indenture, dated as of October 30, 2015, by and between the Company and the Trustee, related to the Company's 3.00% Solar Bonds, Series 2015/23-3.	8-K	001-35758	4.3	October 30, 2015
4.149	One Hundred-and-Forty-Second Supplemental Indenture, dated as of October 30, 2015, by and between the Company and the Trustee, related to the Company's 4.00% Solar Bonds, Series 2015/24-5.	8-K	001-35758	4.4	October 30, 2015

4.150	One Hundred-and-Forty-Third Supplemental Indenture, dated as of October 30, 2015, by and between the Company and the Trustee, related to the Company's 5.00% Solar Bonds, Series 2015/25-10.	8-K	001-35758	4.5	October 30, 2015
4.151	One Hundred-and-Forty-Fourth Supplemental Indenture, dated as of October 30, 2015, by and between the Company and the Trustee, related to the Company's 5.75% Solar Bonds, Series 2015/26-15.	8-K	001-35758	4.6	October 30, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.152	One Hundred-and-Forty-Fifth Supplemental Indenture, dated as of November 4, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C113-1.	8-K	001-35758	4.2	November 4, 2015
4.153	One Hundred-and-Forty-Sixth Supplemental Indenture, dated as of November 4, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C114-3.	8-K	001-35758	4.3	November 4, 2015
4.154	One Hundred-and-Forty-Seventh Supplemental Indenture, dated as of November 4, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C115-5.	8-K	001-35758	4.4	November 4, 2015
4.155	One Hundred-and-Forty-Eighth Supplemental Indenture, dated as of November 4, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C116-10.	8-K	001-35758	4.5	November 4, 2015
4.156	One Hundred-and-Forty-Ninth Supplemental Indenture, dated as of November 4, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C117-15.	8-K	001-35758	4.6	November 4, 2015
4.157	One Hundred-and-Fiftieth Supplemental Indenture, dated as of November 16, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C118-1.	8-K	001-35758	4.2	November 17, 2015
4.158	One Hundred-and-Fifty-First Supplemental Indenture, dated as of November 16, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C119-3.	8-K	001-35758	4.3	November 17, 2015
4.159	One Hundred-and-Fifty-Second Supplemental Indenture, dated as of November 16, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C120-5.	8-K	001-35758	4.4	November 17, 2015
4.160	One Hundred-and-Fifty-Third Supplemental Indenture, dated as of November 16, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C121-10.	8-K	001-35758	4.5	November 17, 2015
4.161	One Hundred-and-Fifty-Fourth Supplemental Indenture, dated as of November 16, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C122-15.	8-K	001-35758	4.6	November 17, 2015
4.162	One Hundred-and-Fifty-Fifth Supplemental Indenture, dated as of November 30, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C123-1.	8-K	001-35758	4.2	November 30, 2015

4.163	One Hundred-and-Fifty-Sixth Supplemental Indenture, dated as of November 30, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C124-3.	8-K	001-35758	4.3	November 30, 2015
4.164	One Hundred-and-Fifty-Seventh Supplemental Indenture, dated as of November 30, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C125-5.	8-K	001-35758	4.4	November 30, 2015

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
4.165	One Hundred-and-Fifty-Eighth Supplemental Indenture, dated as of November 30, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C126-10.	8-K	001-35758	4.5	November 30, 2015
4.166	One Hundred-and-Fifty-Ninth Supplemental Indenture, dated as of November 30, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C127-15.	8-K	001-35758	4.6	November 30, 2015
4.167	One Hundred-and-Sixtieth Supplemental Indenture, dated as of December 14, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C128-1.	8-K	001-35758	4.2	December 14, 2015
4.168	One Hundred-and-Sixty-First Supplemental Indenture, dated as of December 14, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C129-3.	8-K	001-35758	4.3	December 14, 2015
4.169	One Hundred-and-Sixty-Second Supplemental Indenture, dated as of December 14, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C130-5.	8-K	001-35758	4.4	December 14, 2015
4.160	One Hundred-and-Sixty-Third Supplemental Indenture, dated as of December 14, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C131-10.	8-K	001-35758	4.5	December 14, 2015
4.171	One Hundred-and-Sixty-Fourth Supplemental Indenture, dated as of December 14, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C132-15.	8-K	001-35758	4.6	December 14, 2015
4.172	One Hundred-and-Sixty-Fifth Supplemental Indenture, dated as of December 28, 2015, by and between the Company and the Trustee, related to the Company's 1.60% Solar Bonds, Series 2015/C133-1.	8-K	001-35758	4.2	December 28, 2015
4.173	One Hundred-and-Sixty-Sixth Supplemental Indenture, dated as of December 28, 2015, by and between the Company and the Trustee, related to the Company's 2.65% Solar Bonds, Series 2015/C134-3.	8-K	001-35758	4.3	December 28, 2015
4.174	One Hundred-and-Sixty-Seventh Supplemental Indenture, dated as of December 28, 2015, by and between the Company and the Trustee, related to the Company's 3.60% Solar Bonds, Series 2015/C135-5.	8-K	001-35758	4.4	December 28, 2015
4.175	One Hundred-and-Sixty-Eighth Supplemental Indenture, dated as of December 28, 2015, by and between the Company and the Trustee, related to the Company's 4.70% Solar Bonds, Series 2015/C136-10.	8-K	001-35758	4.5	December 28, 2015

4.176	One Hundred-and-Sixty-Ninth Supplemental Indenture, dated as of December 28, 2015, by and between the Company and the Trustee, related to the Company's 5.45% Solar Bonds, Series 2015/C137-15.	8-K	001-35758	4.6	December 28, 2015
10.1*	Form of Indemnification Agreement for directors and executive officers	S-1	333-184317	10.1	October 5, 2012
10.2*	2007 Stock Plan and form of agreements used thereunder	S-1	333-184317	10.2	October 5, 2012
10.3*	2012 Equity Incentive Plan and form of agreements used thereunder	S-1	333-184317	10.3	October 5, 2012

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
10.4*	2012 Employee Stock Purchase Plan and form of agreements used thereunder	S-1	333-184317	10.4	October 5, 2012
10.5	Office Lease Agreement, between Locon San Mateo, LLC and the Registrant, dated as of July 30, 2010	S-1	333-184317	10.5	October 5, 2012
10.5a	First Amendment to Lease, between Locon San Mateo, LLC and the Registrant, dated as of November 15, 2010	S-1	333-184317	10.5a	October 5, 2012
10.5b	Second Amendment to Lease, between Locon San Mateo, LLC and the Registrant, dated as of March 31, 2011	S-1	333-184317	10.5b	October 5, 2012
10.10e**	Amended and Restated Credit Agreement among the Registrant, Bank of America, N.A. and other banks and financial institutions party thereto, dated as of November 1, 2013	10-K/A	001-35758	10.10e	September 4, 2014
10.10f	First Amendment to the Amended and Restated Credit Agreement, dated as of June 27, 2014, by and among the Registrant, Bank of America, N.A. and other banks and financial institutions party thereto	10-Q	001-35758	10.10f	August 7, 2014
10.10g**	Second Amendment to the Amended and Restated Credit Agreement, dated as of July 11, 2014, by and among the Registrant, Bank of America, N.A. and other banks and financial institutions party thereto	10-Q	001-35758	10.10g	August 7, 2014
10.10h	Third Amendment to the Amended and Restated Credit Agreement, dated as of September 23, 2014, by and among SolarCity Corporation, a Delaware corporation, the Lenders party hereto and Bank of America, N.A., as administrative agent	10-Q	001-35758	10.10h	November 6, 2014
10.10i**	Fourth Amendment to the Amended and Restated Credit Agreement, dated as of October 10, 2014, by and among SolarCity Corporation, a Delaware corporation, the Lenders party hereto and Bank of America, N.A., as administrative agent	10-Q	001-35758	10.10i	November 6, 2014
10.10j**	Fifth Amendment to the Amended and Restated Credit Agreement, dated as of December 19, 2014, by and among SolarCity Corporation, a Delaware corporation, the Lenders party hereto and Bank of America, N.A., as administrative agent	10-K	001-35758	10.10j	February 24, 2015
10.10k**	Sixth Amendment to the Amended and Restated Credit Agreement, dated as of June 24, 2015, by and among SolarCity Corporation, a Delaware corporation, the Lenders party hereto and Bank of America, N.A., as administrative agent	10-Q	001-35758	10.10k	July 30, 2015
10.10l	Seventh Amendment to the Amended and Restated Credit Agreement, dated as of July 24, 2015, by and among SolarCity Corporation, a Delaware corporation, the Lenders party thereto and Bank of America, N.A., as administrative agent.	10-Q	001-35758	10.10l	October 30, 2015
10.10m					

Eighth Amendment to the Amended and Restated Credit Agreement, dated as of November 17, 2015, by and among SolarCity Corporation, a Delaware corporation, the Lenders party thereto and Bank of America, N.A., as administrative agent.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
10.10n	Ninth Amendment to the Amended and Restated Credit Agreement, dated as of December 14, 2015, by and among SolarCity Corporation, a Delaware corporation, the Lenders party thereto and Bank of America, N.A., as administrative agent.				
10.13*	Zep Solar, Inc. 2010 Equity Incentive Plan and form of agreements used thereunder	S-8	333-192996	4.5	December 20, 2013
10.14**	Loan Agreement among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of February 4, 2014	10-Q/A	001-35758	10.14	October 10, 2014
10.14a**	Upsizing Amendment and Acknowledgment among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of February 20, 2014	10-Q/A	001-35758	10.14a	October 10, 2014
10.14b**	Second Upsizing Amendment among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of March 20, 2014	10-Q	001-35758	10.14b	May 7, 2014
10.14c**	Third Amendment to Loan Agreement among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of May 23, 2014	10-Q	001-35758	10.14c	August 7, 2014
10.14d**	Fourth Amendment to Loan Agreement among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of August 19, 2014	10-Q	001-35758	10.14d	November 6, 2014
10.14e	Fifth Amendment to Loan Agreement among Hammerhead Solar, LLC (an indirect wholly owned subsidiary of the Registrant), Bank of America, N.A. and other banks and financial institutions party thereto, dated as of October 28, 2015				
10.15**	Loan Agreement, dated May 23, 2014, by and among AU Solar 2, LLC (an indirect wholly owned subsidiary of the Registrant), ING Capital LLC, CIT Finance LLC, Goldman Sachs Lending Partners LLC, Crédit Agricole Corporate and Investment Bank and the other banks and financial institutions party thereto	10-Q	001-35758	10.15	August 7, 2014
10.15a**	Amendment No. 1 to Loan Agreement, dated as of December 11, 2014, by and among AU Solar 2, LLC (an indirect wholly owned subsidiary of the Registrant), ING Capital LLC, CIT Finance LLC, Goldman Sachs Lending Partners LLC, Crédit Agricole Corporate and Investment Bank	10-K	001-35758	10.15a	February 24, 2015

	and the other banks and financial institutions party thereto				
10.16	Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of September 2, 2014, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, Inc.	10-Q	001-35758	10.16	November 6, 2014

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
10.16a	First Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of October 31, 2014, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, Inc.	10-K	001-35758	10.16a	February 24, 2015
10.16b	Second Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of December 15, 2014, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, Inc.	10-K	001-35758	10.16b	February 24, 2015
10.16c	Third Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of February 12, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, Inc.	10-Q	001-35758	10.16c	May 6, 2015
10.16d	Fourth Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of March 30, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, Inc.	10-Q	001-35758	10.16d	May 6, 2015
10.16e	Fifth Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of June 30, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, LLC.	10-Q	001-35758	10.16e	July 30, 2015
10.16f	Sixth Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of September 1, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, LLC.	10-Q	001-35758	10.16f	October 30, 2015
10.16g	Seventh Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of October 9, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, LLC.	10-Q	001-35758	10.16g	October 30, 2015
10.16h		10-Q	001-35758	10.16h	October 30, 2015

Eighth Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of October 26, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, LLC.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
10.16i	Ninth Amendment to Amended and Restated Agreement For Research & Development Alliance on Triex Module Technology, effective as of December 9, 2015, by and between The Research Foundation For The State University of New York, on behalf of the College of Nanoscale Science and Engineering of the State University of New York, and Silevo, LLC.				
10.17a**	Standard Definitions, Annex A to the Indenture, dated as of January 9, 2015, by and between FTE Solar I, LLC and U.S. Bank National Association.	10-Q	001-35758	10.17a	May 6, 2015
10.17b**	Note Purchase Agreement, dated January 9, 2015, by and among FTE Solar I, LLC, SolarCity Finance Company, LLC, SolarCity Corporation, Purchasers, the Funding Agents and Credit Suisse AG, New York Branch.	10-Q	001-35758	10.17b	May 6, 2015
10.18**	Credit Agreement, dated as of March 31, 2015, by and among Shortfin Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.18	May 6, 2015
10.19**	Loan Agreement, dated as of May 4, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19	July 30, 2015
10.19a**	Majority Group Agent Action No. 1, dated as of May 18, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19a	July 30, 2015
10.19b**	Required Group Agent Action No. 2, dated as of June 26, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19b	July 30, 2015
10.19c	Required Group Agent Action No. 3, dated as of July 13, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19c	October 30, 2015
10.19d	Required Group Agent Action No. 4, dated as of August 25, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as	10-Q	001-35758	10.19d	October 30, 2015

limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
10.19e**	Required Group Agent Action No. 5, dated as of August 27, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19e	October 30, 2015
10.19f**	Required Group Agent Action No. 7, dated as of September 30, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.	10-Q	001-35758	10.19f	October 30, 2015
10.19g**	Required Group Agent Action No. 8, dated as of October 23, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as administrative agent, and the group agents party thereto.				
10.19h	Required Group Agent Action No. 9, dated as of November 25, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the lenders party thereto.				
10.19i**	Required Group Agent Action No. 10, dated as of December 18, 2015, by and among Megalodon Solar, LLC (an indirect wholly owned subsidiary of the Registrant), as borrower, the Registrant, as limited guarantor, Bank of America, N.A., as collateral agent and administrative agent, and the group agents party thereto.				
10.20*	Description of Founder Awards	8-K	001-35758	N/A	August 27, 2015
21.1	List of Subsidiaries				
23.1	Consent of Independent Registered Public Accounting Firm				
24.1	Power of Attorney (contained in the signature page to this Annual Report on Form 10-K)				
31.1	Certification of the Chief Executive Officer pursuant to Section 302(a) of the Sarbanes-Oxley Act of 2002				
31.2	Certification of the Chief Financial Officer pursuant to Section 302(a) of the Sarbanes-Oxley Act of 2002				
32.1†	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002				
32.2†	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted				

	pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document.

Exhibit Number	Exhibit Description	Form	File No.	Incorporated by Reference	Exhibit Filing Date
101.SCH	XBRL Taxonomy Extension Schema Linkbase Document.				
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.				
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.				
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.				
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.				

* Indicates a management contract or compensatory plan or arrangement.

** Registrant has omitted portions of the relevant exhibit and filed such exhibit separately with the Securities and Exchange Commission pursuant to a request for confidential treatment under Rule 406 under the Securities Act of 1933, as amended.

† The certifications attached as Exhibit 32.1 and 32.2 that accompany this Annual Report on Form 10-K are not deemed filed with the Securities and Exchange Commission and are not to be incorporated by reference into any filing of SolarCity Corporation under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, whether made before or after the date of this Form 10-K, irrespective of any general incorporation language contained in such filing.

EXHIBIT
TASC 23
ADMITTED

aps

Kerri A. Carnes
Manager
State Regulation and Compliance

Mail Station 9712
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-3341
Kerri.Carnes@aps.com

March 9, 2016

Court Rich
The Alliance for Solar Choice
7144 E. Stetson Drive
Suite 300
Scottsdale, AZ 85251

RE: UNS Electric Rate Case
Docket No. E-04204A-15-0142

Attached please find Arizona Public Service Company's Response to TASC's Eighth Set of Data Requests in the above-referenced matter.

If you have any questions, please contact me at (602)250-3341.

Sincerely,

Stefan Layton (for Kerri Carnes)

Kerri A. Carnes

KC/ac
Attachment

cc: Hopi Slaughter

ARIZONA CORPORATION COMMISSION
TASC'S EIGHTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
MARCH 7, 2016

TASC 8.1: Please provide on a year by year basis, though the end of the study (2016-2035) period, the following assumptions/model inputs used in the report titled "The Economic Impact of Distributed Solar in the APS Service Territory, 2016-2035," attached to Mr. Brown's Surrebuttal and identified by you as "Attachment ACB-2SR":

a) The total participant net savings for each of the three distributed solar deployment scenarios and the break down by customer class.

b) The total non-participant ratepayer cost for each of the three distributed solar deployment scenarios:

a. Please provide in detail all underlying assumptions and calculations that lead to the estimated non-participant rate impact including: (1) the avoided utility costs from increased customer DG adoption (by as granular categorization as possible); (2) any assumed incremental utility expenditures associated with increased DG; and (3) the lost retail revenue from increased adoption by customer class segment on a per kw and per kwh basis.

c) The total customer cost of the systems under all three scenarios.

d) The portion of total spending, including detail regarding the project investment, install expenditures and wholesale spending, that stays in Arizona under all three scenarios.

e) Identify the main categories of economic impact by year.

Response: (a) There is no disaggregation between participant and non-participant customers in the study titled "The Economic Impact of Distributed Solar in the APS Service Territory, 2016-2035"

(b) There is no disaggregation between participant and non-participant customers in the study titled "The Economic Impact of Distributed Solar in the APS Service Territory, 2016-2035"

(c) Please see attachment APS15857 for the customer costs of installed distributed generation solar systems that were used for each of the three scenarios between 2016 and 2035.

Witness: Ashley Brown

Response to TASC 8.1 continued:

(d) Please see attachment APS15858 for categorical investment impacts in Arizona for each of the three scenarios between 2016 and 2035. The data describe the total spend for each category for each scenario and the associated regional purchase coefficients (RPCs) used in the study's modeling.

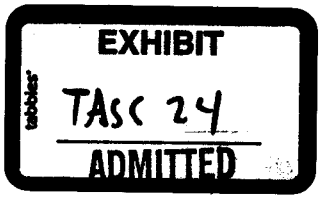
(e) Please see attachment APS15859 which describes impacts to Gross State Product, Private Non-Farm Employment, and Real Disposable Personal Income for each development scenario relative to the base case for both Arizona and Maricopa County.

Witness: Ashley Brown

Economic Activity Related to Distributed Rooftop Solar Investments Displacing Conventional Generation Investments
Annual Operating and Financing Costs to Consumers
(In Thousands of Nominal Dollars)

	LOW DE CASE			MEDIUM DE CASE			HIGH DE CASE		
	Annual Consumer Payments			Annual Consumer Payments			Annual Consumer Payments		
	DE Solar	Conventional Generation	Combined Total	DE Solar	Conventional Generation	Combined Total	DE Solar	Conventional Generation	Combined Total
2016	2,337	(544)	1,793	13,619	(2,959)	10,660	13,619	(2,959)	10,660
2017	5,656	(1,280)	4,376	34,035	(7,119)	26,917	46,560	(9,914)	36,646
2018	13,527	(3,271)	10,257	63,500	(45,271)	18,228	87,553	(49,663)	37,890
2019	16,326	(3,868)	12,458	97,501	(50,282)	47,219	132,758	(56,796)	75,961
2020	25,026	(6,355)	18,671	131,152	(57,773)	73,380	182,300	(67,672)	114,628
2021	38,632	(10,242)	28,390	164,426	(65,382)	99,044	236,726	(48,552)	188,173
2022	53,873	(20,129)	33,744	199,613	(90,948)	108,665	300,363	(121,157)	179,207
2023	70,098	(26,840)	43,258	233,883	(102,964)	130,919	377,781	(146,611)	231,170
2024	86,991	(68,924)	18,068	267,841	(117,702)	150,139	473,616	(217,048)	256,568
2025	104,683	(75,966)	28,717	304,944	(132,231)	172,713	589,102	(218,862)	370,240
2026	117,342	(81,473)	35,869	341,210	(183,526)	157,685	718,850	(299,113)	419,737
2027	124,740	(120,770)	3,970	375,571	(161,389)	214,182	852,238	(313,932)	538,306
2028	132,431	(123,429)	9,002	418,936	(182,960)	235,977	978,251	(364,108)	614,143
2029	140,367	(87,397)	52,970	480,169	(249,122)	231,047	1,089,523	(441,732)	647,791
2030	148,531	(90,937)	57,594	568,150	(290,338)	277,812	1,184,783	(481,340)	703,442
2031	156,954	(95,225)	61,729	682,652	(258,083)	424,569	1,267,325	(429,954)	837,371
2032	163,175	(98,184)	64,991	790,459	(347,972)	442,487	1,341,355	(508,439)	832,916
2033	168,313	(100,154)	68,159	862,434	(426,900)	435,534	1,395,954	(579,310)	816,644
2034	172,953	(101,571)	71,382	911,718	(409,097)	502,621	1,440,752	(560,015)	880,737
2035	177,391	(103,757)	73,634	948,432	(475,043)	473,388	1,480,931	(630,151)	850,780

Center for American Progress



Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class

By Mari Hernandez October 21, 2013

Homeowners across the United States have begun a rooftop solar revolution. Since 2000, more than 1,460 megawatts of residential solar installations have been installed across the country, and more than 80 percent of that capacity was added in the past four years.[1] In 2012 alone, rooftop solar installations reached 488 megawatts, a 62 percent increase over 2011 installations and nearly double the installed capacity added in 2010.[2]

Residential solar photovoltaic, or PV, systems—also referred to as "distributed" or "rooftop solar" in this report—consist of an array of solar panels that are roof or ground mounted to produce electricity that is either fed back into the electric grid—grid connected—or solely used onsite by the residential building—off grid.

The question is: Who is buying up all of those solar power systems? Through our analysis of solar installation data from Arizona, California, and New Jersey, we found that these installations are overwhelmingly occurring in middle-class neighborhoods that have median incomes ranging from $40,000 to $90,000. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both Arizona and California and $30,000 to $40,000 in New Jersey. Additionally, the distribution of solar installations in these states aligns closely with the population distribution across income levels.

But many within the electric utility industry have claimed that distributed solar is mainly being adopted by wealthy customers. Concerned by the threat that rooftop solar's rapid growth poses to traditional utility business models, some utility executives have used this claim to support a rising desire within the industry to alter existing solar programs and policies. The idea is that through solar policies such as net metering, middle- and low-income customers who cannot afford to go solar are subsidizing the wealthy customers who can.

In this issue brief, we show that rooftop solar is not just being adopted by the wealthy; it is, in fact, mostly being deployed in neighborhoods where median income ranges from $40,000 to $90,000. In the first section, we present the overall findings from our income analysis of solar installation data from Arizona, California, and New Jersey. We then discuss the implications of those results in the context of the current growth of rooftop solar and the ongoing discussion of solar policies that will affect its future growth.

Rooftop solar adoption trends

California, Arizona, and New Jersey are currently leading the nation in solar deployment and therefore offer insights into the way that rooftop solar is being adopted across the country. Although these states are home to varying solar programs and incentives, similarities exist in the way that residential solar installations occur across income levels, with our research showing that the majority of solar power systems are being installed in middle-class neighborhoods.

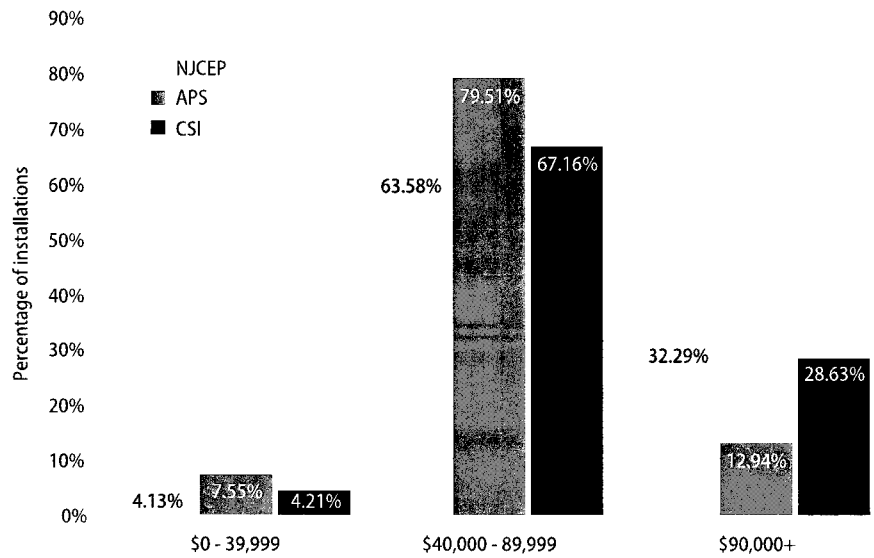
We collected solar installation data contained in the Arizona Public Service, or APS; the California Solar Initiative, or CSI; and New Jersey's Clean Energy Program, or NJCEP, databases to examine the adoption of rooftop solar by income level. These databases contain information on individual installations for which residential and nonresidential customers have applied for solar incentives, such as rebates or renewable energy certificates.

The APS database contains data on installations made under the solar rebate program offered by Arizona Public Service, which is the largest utility in Arizona and provides electric service to most of the state. The CSI database tracks installations made under the California Solar Initiative program, which offers rebates to customers of three investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric. The NJCEP database contains data on installations made under any of the following incentive programs offered in New Jersey: Solar Renewable Energy Certificates, the Renewable Energy Incentive Program, and the Customer On-site Renewable Energy Program.

By analyzing the median household income that corresponds with installations from each ZIP code in the three datasets, we found three key similarities. First, they all exhibit a similar installation distribution pattern, in that at least 60 percent of homeowners are installing solar panels in ZIP codes with median incomes ranging from $40,000 to $90,000. In fact, 80 percent of APS installations were for customers in that income range. To demonstrate this, Figure 1 shows the percentage of rooftop solar installations by dataset and income range.

FIGURE 1

Percentage of installations by dataset and income range



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

Another characteristic the datasets share is that the distributions of solar installations across income levels are similar to the population distributions within each region. Figure 2 displays the installation and population distributions across income levels for each dataset.

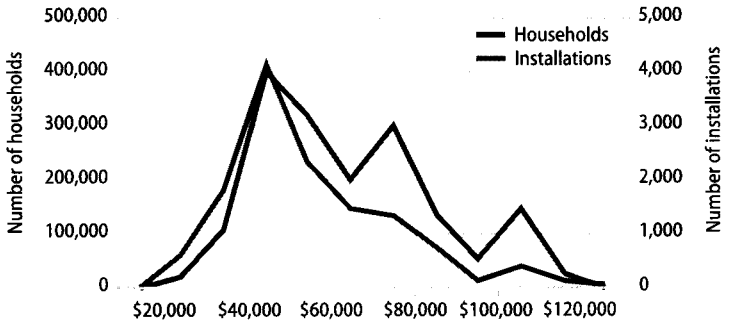
As you can see in Figure 2, the APS and CSI graphs show that installations and populations are more closely aligned in the lower income brackets of less than $60,000, while the NJCEP graph shows nearly perfect alignment in the higher income brackets of $90,000 and above. This alignment between solar installations and household distribution indicates that installations are being spread somewhat evenly over the population, especially in the lower income ranges in Arizona and California and in the higher income ranges in New Jersey. Out of all of the datasets, the distribution of CSI installations is the most skewed toward the upper income brackets.

The third similarity between the datasets is the growth of solar installations occurring in neighborhoods with median incomes ranging from $40,000 to $90,000 over the past several years. Figure 3 shows the share of installations by income range for each dataset from 2009 to the present.

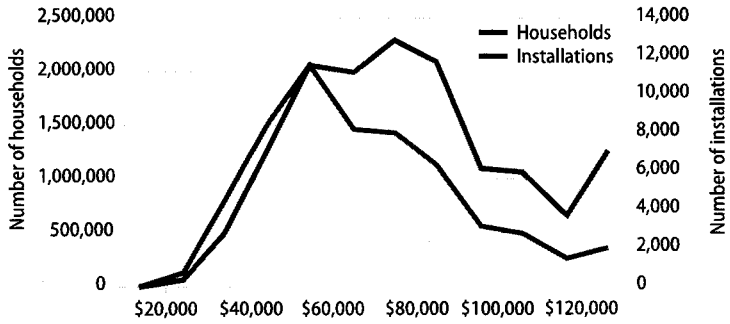
All three graphs in Figure 3 show a positive growth trend for the $40,000 to $90,000 income range, and so far, 2013 has continued that trend. Notably, the share of installations occurring in ZIP codes with median incomes of less than $40,000 increased in both the CSI and NJCEP datasets from 2011 to 2012.

FIGURE 2

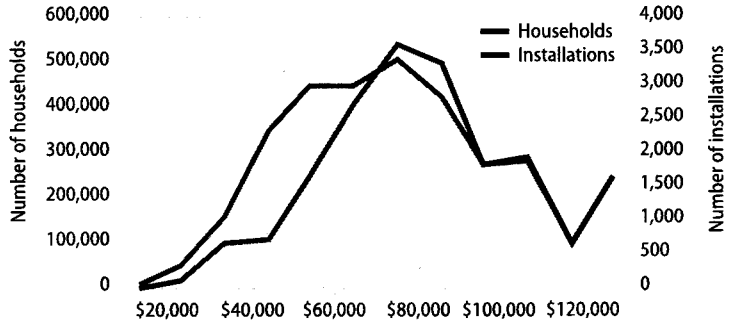
APS installations and households by income level



CSI installations and households by income level



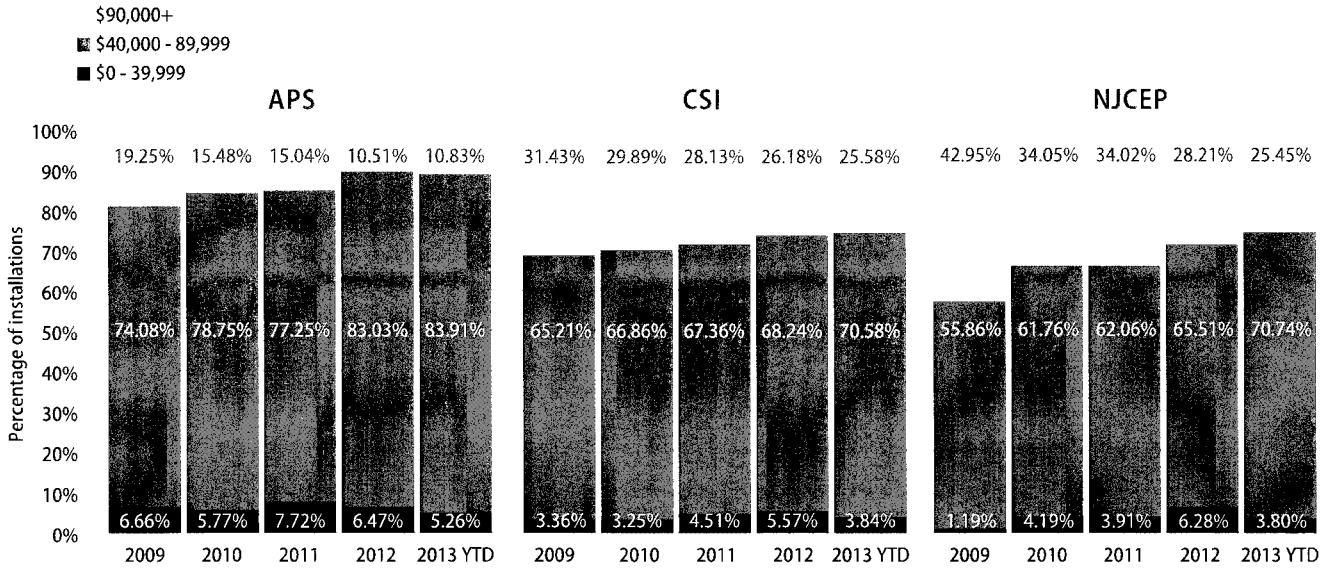
NJCEP installations and households by income level



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

FIGURE 3

APS, CSI, and NJCEP percentage of installations by income level and year



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013);"American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

Other key findings

Our analysis also provided other interesting results in the areas that have seen the highest number of cumulative installations and the fastest year-over-year growth from 2011 to 2012. In Arizona, the highest number of installations occurred in ZIP codes with median incomes ranging from $40,000 to $50,000. In California and New Jersey, homeowners who live in ZIP codes with median incomes ranging from $70,000 to $80,000 have installed the most solar power systems. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both Arizona and California and $30,000 to $40,000 in New Jersey.

Context and implications

Although rooftop solar currently makes up less than one-quarter of 1 percent of the electricity produced in the United States, utilities are beginning to see how solar could eventually affect their business models as it is rapidly adopted in their service territories. As homeowners install solar panels on their roofs, they reduce the amount of electricity they have to buy from their utility. Utilities, which generally include a portion of fixed costs in their energy-use charges, will then need to raise their electricity rates in order to maintain the electric grid and infrastructure, leading to what is known as the "utility death spiral." As rates increase, more utility customers will choose to go solar, and rates will continue to go up.

The death-spiral threat has caused many in the utility industry to examine their solar-related policies, and some utilities are now attempting to revise solar incentives and rate structures such as net metering.[3] Net metering, which allows solar customers to get credit for any excess energy they supply to the electric grid, is one of the most contentious topics right now in the utility industry; solar advocates are following it closely because of its importance to the growth of rooftop solar.

Many utility executives, in explaining their desire to alter existing solar policies, have said they are concerned that only wealthy customers are adopting rooftop solar, meaning that customers who cannot afford to go solar are subsidizing the rich through the utility's solar policies. At an annual meeting earlier this year, Southern Company CEO Thomas Fanning told shareholders that if solar customers are not paying the utility for the use of the electric grid, then "... you in effect have a de facto subsidy of rich people putting solar panels on their roof and having lower-income families subsidize them."[4] In recent comments filed with the Massachusetts Department of Energy Resources in response to the proposal for an expanded solar carve-out program, Ronald Gerwatowski, senior vice president of National Grid, wrote that, "Net metering operates much like a regressive tax, where the customers who cannot afford to install solar generation pay more to subsidize those customers who are able to afford an investment in solar."[5]

But solar technology, which has become more accessible in the past few years due to falling costs, as well as incentives and solar programs, is now being installed across different income levels, and it is especially popular among homeowners who live in ZIP codes with median incomes ranging from $40,000 to $90,000. While it is true that the wealthy are generally the first adopters of new technologies, our research suggests that solar technology has moved beyond the early adopter phenomenon and onto more widespread installation by the middle class.

The oft-repeated utility-industry narrative is not only being used as a vehicle for solar policy scrutiny—it also serves as a distraction from the fact that solar technology provides the same benefits to the grid regardless of the homeowner's income level. These benefits include avoided fuel costs, reduced transmission and distribution costs, emissions-free energy production, and generation capacity that can offset use during peak energy-consumption times during the day in certain regions. Some utilities have quantified those benefits and found that the value that solar technology brings to the grid in their service territory is actually higher than the retail electricity rate. Through a value-of-solar rate structure, for example, Austin, Texas-based municipal utility Austin Energy pays its solar customers 12.8 cents for every kilowatt hour[6] their systems generate, which is higher than the current retail rates, which range from 3.3 cents to 11.4 cents per kilowatt hour—depending on each customer's overall energy use[7]—and are based on a value-of-solar study done by Clean Power Research that is updated annually.[8]

Net metering and other solar policies encourage rooftop solar deployment and have made solar power generation a good deal for more than just the wealthy. It is important that these policies continue to be offered to accelerate the growth of rooftop solar in neighborhoods across the country.

The transition to a cleaner, lower-carbon electricity system is critical to our ability to meaningfully address climate change now and in the coming years. This transition will require the deployment of vast amounts of solar power systems, and the opportunity to put those systems on homes in every city is too great to pass up. As net metering and other solar policies are debated in different parts of the country, regulators and policymakers should consider the impacts that any changes will have on the affordability of solar technology for middle-class homeowners and how they will impact the future growth of rooftop solar.

Conclusion

Middle-class homeowners are leading the rooftop solar revolution. This finding will have far-reaching implications as utilities across the country consider revising their solar programs and rate structures, which benefit lower- and middle-class people—who are increasingly installing solar—and not just wealthier people.

Our research shows that most solar installations are occurring in middle-class neighborhoods, and that the fastest-growing areas for rooftop solar have median incomes ranging from $40,000 to $50,000 in Arizona and California and from $30,000 to $40,000 in New Jersey. Regulators and policymakers should consider how net metering and other solar policies support the growth of rooftop solar among middle-class homeowners and how they can continue to expand the use of a clean, renewable energy resource.

Data collection and methodology

To determine the income distribution of rooftop solar customers, we collected data from the APS, CSI, and NJCEP databases. APS is the largest electric utility in Arizona. It provides electric service to almost all of the state, excluding half of the Phoenix metropolitan area, the Tucson metropolitan area, and Mohave County in Northwestern Arizona. The APS database contains solar installation data for residential and non-residential customers who applied for solar incentives within the APS territory from January 2002 to the present.[9] The APS data were downloaded on August 8, 2013, and filtered for completed residential solar photovoltaics, or PV, system installations.

CSI is the solar rebate program offered to customers of three investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric. The CSI database contains solar installation data for residential and nonresidential customers who have applied for rebates under the CSI program from January 2007 to the present.[10] The CSI data were filtered for completed residential solar PV system installations. Our analysis was based on the August 7, 2013, version of the CSI database.

NJCEP promotes energy efficiency and the use of renewable energy sources in New Jersey. The NJCEP database contains solar installation data for residential and nonresidential customers who have registered for Solar Renewable Energy Certificates or received solar rebates through the Renewable Energy Incentive Program—which closed to new solar rebate applications in 2010—and the Customer On-site Renewable Energy Program, which closed to new applicants in 2008.[11] The NJCEP data were downloaded on September 5, 2013, and filtered for completed residential solar PV system installations.

Using information from the U.S. Census Bureau's 2011 American Community Survey, which gauged five-year estimates, we found the median household income for each ZIP code in which there was a residential solar installation accounted for in the APS, CSI, and NJCEP databases.[12] We analyzed 17,162 installations and 187 ZIP codes in Arizona, 80,440 installations and 1,275 ZIP codes in California, and 17,987 installations and 562 ZIP codes in New Jersey.

Data limitations

We analyzed median income data at the ZIP-code level from the U.S. Census Bureau because actual income data for each installation are not publicly available. There is an inherent amount of uncertainty in using median income data as proxies for real income data, as actual incomes associated with each installation could be higher or lower than the median income.

It should also be noted that the number of installations in the three datasets analyzed in this study does not reflect all residential solar installations within each state. As of the end of 2012, the NJCEP dataset we analyzed captured 98 percent of cumulative installed residential capacity in megawatts in New Jersey, the APS dataset covered 64 percent of cumulative installed residential capacity in Arizona, and the CSI dataset accounted for 55 percent of cumulative installed residential capacity in California.[13]

Additionally, the CSI program rebates have been declining as installed capacity reaches specific milestones. Initial rebates began at $2.50 per watt in 2007, and because the program has been so successful, the rebates are now just $0.20 per watt, as each utility participating in the program has nearly met its final capacity goals.[14] Because of these

lower rebate payments, it is likely that fewer new customers are accounted for in the CSI database, which could be especially true for wealthier customers, who may have decided to forgo the CSI application process. Therefore, some of the increase in the share of installations that have occurred in areas with lower median incomes over the past couple years could be due to the lower rebate payments.

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Endnotes

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8 Thomas E. Hoff and others, "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin" (Napa, California: Clean Power Research, L.L.C., 2006), available at http://www.ilsr.org/wp-content/uploads/2013/03/Value-of-PV-to-Austin-Energy.pdf.

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13 Solar Energy Industries Association, "U.S. Solar Market Insight 2012 Year in Review."

14 Go Solar California, "California Solar Initiative - Statewide Trigger Tracker," available at http://www.csi-trigger.com/ (last accessed September 2013).

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ADJUSTMENT SCHEDULE LFCR
LOST FIXED COST RECOVERY MECHANISM

APPLICATION

The Lost Fixed Cost Recovery ("LFCR") Mechanism shall be applied monthly to all retail Standard Offer or Direct Access service, except for Customers served under Rate Schedules E-30, E-32L, E-32 TOU L, E-34, E-35, E-36XL, and unmetered lighting schedules including E-47, E-58, E-59, and Contract 12. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The LFCR adjustment will go into effect upon Comission approval and will not be prorated. Details of how the adjustment is derived and administered can be found in the Lost Fixed Cost Recovery Mechanism Plan of Administration approved by the ACC in Decision No. 73183.

RATE

The LFCR charge will be applicable to the customer's total billed amount (not be less than zero) including all other adjustors, excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

LFCR Charge: 1.7095%

EXHIBIT
TAS C 25
Judicial notice

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Adjustment Percentage
($000)

	(A)	(B)	(C)
Line No.	**Annual Percentage Adjustment**	**Reference**	**Total**
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ 46,392
2.	Applicable Company Revenues	Schedule 2, Line 1	2,713,738
3.	% Applied to Customer's Bills	(Line 1 / Line 2)	1.7095%

Note: For the Current Period, the full revenue per customer decoupling mechanism that was proposed in APS's June 1, 2011 rate application (including all customers and offering no residential Opt-Out alternative and excluding LFCR DG charges) would have resulted in a total cumulative revenue adjustment of $78.78 million ($15.6 million less than the prior year) and average cumulative customer bill impact of 2.3971%.

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation
($000)

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1.	Applicable Company Revenues		$	2,713,738
2.	Allowed Cap %			1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	27,137
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$	45,973
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 11, Column C		-
6.	Annual Interest Rate			0.61%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)		-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	45,973
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	38,505
10.	Lost Fixed Cost Revenue - Billed[1]		$	38,086
11.	LFCR Balancing Account	(Line 9 - Line 10)	$	419
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	7,887
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	-
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.2906%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	46,392

[1]Amount billed to customers for the 12 calendar months of 2015 including Rate Rider LFCR DG

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential				
	Energy Efficiency Savings				
1.	Current Period			203,309	MWh
2.	% of Residential Customers on Opt-Out			0.277%	
3.	Excluded MWh reduction	(Line 1 * Line 2)		563	MWh
4.	Net - Current Period	(Line 1 - Line 3)		202,746	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C		175,101	MWh
6.	Verified - Prior Period			180,126	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)		5,025	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)		508,931	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)		716,702	MWh
	Distributed Generation Savings				
10.	Current Period			275,951	MWh
11.	Excluded MWh Production			1,960	MWh
12.	Net - Current Period	(Line 10 - Line 11)		273,991	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C		230,175	MWh
14.	Verified - Prior Period			230,106	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)		(69)	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)		273,922	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)		990,624	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$	0.031111	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$	30,819	
	C&I				
	Energy Efficiency Savings				
20.	Current Period			210,238	MWh
21.	Excluded MWh reduction			76,926	MWh
22.	Net - Current Period	(Line 20 - Line 21)		133,312	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C		125,187	MWh
24.	Verified - Prior Period			126,632	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)		1,445	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)		367,232	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)		501,989	MWh
	Distributed Generation Savings				
28.	Current Period			189,366	MWh
29.	MWh DG Savings from Rate Schedules Excluded from LFCR			41,292	MWh
30.	Net - Current Period	(Line 28 - Line 29)		148,074	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C		126,038	MWh
32.	Verified - Prior Period			129,438	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)		3,400	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)		151,474	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)		653,463	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$	0.023190	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$	15,154	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	**$**	**45,973**	

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation
($000)

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference		(C) Total
	Residential Customers			
1.	Distribution Revenue	Schedule 6, Line 13, Column H	$	326,735
2.	Transmission Revenue	Schedule 6, Line 13, Column I	$	65,572
3.	Total Fixed Revenue	(Line 1 + Line 2)	$	392,307
4.	MWh Billed	Schedule 6, Line 12, Column C / 1,000		12,610,002
5.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$	0.031111
	C & I Customers			
6.	Distribution Revenue	Schedule 5, Line 13, Column H	$	155,931
7.	Transmission Revenue	Schedule 5, Line 13, Column I	$	23,093
8.	Total Fixed Revenue	(Line 6 + Line 7)	$	179,024
9.	MWh Billed	Schedule 5, Line 12, Column C / 1,000		7,719,982
10.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$	0.023190

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 5: Distribution and Transmission Revenue Calculation
General Service

Line No.	(A) Rate Schedule	(B) Tariff Component	(C) Adjusted Test Year Billing Determinants	(D) Units	(E) Delivery Charge	(F) Transmission Charge	(G) Demand Stability Factor	(H) C*E*(1-G) Distribution Revenue	(I) C*F*(1-G) Transmission Revenue	(J) H+I Total Revenue
1.	E-32 XS	Summer Secondary								
2.		Delivery (1st 5000 kWh per mo.)	684,456,061	kWh	$ 0.04175	$ 0.00424	0%	$ 28,576,041	$ 2,902,094	$ 31,478,135
3.		Delivery (over 5000 kWh per mo.)	74,299,892	kWh	$ 0.01310	$ 0.00424	0%	$ 973,329	$ 315,032	$ 1,288,361
4.		Summer Primary								
5.		Delivery (1st 5000 kWh per mo.)	208,510	kWh	$ 0.03847	$ 0.00424	0%	$ 8,021	$ 884	$ 8,905
6.		Delivery (over 5000 kWh per mo.)	57,060	kWh	$ 0.00983	$ 0.00424	0%	$ 561	$ 242	$ 803
7.		Winter Secondary								
8.		Delivery (1st 5000 kWh per mo.)	593,445,292	kWh	$ 0.04168	$ 0.00424	0%	$ 24,734,800	$ 2,516,208	$ 27,251,008
9.		Delivery (over 5000 kWh per mo.)	66,031,288	kWh	$ 0.01303	$ 0.00424	0%	$ 860,388	$ 279,973	$ 1,140,361
10.		Winter Primary								
11.		Delivery (1st 5000 kWh per mo.)	289,917	kWh	$ 0.03837	$ 0.00424	0%	$ 11,124	$ 1,229	$ 12,353
12.		Delivery (over 5000 kWh per mo.)	153,071	kWh	$ 0.00974	$ 0.00424	0%	$ 1,491	$ 649	$ 2,140
13.		Sub Total	-	kW				$ -	$ -	$ -
14.			1,418,941,091	kWh				$ 55,165,755	$ 6,016,311	$ 61,182,066
15.	E-32 S	Secondary								
16.		Delivery 1st 100 kW	8,124,000	kW	$ 8.243	$ 1.585	50%	$ 33,483,066	$ 6,438,270	$ 39,921,336
17.		Delivery All Additional kW	655,000	kW	$ 3.629	$ 1.585	50%	$ 1,188,498	$ 519,088	$ 1,707,586
18.		Delivery - All kWh	2,541,774,000	kWh	$ 0.00423	$ -	0%	$ 10,751,704	$ -	$ 10,751,704
19.		Primary								
20.		Delivery 1st 100 kW	15,000	kW	$ 7.531	$ 1.585	50%	$ 56,483	$ 11,888	$ 68,371
21.		Delivery All Additional kW	46,000	kW	$ 2.917	$ 1.585	50%	$ 67,091	$ 36,455	$ 103,546
22.		Delivery - All kWh	10,208,000	kWh	$ 0.00423	$ -	0%	$ 43,180	$ -	$ 43,180
23.		Sub Total	8,840,000	kW				$ 34,795,138	$ 7,005,701	$ 41,800,839
24.			2,551,982,000	kWh				$ 10,794,884	$ -	$ 10,794,884
25.	E-32 M	Secondary								
26.		Delivery 1st 100 kW	4,680,000	kW	$ 8.650	$ 1.585	50%	$ 20,241,000	$ 3,708,900	$ 23,949,900
27.		Delivery All Additional kW	4,562,000	kW	$ 3.800	$ 1.585	50%	$ 8,667,800	$ 3,615,385	$ 12,283,185
28.		Delivery - All kWh	3,243,059,000	kWh	$ 0.00649	$ -	0%	$ 21,047,453	$ -	$ 21,047,453
29.		Primary								
30.		Delivery 1st 100 kW	33,000	kW	$ 7.903	$ 1.585	50%	$ 130,400	$ 26,153	$ 156,553
31.		Delivery All Additional kW	60,000	kW	$ 3.110	$ 1.585	50%	$ 93,300	$ 47,550	$ 140,850
32.		Delivery - All kWh	36,483,000	kWh	$ 0.00649	$ -	0%	$ 236,775	$ -	$ 236,775
33.		Transmission								
34.		Delivery 1st 100 kW	-	kW	$ 5.783	$ 1.585	50%	$ -	$ -	$ -
35.		Delivery All Additional kW	-	kW	$ 0.934	$ 1.585	50%	$ -	$ -	$ -
36.		Delivery - All kWh	-	kWh	$ 0.00649	$ -	0%	$ -	$ -	$ -
37.		Sub Total	9,335,000	kW				$ 29,132,500	$ 7,397,988	$ 36,530,488
38.			3,279,542,000	kWh				$ 21,284,228	$ -	$ 21,284,228
39.	E-32 TOU XS	Summer Secondary								
40.		Delivery On Pk (1st 5000 kWh per mo.)	628,000	kWh	$ 0.05065	$ 0.00424	0%	$ 31,808	$ 2,663	$ 34,471
41.		Delivery - All additional kWh	-	kWh	$ 0.01316	$ 0.00424	0%	$ -	$ -	$ -
42.		Delivery Off Pk (1st 5000 kWh per mo.)	1,553,000	kWh	$ 0.04174	$ 0.00424	0%	$ 64,822	$ 6,585	$ 71,407
43.		Delivery - All additional kWh	85,000	kWh	$ 0.00962	$ 0.00424	0%	$ 818	$ 360	$ 1,178
44.		Summer Primary								
45.		Delivery On Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.04730	$ 0.00424	0%	$ -	$ -	$ -
46.		Delivery - All additional kWh	-	kWh	$ 0.00902	$ 0.00424	0%	$ -	$ -	$ -
47.		Delivery Off Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.03838	$ 0.00424	0%	$ -	$ -	$ -
48.		Delivery - All additional kWh	-	kWh	$ 0.00627	$ 0.00424	0%	$ -	$ -	$ -
49.		Winter Secondary								
50.		Delivery On Pk (1st 5000 kWh per mo.)	647,000	kWh	$ 0.05057	$ 0.00424	0%	$ 32,719	$ 2,743	$ 35,462
51.		Delivery - All additional kWh	3,000	kWh	$ 0.01304	$ 0.00424	0%	$ 39	$ 13	$ 52
52.		Delivery Off Pk (1st 5000 kWh per mo.)	1,604,000	kWh	$ 0.04164	$ 0.00424	0%	$ 66,791	$ 6,801	$ 73,592
53.		Delivery - All additional kWh	89,000	kWh	$ 0.00954	$ 0.00424	0%	$ 849	$ 377	$ 1,226
54.		Winter Primary								
55.		Delivery On Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.04721	$ 0.00424	0%	$ -	$ -	$ -
56.		Delivery - All additional kWh	-	kWh	$ 0.00890	$ 0.00424	0%	$ -	$ -	$ -
57.		Delivery Off Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.03829	$ 0.00424	0%	$ -	$ -	$ -
58.		Delivery - All additional kWh	-	kWh	$ 0.00618	$ 0.00424	0%	$ -	$ -	$ -
59.		Sub Total	-	kW				$ -	$ -	$ -
60.			4,609,000	kWh				$ 197,846	$ 19,542	$ 217,388
61.	E-32 TOU S	Secondary								
62.		On Pk 1st 100 kW	94,000	kW	$ 5.775	$ 1.585	50%	$ 271,425	$ 74,495	$ 345,920
63.		On Pk all add kW	13,000	kW	$ 1.185	$ 1.585	50%	$ 7,703	$ 10,303	$ 18,006
64.		Off Pk 1st 100 kW	100,000	kW	$ 2.842	$ 1.585	50%	$ 142,100	$ 79,250	$ 221,350
65.		Off Pk all add kW	24,000	kW	$ 0.412	$ 1.585	50%	$ 4,944	$ 19,020	$ 23,964
66.		Primary								
67.		On Pk 1st 100 kW	-	kW	$ 5.317	$ 1.585	50%	$ -	$ -	$ -
68.		On Pk all add kW	-	kW	$ 1.117	$ 1.585	50%	$ -	$ -	$ -
69.		Off Pk 1st 100 kW	1,000	kW	$ 2.267	$ 1.585	50%	$ 1,134	$ 793	$ 1,927
70.		Off Pk all add kW	2,000	kW	$ 0.333	$ 1.585	50%	$ 333	$ 1,585	$ 1,918
71.		Sub Total	234,000	kW				$ 427,639	$ 185,446	$ 613,085
72.			41,567,000	kWh				$ -	$ -	$ -
73.	E-32 TOU M	Secondary								
74.		On Pk 1st 100 kW	84,000	kW	$ 8.318	$ 1.585	50%	$ 349,356	$ 66,570	$ 415,926
75.		On Pk all add kW	72,000	kW	$ 3.165	$ 1.585	50%	$ 113,940	$ 57,060	$ 171,000
76.		Off Pk 1st 100 kW	86,000	kW	$ 3.894	$ 1.585	50%	$ 167,442	$ 68,155	$ 235,597
77.		Off Pk all add kW	89,000	kW	$ 1.165	$ 1.585	50%	$ 51,843	$ 70,533	$ 122,376
		Delivery - All kWh	69,937,000	kWh	$ 0.00910	$ -	0%	$ 636,427	$ -	$ 636,427
78.		Primary								
79.		On Pk 1st 100 kW	-	kW	$ 7.803	$ 1.585	50%	$ -	$ -	$ -
80.		On Pk all add kW	-	kW	$ 3.088	$ 1.585	50%	$ -	$ -	$ -
81.		Off Pk 1st 100 kW	-	kW	$ 3.248	$ 1.585	50%	$ -	$ -	$ -
82.		Off Pk all add kW	-	kW	$ 1.076	$ 1.585	50%	$ -	$ -	$ -
		Delivery - All kWh	-	kWh	$ 0.00910	$ -	0%	$ -	$ -	$ -
83.		Transmission								
84.		On Pk 1st 100 kW	-	kW	$ 6.882	$ 1.585	50%	$ -	$ -	$ -
85.		On Pk all add kW	-	kW	$ 2.771	$ 1.585	50%	$ -	$ -	$ -

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 5: Distribution and Transmission Revenue Calculation
General Service

Line No.	(A) Rate Schedule	(B) Tariff Component	(C) Adjusted Test Year Billing Determinants	(D) Units	(E) Delivery Charge	(F) Transmission Charge	(G) Demand Stability Factor	(H) C*E*(1-G) Distribution Revenue	(I) C*F*(1-G) Transmission Revenue	(J) H+I Total Revenue
86.		Off Pk 1st 100 kW	-	kW	$ 2.519	$ 1.585	50%	$ -	$ -	$ -
87.		Off Pk all add kW	-	kW	$ 0.956	$ 1.585	50%	$ -	$ -	$ -
		Delivery - All kWh	-	kWh	$ 0.00910	$ -	0%	$ -	$ -	$ -
88.		Sub Total	331,000	kW				$ 682,581.00	$ 262,318.00	$ 944,899.00
89.			69,937,000	kWh				$ 636,427.00	$ -	$ 636,427.00
90.	E-20									
91.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
92.			36,664,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
93.		Sub Total	-	kW				$ -	$ -	$ -
94.			36,664,000	kWh				$ 871,742	$ 247,348	$ 1,119,090
95.	E-36 M	Summer Secondary								
96.		Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.04175	$ 0.00424	0%	$ -	$ -	$ -
97.		Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.01310	$ 0.00424	0%	$ -	$ -	$ -
98.		Summer Primary								
99.		Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.03847	$ 0.00424	0%	$ -	$ -	$ -
100.		Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.00983	$ 0.00424	0%	$ -	$ -	$ -
101.		Winter Secondary								
102.		Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.04168	$ 0.00424	0%	$ -	$ -	$ -
103.		Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.01303	$ 0.00424	0%	$ -	$ -	$ -
104.		Winter Primary								
105.		Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.03837	$ 0.00424	0%	$ -	$ -	$ -
106.		Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.00974	$ 0.00424	0%	$ -	$ -	$ -
107.		Secondary								
108.		Delivery 1st 100 kW	-	kW	$ 15.068	$ 1.585	50%	$ -	$ -	$ -
109.		Delivery All Additional kW	-	kW	$ 8.186	$ 1.585	50%	$ -	$ -	$ -
110.		Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
111.		Primary								
112.		Delivery 1st 100 kW	-	kW	$ 13.010	$ 1.585	50%	$ -	$ -	$ -
113.		Delivery All Additional kW	-	kW	$ 7.128	$ 1.585	50%	$ -	$ -	$ -
114.		Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
115.		Transmission								
116.		Delivery 1st 100 kW	-	kW	$ 8.203	$ 1.585	50%	$ -	$ -	$ -
117.		Delivery All Additional kW	-	kW	$ 3.024	$ 1.585	50%	$ -	$ -	$ -
118.		Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
119.		Sub Total	-	kW				$ -	$ -	$ -
120.			-	kWh				$ -	$ -	$ -
121.	E-67									
122.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
123.			3,432,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
124.		Sub Total	-	kW				$ -	$ -	$ -
125.			3,432,000	kWh				$ 98,092	$ 4,671	$ 102,763
126.	E-221									
127.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
128.			291,231,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
129.		Sub Total	-	kW				$ -	$ -	$ -
130.			291,231,000	kWh				$ 1,844,426	$ 1,953,946	$ 3,798,372
131.	E-221 8T									
132.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
133.			22,077,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
134.		Sub Total	-	kW				$ -	$ -	$ -
135.			22,077,000	kWh				$ -	$ -	$ -
136.	GS-Schools M	Secondary								
137.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
138.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
139.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
140.		Primary								
141.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
142.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
143.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
144.		Transmission								
145.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
146.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
147.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
148.		Sub Total	-	kW				$ -	$ -	$ -
149.			-	kWh				$ -	$ -	$ -
150.	GS-Schools L	Secondary								
151.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
152.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
153.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
154.		Primary								
155.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
156.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
157.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
158.		Transmission								
159.		Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
160.		Delivery All Additional kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
161.		Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
162.		Sub Total	-	kW				$ -	$ -	$ -
163.			-	kWh				$ -	$ -	$ -
164.	Total kW		18,740,000	kW				$ 65,037,858	$ 14,851,453	$ 79,889,311
165.	Total kWh		7,719,982,091	kWh				$ 90,893,400	$ 8,241,818	$ 99,135,218
166.	Total							$ 155,931,258	$ 23,093,271	$ 179,024,529

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 6: Distribution and Transmission Revenue Calculation
Residential

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
								C*E*(1-G)	C*F*(1-G)	H+I
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Transmission Charge	Demand Stability Factor	Distribution Revenue	Transmission Revenue	Total Revenue
1.	E-12									
2.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
3.			4,026,662,000	kWh	$ 0.02700	$ 0.00520	0%	$ 108,719,874	$ 20,938,642	$ 129,658,516
4.		**Sub Total**	-	**kW**				$ -	$ -	$ -
5.			**4,026,662,000**	**kWh**				**$ 108,719,874**	**$ 20,938,642**	**$ 129,658,516**
6.	ET-1									
7.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
8.			4,344,033,000	kWh	$ 0.02700	$ 0.00520	0%	$ 117,288,891	$ 22,588,972	$ 139,877,863
9.		**Sub Total**	-	**kW**				$ -	$ -	$ -
10.			**4,344,033,000**	**kWh**				**$ 117,288,891**	**$ 22,588,972**	**$ 139,877,863**
11.	ET-2									
12.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
13.			1,919,486,000	kWh	$ 0.02700	$ 0.00520	0%	$ 51,826,122	$ 9,981,327	$ 61,807,449
14.		**Sub Total**	-	**kW**				$ -	$ -	$ -
15.			**1,919,486,000**	**kWh**				**$ 51,826,122**	**$ 9,981,327**	**$ 61,807,449**
16.	ECT-1R									
17.		Summer	2,618,000	kW	$ 3.90000	$ -	50%	$ 5,105,100	$ -	$ 5,105,100
18.			751,315,000	kWh	$ 0.01540	$ 0.00520	0%	$ 11,570,251	$ 3,906,838	$ 15,477,089
19.										
20.		Winter	1,754,000	kW	$ 2.30000	$ -	50%	$ 2,017,100	$ -	$ 2,017,100
21.			467,580,000	kWh	$ 0.01700	$ 0.00520	0%	$ 7,948,860	$ 2,431,416	$ 10,380,276
22.		**Sub Total**	**4,372,000**	**kW**				**$ 7,122,200**	**$ -**	**$ 7,122,200**
23.			**1,218,895,000**	**kWh**				**$ 19,519,111**	**$ 6,338,254**	**$ 25,857,365**
24.	ECT-2									
25.		Summer	2,036,000	kW	$ 4.50000	$ -	50%	$ 4,581,000	$ -	$ 4,581,000
26.			690,590,000	kWh	$ 0.01400	$ 0.00520	0%	$ 9,668,260	$ 3,591,068	$ 13,259,328
27.										
28.		Winter	1,216,000	kW	$ 2.40000	$ -	50%	$ 1,459,200	$ -	$ 1,459,200
29.			408,035,000	kWh	$ 0.01590	$ 0.00520	0%	$ 6,487,757	$ 2,121,782	$ 8,609,539
30.		**Sub Total**	**3,252,000**	**kW**				**$ 6,040,200**	**$ -**	**$ 6,040,200**
31.			**1,098,625,000**	**kWh**				**$ 16,156,017**	**$ 5,712,850**	**$ 21,868,867**
32.	ET-SP									
33.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
34.			2,301,000	kWh	$ 0.02700	$ 0.00520	0%	$ 62,127	$ 11,965	$ 74,092
35.		**Sub Total**	-	**kW**				$ -	$ -	$ -
36.			**2,301,000**	**kWh**				**$ 62,127**	**$ 11,965**	**$ 74,092**
37.	ET-EV									
38.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
39.			-	kWh	$ 0.02700000	$ 0.00520000	0%	$ -	$ -	$ -
40.		**Sub Total**	-	**kW**				$ -	$ -	$ -
41.			-	**kWh**				$ -	$ -	$ -
42.	Total kW		**7,624,000**	**kW**				**$ 13,162,400**	**$ -**	**$ 13,162,400**
43.	Total kWh		**12,610,002,000**	**kWh**				**$ 313,572,142**	**$ 65,572,010**	**$ 379,144,152**
44.	Total							**$ 326,734,542**	**$ 65,572,010**	**$ 392,306,552**

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
LFCR Reset Impact

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Residential (Avg - All Rates)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,100				1,337	1,337	863	863
Base Rates	$ 123.90	$ 123.90			$ 161.07	$ 161.07	$ 86.72	$ 86.72
PSA	$ (4.46)	$ (4.46)			$ (5.42)	-5.42	$ (3.49)	$ (3.49)
TCA	$ 7.23	$ 7.23			$ 8.78	$ 8.78	$ 5.67	$ 5.67
RES	$ 4.42	$ 4.42			$ 4.42	$ 4.42	$ 4.42	$ 4.42
DSMAC	$ 2.03	$ 2.03			$ 2.47	$ 2.47	$ 1.59	$ 1.59
EIS	$ 0.12	$ 0.12			$ 0.15	$ 0.15	$ 0.09	$ 0.09
SBA-2	$ (0.56)	$ (0.56)			$ (0.68)	$ (0.68)	$ (0.44)	$ (0.44)
Four Corners	$ 2.52	$ 2.52			$ 3.27	$ 3.27	$ 1.76	$ 1.76
LFCR	$ 1.98	$ 2.32	$ 0.34	0.25%	$ 2.54	$ 2.98	$ 1.41	$ 1.65
Total	$ 137.18	$ 137.52	$ 0.34	0.25%	$ 176.60	$ 177.04	$ 97.73	$ 97.97

Residential (Rate E-12)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	691				780	780	602	602
Base Rates	$ 86.40	$ 86.40			$ 108.04	$ 108.04	$ 64.76	$ 64.76
PSA	$ (2.80)	$ (2.80)			$ (3.16)	-3.16	$ (2.44)	$ (2.44)
TCA	$ 4.54	$ 4.54			$ 5.12	$ 5.12	$ 3.95	$ 3.95
RES	$ 4.42	$ 4.42			$ 4.42	$ 4.42	$ 4.42	$ 4.42
DSMAC	$ 1.28	$ 1.28			$ 1.44	$ 1.44	$ 1.11	$ 1.11
EIS	$ 0.08	$ 0.08			$ 0.09	$ 0.09	$ 0.07	$ 0.07
SBA-2	$ (0.36)	$ (0.36)			$ (0.40)	$ (0.40)	$ (0.31)	$ (0.31)
Four Corners	$ 1.75	$ 1.75			$ 2.19	$ 2.19	$ 1.31	$ 1.31
LFCR	$ 1.39	$ 1.63	$ 0.24	0.25%	$ 1.72	$ 2.01	$ 1.06	$ 1.25
Total	$ 96.70	$ 96.94	$ 0.24	0.25%	$ 119.46	$ 119.75	$ 73.93	$ 74.12

Commercial XS (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,430				1,575	1,575	1,285	1,285
Base Rates	$ 202.38	$ 202.38			$ 233.37	$ 233.37	$ 171.39	$ 171.39
PSA	$ (5.79)	$ (5.79)			$ (6.37)	-6.37	$ (5.20)	$ (5.20)
TCA	$ 4.23	$ 4.23			$ 4.65	$ 4.65	$ 3.80	$ 3.80
RES	$ 15.82	$ 15.82			$ 17.42	$ 17.42	$ 14.21	$ 14.21
DSMAC	$ 2.64	$ 2.64			$ 2.91	$ 2.91	$ 2.37	$ 2.37
EIS	$ 0.16	$ 0.16			$ 0.17	$ 0.17	$ 0.14	$ 0.14
SBA-2	$ (0.74)	$ (0.74)			$ (0.81)	$ (0.81)	$ (0.66)	$ (0.66)
Four Corners	$ 4.11	$ 4.11			$ 4.74	$ 4.74	$ 3.48	$ 3.48
LFCR	$ 3.26	$ 3.81	$ 0.55	0.24%	$ 3.74	$ 4.38	$ 2.77	$ 3.24
Total	$ 226.07	$ 226.62	$ 0.55	0.24%	$ 259.82	$ 260.46	$ 192.30	$ 192.77

ARIZONA PUBLIC SERVICE COMPANY
LFCR Reset Impact

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Commercial S (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	7,182				7,752	7,752	6,612	6,612
Averge kW per Month	23.7				26.8	26.8	20.6	20.6
Base Rates	$ 842.33	$ 842.33			$ 987.28	$ 987.28	$ 697.38	$ 697.38
PSA	$ (29.08)	$ (29.08)			$ (31.38)	$ (31.38)	$ (26.77)	$ (26.77)
TCA	$ 22.45	$ 22.45			$ 25.38	$ 25.38	$ 19.51	$ 19.51
RES	$ 79.44	$ 79.44			$ 85.74	$ 85.74	$ 73.13	$ 73.13
DSMAC	$ 16.50	$ 16.50			$ 18.65	$ 18.65	$ 14.34	$ 14.34
EIS	$ 0.78	$ 0.78			$ 0.84	$ 0.84	$ 0.72	$ 0.72
SBA-2	$ (3.68)	$ (3.68)			$ (3.97)	$ (3.97)	$ (3.39)	$ (3.39)
Four Corners	$ 17.10	$ 17.10			$ 20.04	$ 20.04	$ 14.16	$ 14.16
LFCR	$ 13.80	$ 16.17	$ 2.37	0.25%	$ 16.09	$ 18.85	$ 11.51	$ 13.49
Total	$ 959.64	$ 962.01	$ 2.37	0.25%	$ 1,118.67	$ 1,121.43	$ 800.59	$ 802.57

Commercial - M (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	62,238	62,238			68,381	68,381	56,094	56,094
Averge kW per Month	195.7				209.5	209.5	181.8	181.8
Base Rates	$ 6,431.10	$ 6,431.10			$ 7,407.24	$ 7,407.24	$ 5,454.95	$ 5,454.95
PSA	$ (252.00)	$ (252.00)			$ (276.87)	$ (276.87)	$ (227.13)	$ (227.13)
TCA	$ 185.28	$ 185.28			$ 198.40	$ 198.40	$ 172.16	$ 172.16
RES	$ 276.50	$ 276.50			$ 276.50	$ 276.50	$ 276.50	$ 276.50
DSMAC	$ 136.17	$ 136.17			$ 145.81	$ 145.81	$ 126.53	$ 126.53
EIS	$ 6.78	$ 6.78			$ 7.45	$ 7.45	$ 6.11	$ 6.11
SBA-2	$ (31.87)	$ (31.87)			$ (35.01)	$ (35.01)	$ (28.72)	$ (28.72)
Four Corners	$ 130.56	$ 130.56			$ 150.37	$ 150.37	$ 110.74	$ 110.74
LFCR	$ 100.43	$ 117.66	$ 17.23	0.25%	$ 114.90	$ 134.60	$ 85.96	$ 100.71
Total	$ 6,982.95	$ 7,000.18	$ 17.23	0.25%	$ 7,988.79	$ 8,008.49	$ 5,977.10	$ 5,991.85

Commercial - L (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	290,507	290,507			314,925	314,925	266,089	266,089
Averge kW per Month	716.5				795	795	638	638
Base Rates	$ 24,707.54	$ 24,707.54			$ 29,453.69	$ 29,453.69	$ 19,961.38	$ 19,961.38
PSA	$ (1,176.27)	$ (1,176.27)			$ (1,275.13)	$ (1,275.13)	$ (1,077.40)	$ (1,077.40)
TCA	$ 678.53	$ 678.53			$ 752.87	$ 752.87	$ 604.19	$ 604.19
RES	$ 553.00	$ 553.00			$ 553.00	$ 553.00	$ 553.00	$ 553.00
DSMAC	$ 498.69	$ 498.69			$ 553.32	$ 553.32	$ 444.05	$ 444.05
EIS	$ 31.67	$ 31.67			$ 34.33	$ 34.33	$ 29.00	$ 29.00
SBA-2	$ (148.74)	$ (148.74)			$ (161.24)	$ (161.24)	$ (136.24)	$ (136.24)
Four Corners	$ 501.57	$ 501.57			$ 597.91	$ 597.91	$ 405.22	$ 405.22
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ 25,645.99	$ 25,645.99	$ -	0.00%	$ 30,508.75	$ 30,508.75	$ 20,783.20	$ 20,783.20

ARIZONA PUBLIC SERVICE COMPANY
LFCR Reset Impact

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Industrial - XL (E-34,35)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	3,693,933	3,693,933			3,841,873	3,841,873	3,545,992	3,545,992
Averge kW per Month	6,369.5				6,681	6,681	6,058	6,058
Base Rates	$ 251,228.00	$ 251,228.00			$ 262,539.00	$ 262,539.00	$ 239,917.00	$ 239,917.00
PSA	$ (14,956.74)	$ (14,956.74)			$ (15,555.75)	$ (15,555.75)	$ (14,357.72)	$ (14,357.72)
TCA	$ 7,496.91	$ 7,496.91			$ 7,863.54	$ 7,863.54	$ 7,130.27	$ 7,130.27
RES	$ 3,594.00	$ 3,594.00			$ 3,594.00	$ 3,594.00	$ 3,594.00	$ 3,594.00
DSMAC	$ 4,433.18	$ 4,433.18			$ 4,649.98	$ 4,649.98	$ 4,216.37	$ 4,216.37
EIS	$ 402.64	$ 402.64			$ 418.76	$ 418.76	$ 386.51	$ 386.51
SBA-2	$ (1,891.30)	$ (1,891.30)			$ (1,967.04)	$ (1,967.04)	$ (1,815.55)	$ (1,815.55)
Four Corners	$ 5,099.93	$ 5,099.93			$ 5,329.54	$ 5,329.54	$ 4,870.32	$ 4,870.32
LFCR	$ -	$ -			$ -	$ -	$ -	$ -
Total	$ 255,406.62	$ 255,406.62	$ -	0.00%	$ 266,872.03	$ 266,872.03	$ 243,941.20	$ 243,941.20

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. All Adjustor levels in effect as of January 1, 2016.
(2) Bill includes the projected impact to customers of the reset of the LFCR adjustor.

EXHIBIT
TASC 26

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

DOCKET NO. E-00000J-14-0023

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

THE ALLIANCE FOR SOLAR CHOICE'S (TASC) NOTICE OF FILING DIRECT TESTIMONY OF B. THOMAS BEACH

The Alliance for Solar Choice ("TASC") hereby provides notice of filing the Direct Testimony of ~~B~~ R. Thomas Beach in the above referenced matter.

RESPECTFULLY SUBMITTED this 25th day of February, 2016.

Court S. Rich
Attorney for The Alliance for Solar Choice

Original and 13 copies filed on this 15th day of February, 2016 with:

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By: _____

Executive Summary

This testimony responds to the Commission's request that parties file proposals on how to value distributed generation resources in Arizona. My testimony proposes a benefit-cost methodology for valuing DG resources that builds upon the widely-used, industry-standard approach to assessing the cost-effectiveness of other types of demand-side resources. I illustrate this methodology with a new analysis of the benefits and costs of solar DG for Arizona Public Service ("APS"), which is **Exhibit 2** to this testimony.

There is a developing consensus in the utility industry on the best practices for designing benefit-cost analyses of net metering and distributed resources, a consensus which draws upon the similar analyses which have become standard practice for other types of demand-side resources. These analyses assess the benefits and costs of these resources from multiple perspectives, including those of the principal stakeholders in DG development, including (1) participating customer-generators, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in developing DG technologies.

This testimony also presents a close analysis of the net metering transaction, for several reasons. First, it illuminates how DG differs from other demand-side resources. DG customers are not just consumers of power, but also at times produce power for export to the utility system. Second, I discuss why the essence of net metering is valuing the power which DG customers will export to the grid. Third, I dispel several common myths about net metering, including the misplaced ideas that NEM customers use the grid more than regular utility customers, that a NEM customer with a low or zero bill means that the customer has not paid for its use of the grid, and that the grid serves to "store" DG output for future consumption. In sum, I suggest that the appropriate framework for assessing the relative benefits and costs of net metering is to focus on the value that customer receives for the electricity that is exported from their premises.

The Commission should adopt a benefit/cost methodology for NEM and DG that has four key attributes:

1. Examine and balance the benefits and costs from the multiple perspectives of the key stakeholders.
2. Consider a comprehensive list of benefits and costs.
3. Use a long-term, life-cycle analysis.
4. Focus on NEM exports.

I discuss recent benefit-cost studies of net-metered solar resources in Nevada, California, and Mississippi, which also have examined the benefits and costs from these multiple perspectives. I also discuss the unfortunate recent results in Nevada, when the Nevada commission moved to rely solely on a short-term, cost-of-service framework that does not share any of these attributes. I recommend that the methodology adopted in Arizona should take care to include all four of these key features, with the details of Arizona's approach tailored to its specific loads, resources, and costs.

The testimony briefly reviews the specific benefits and costs that should be examined and quantified in establishing the value of DG. All of these benefits and costs have been quantified in other similar studies, and well-accepted techniques are available for this task. If there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that benefit or cost, but to examine several cases that span a range of reasonable values for this benefit or cost.

Accompanying this testimony is a new study of the benefits and costs of solar DG for Arizona Public Service, which applies TASC's recommended methodology to the example of a specific utility in Arizona. This study concludes:

- **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

- There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

- The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

- The **benefits of solar DG in APS's service territory are higher for west-facing systems**. If there is a concern about the cost of DG to non-participating ratepayers, west-facing systems should be encouraged and incentivized, particularly for residential customers.

- The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

The cost-effectiveness test results for APS's residential and commercial markets are shown in the following figures.

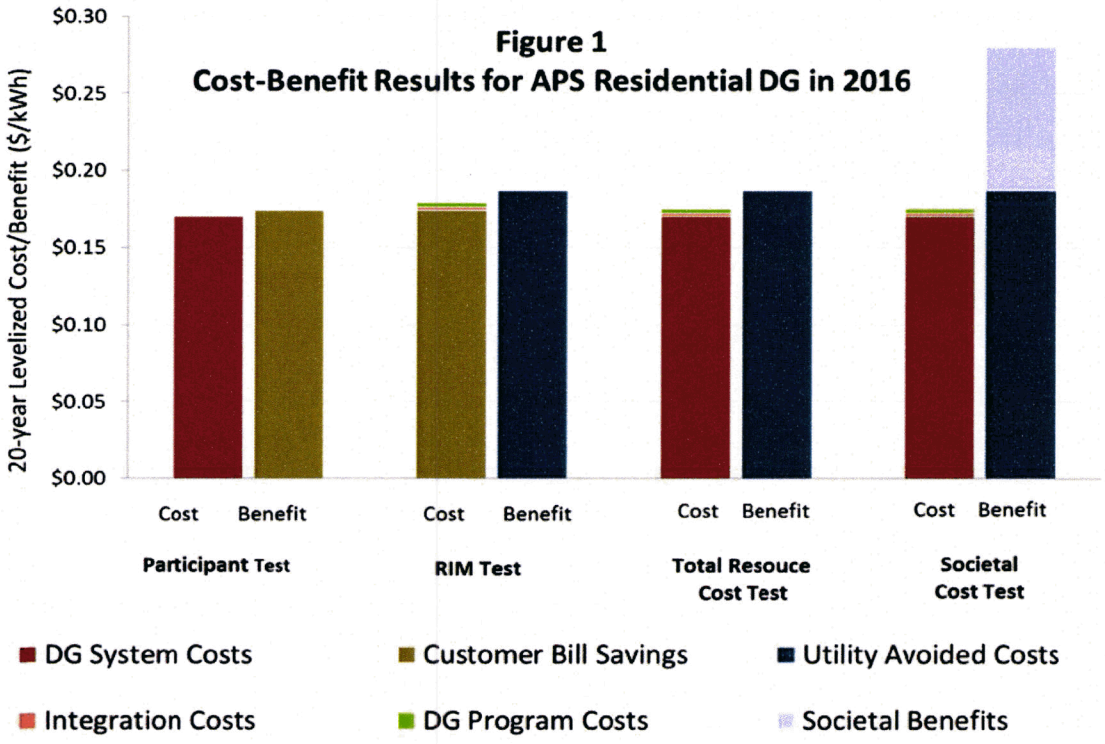
Figure 1
Cost-Benefit Results for APS Residential DG in 2016
20-year Levelized Cost/Benefit ($/kWh)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Cost
Benefit
Participant Test
RIM Test
Total Resouce Cost Test
Societal Cost Test
DG System Costs
Customer Bill Savings
Utility Avoided Costs
Integration Costs
DG Program Costs
Societal Benefits

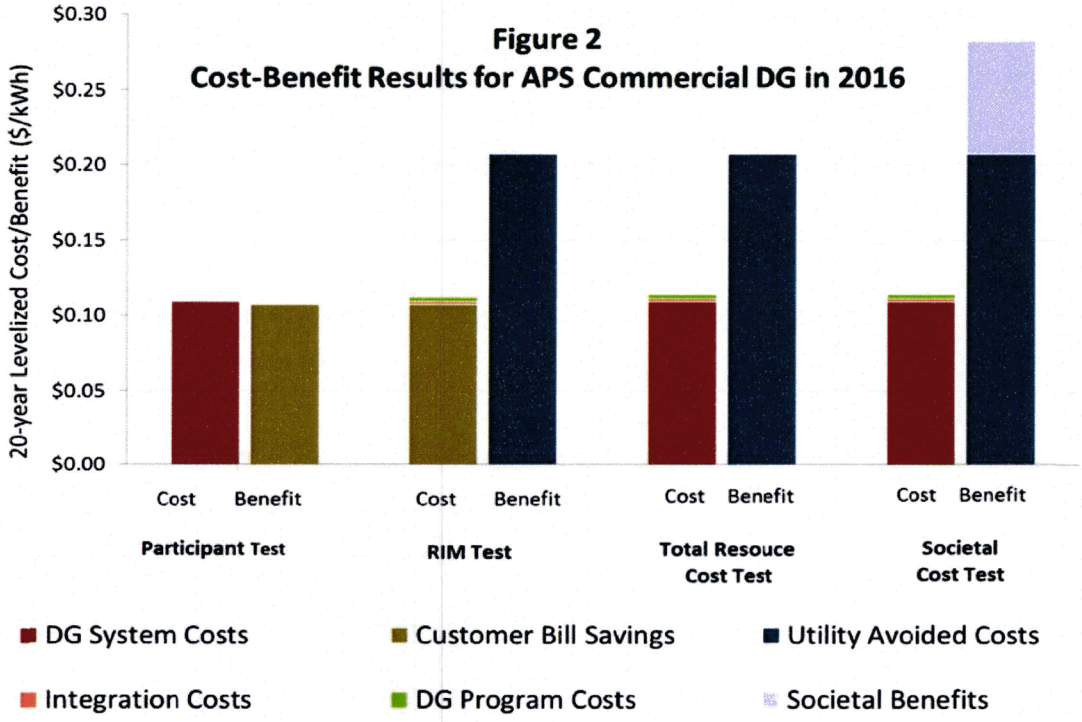
Figure 2
Cost-Benefit Results for APS Commercial DG in 2016
20-year Levelized Cost/Benefit ($/kWh)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Cost
Benefit
Participant Test
RIM Test
Total Resouce Cost Test
Societal Cost Test
DG System Costs
Customer Bill Savings
Utility Avoided Costs
Integration Costs
DG Program Costs
Societal Benefits

The testimony next discusses how the results of the adopted methodology can be used to make cost of service or rate design changes, if necessary, that impact the balance of the interests of the affected stakeholders. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DG, such as a minimum bill. Fixed charges or rate design changes that apply only to DG customers should be avoided, due to problems with customer acceptance, undue discrimination, and the future potential for customer bypass of the utility system.

The last section of the testimony discusses comparisons between the costs of utility-scale and rooftop solar systems. Utility-scale solar has lower capital costs, as a result of economies of scale. However, this is not an apples-to-apples comparison, because the two types of solar do not provide the same energy product. Rooftop solar provides a retail product, while utility-scale solar supplies a wholesale product. The retail, rooftop product has been delivered to load, whereas the wholesale, utility-scale product has not. Thus, for a fair comparison between the two resources, at a minimum one must add to the cost of utility-scale solar the marginal costs associated with delivering this power to the customers that can be served by solar DG located on their own roofs. Furthermore, these resources differ in their value for Renewable Energy Standard compliance, and rooftop solar provides additional societal benefits to the local environment and economy.

Finally, there are important policy reasons to treat rooftop solar equitably, so that consumers continue to have the freedom to exercise a competitive choice and to become more engaged and self-reliant in providing for their energy needs.

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Exhibit 1 – CV of R. Thomas Beach
Exhibit 2 -- The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)

I. Introduction / 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 your experience and qualifications.

A2: My experience and qualifications are described in my *curriculum vitae*, attached as **Exhibit 1**. As reflected in my CV, I have more than 30 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony on numerous occasions before state regulatory commissions in Arizona, California, Colorado, Idaho, Minnesota, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, Georgia, South Carolina, Texas, Utah, Vermont and Virginia. My CV includes a list of the formal testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities.

Q3: Please describe more specifically your experience on benefit-cost issues concerning distributed generation.

A3: In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Idaho, North Carolina, Oregon, Utah, and Nevada. With respect to benefit-cost issues concerning renewable distributed generation ("DG"), I have sponsored testimony on net energy metering ("NEM") and solar economics in California, Colorado, Idaho, Minnesota, New Mexico, North

Carolina, South Carolina, Texas, and Virginia. In the last three years, I have co-authored benefit-cost studies of NEM or distributed solar generation in Arizona (focusing on Arizona Public Service ["APS"]), Colorado, North Carolina, and California. I also co-authored a chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation resources.

Q4: On whose behalf are you testifying in this proceeding?

A4: I am testifying on behalf of The Alliance for Solar Choice ("TASC").

II. Background

Q5: Why is the Commission considering proposals for a cost-benefit methodology through this proceeding?

A5: The Commission initiated this generic investigation to review NEM issues and to help inform future Commission policy on the value that DG installations bring to the grid. On October 20, 2015, the Commission ordered that an evidentiary hearing be held in this generic docket, at which the parties should present testimony with "their proposals regarding cost of service to DG customers and value of DG, including any studies and methodologies."

Q6: Is your testimony limited to the "value of DG" aspect of this proceeding?

A6: My testimony focuses on how the Commission should establish the long-term value of DG, through an analysis of the benefits and costs of DG technologies. In that regard I sponsor both this testimony on the methodology to determine the value of DG as well as a study that applies this recommended approach to a specific Arizona utility, APS. I also comment on how and why the results of this methodology should inform any further investigation of the cost of service and the

rates that are applied to DG customers, or of future changes to the structure of NEM in Arizona.

III. Proposal for a Benefit-Cost Methodology for Net-Metered DG

A. National Context: Toward a Consistent Approach

Q7: Is there a developing consensus on the best practices for designing benefit-cost analyses of behind-the-meter DG resources, including solar photovoltaic (PV) systems, that should inform how the Commission undertakes this analysis?

A7: Yes, there is. In this regard, the first and perhaps most important observation is that the issues raised by the growth of demand-side DG are not new. The same issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole arose when state regulators and utilities began to manage demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs.[1] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of NEM and demand-side DG more broadly, as state commissions recognize that evaluating the costs and

[1] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF .

benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below. "+" denotes a benefit; "-" a cost.

Table 1: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	–		–
Customer Bill Savings or Utility Lost Revenues	+	–	
Benefits (Avoided Costs) -- Energy -- Hedging/market mitigation -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		–	–

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. A program will need to pass the Participant test if it is to attract customers by offering them an economic benefit for their participation – thus, their bill savings and tax benefits should be comparable to the cost of participating. The program also should be a net benefit as a resource to the utility system or society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of the program to its benefits. In the TRC Test,

those benefits are principally the costs which the utility can avoid from the reduction in demand for electricity. The Societal Test adds the broader benefits to citizens as whole, benefits that may not be reflected in utility rates. The Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-participating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties are likely to benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

B. Experience in Other States: Nevada, California, and Mississippi

Q8: Can you provide examples of other state commissions which have developed analyses of NEM from the three perspectives which you have described?

A8: Yes. The Public Utilities Commission of Nevada ("PUCN") adopted this multi-perspective approach in the net metering study which it released on July 1, 2014.[2] The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure 3** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.[3]

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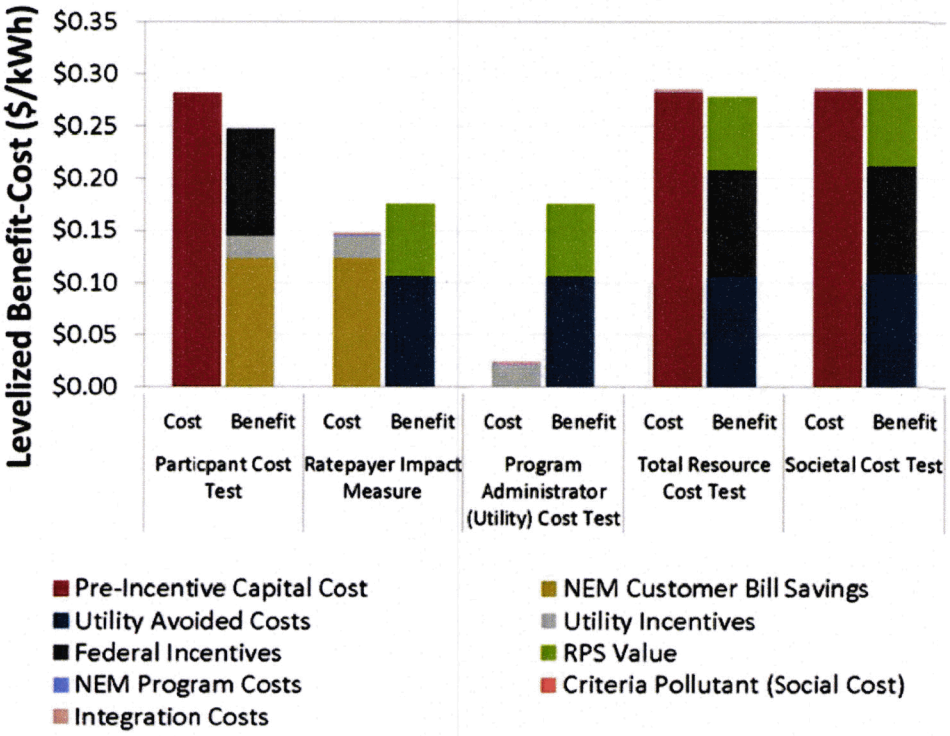
[2] The PUCN's net metering study, including the spreadsheet models used in the study, can be found at: http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ .

[3] This figure is from the "Results" tab of the "Nevada Public Tool" model, with the model set to produce results for solar PV and for the going-forward period of 2014-2016.

Figure 3: *Public Utilities Commission of Nevada NEM Benefit-Cost Results*



Notably, the Nevada study showed that NEM is cost-effective for non-participating ratepayers (*i.e.*, the benefits in the RIM test exceeded the costs), while the costs are somewhat higher than the benefits for participants (*i.e.*, for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study demonstrated that NEM at the full retail rate, without any further rate design modifications, achieved that desired "rough justice" balance of interests in Nevada.

Q9: Did the Nevada Commission subsequently move away from the use of a long-term benefit-cost approach to analyze NEM in that state?

A9: Yes, it did. In 2015, in response to new legislation, the PUCN reviewed a study from NV Energy that was limited to the short-term cost of service for residential

and small commercial customers who install solar DG. The PUCN's recent decision on December 23, 2015 accepted the results of that study, and, based on that evidence, found that there was a significant cost shift from non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of 2.6 cents per kWh. The PUCN took this action even though its order found that there are the following 11 components to the value of DG (based on an adopted stipulation on NEM issues from South Carolina), and that it was only able to quantify the first two components of DG value in the adopted 2.6 cents per kWh export rate:

1. Avoided energy costs
2. Line losses
3. Avoided capacity
4. Ancillary services
5. Transmission and distribution capacity
6. Avoided criteria pollutants
7. Avoided CO_2 emission costs
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administration costs
11. Environmental costs[4]

Q10: What has been the result of the PUCN decision?

A10: The reduction in the export rate and the increased fixed charge have reduced the bill savings available to NEM customers in Nevada by 40% or more. DG is no longer economic for new systems, and existing customers who expected modest savings from their solar investments now face substantial added costs for electric service. Even though the PUCN has subsequently decided to phase-in the new DG rates over a 12-year period, the elimination of NEM and, in particular, the reduction in the export rate, has decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies.[5] The

[4] See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at pp. 66-67 and 95-96.
[5] See *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of TASC*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

controversy has been particularly heated because the PUCN applied the new rates to existing solar customers as well as to prospective ones. The changes have sparked significant public outcry, a ballot initiative, and lawsuits from unhappy customers whose investments in renewable DG have been severely and unexpectedly been made uneconomic.[6]

Q11: Did the California Public Utilities Commission recently review the benefits and costs of net metered DG?

A11: Yes. The investor-owned utilities in California are approaching that state's 5% cap on NEM systems. In 2015, the California Commission asked parties to analyze their proposals for a NEM successor tariff using a common "Public Tool" spreadsheet program similar to the Nevada NEM benefit-cost model. Like the Nevada model, the California Public Tool analyses a proposed tariff from multiple perspectives, using all of the SPM's cost-effectiveness tests and looking at the long-term, life-cycle costs and benefits. The CPUC received detailed analyses of NEM benefits and costs using the Public Tool from a variety of parties. In January 2016, the California commission decided to extend NEM in California until a further review in 2019, with certain changes such as requiring NEM customers to be on time-of-use ("TOU") rates, removing certain public benefit charges from export rates, and requiring NEM customers to pay interconnection costs. The CPUC's order does not rely on the Public Tool analyses, because important information related to both costs (rate design changes) and benefits (locational benefits on the distribution grid and societal benefits) remain under development in other CPUC proceedings. However, the CPUC made clear that it intends to continue to refine and to use this SPM-based, long-term benefit-cost approach in its future evaluations of NEM and DG.[7]

Q12: Do you have any other recent examples?

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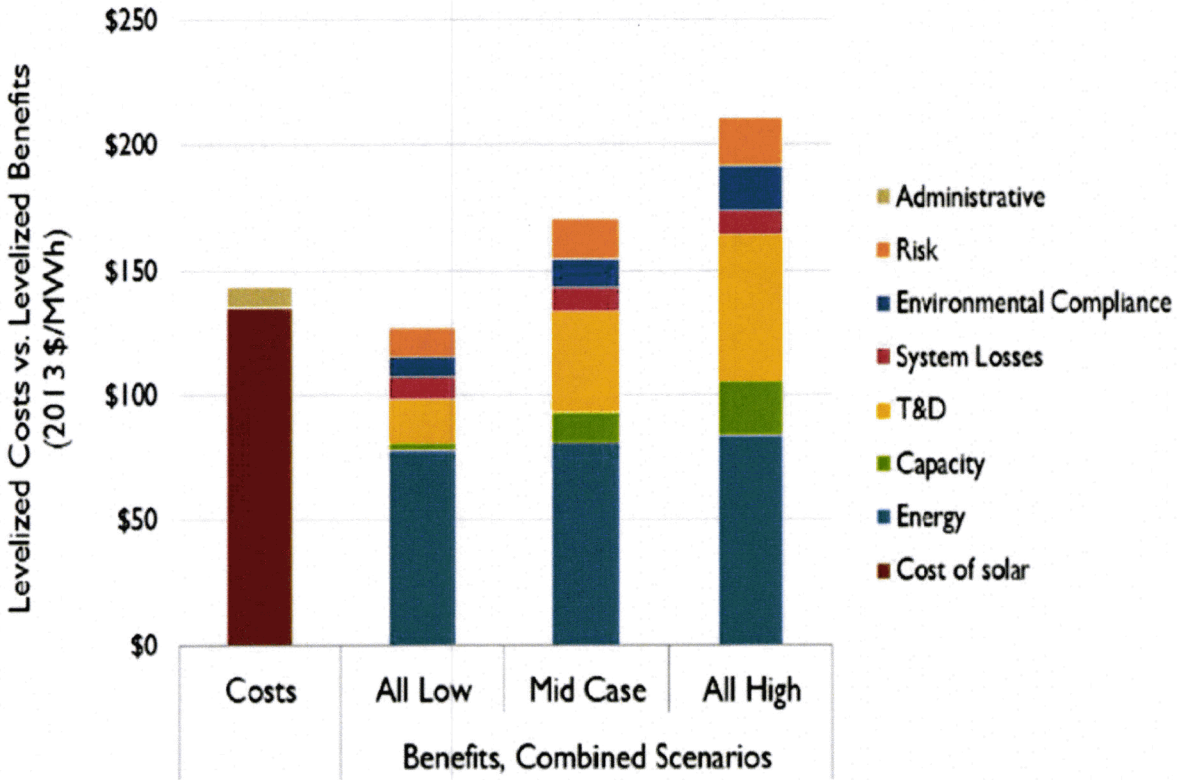
[6] For example, see "Regulators vote against grandfather clause for existing solar customers" (*Las Vegas Sun*, February 12, 2016), available at http://m.lasvegassun.com/news/2016/feb/12/regulators-vote-against-grandfather-clause-for-exi/#.VsN4d5tCIss.twitter.

[7] See CPUC Decision 16-01-044, at pp. 48-50, 54-61, and 80-82.

A12: Yes. The Public Service Commission of Mississippi completed a NEM benefit/cost analysis in 2014, and NEM is being implemented for the first time in Mississippi.[8] As in the Nevada NEM study, the Mississippi study considered the three principal perspectives discussed above, with a focus on the TRC test because that test best captures the benefits and cost for the state as a whole from this new resource. The Mississippi study also used a 25-year time horizon. The following figure summarizes the mid-case costs and benefits from Mississippi's TRC analysis, plus the maximum low and high sensitivity cases for the benefits.

Figure 4: *Public Service Commission of Mississippi NEM Study Results*



As a result of this analysis, the Mississippi study concluded that net metered solar projects will provide a net benefit to Mississippi in almost all of the cases considered. However, the study's analysis of the Participant cost test expressed

[8] Elizabeth A. Stanton, et al., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* (Synapse Energy Economics for the Public Service Commission of Mississippi, released September 19, 2014); hereafter "Mississippi Study." Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf .

concern that NEM bill savings at the retail rate will not provide adequate benefits to drive significant adoption of solar DG in the state. As a result, the study suggested that solar customers should be compensated at a rate higher than retail rates. This higher rate would be based on the utilities' avoided cost benefits, so that it would not shift costs to non-participants.[9] Finally, the Mississippi Study criticized the use of the traditional RIM test, particularly in the context of a new NEM program. The problem with the RIM test is that the cost shift measured by the RIM test is simply a re-allocation of costs which the utilities have already incurred and which are not incremental costs resulting from the NEM program. Due to this limitation, the RIM test should not be used to judge the merits of the new NEM program.[10]

C. The DG Customer as "Prosumer"

Q13: The framework you have proposed and illustrated with examples from the Nevada, California, and Mississippi commissions draws on benefit/cost analyses used for other types of demand-side programs. But isn't there a crucial difference between DG and other demand-side resources: DG is generation that at times can supply power to the grid, whereas EE and DR only reduce the demand for power?

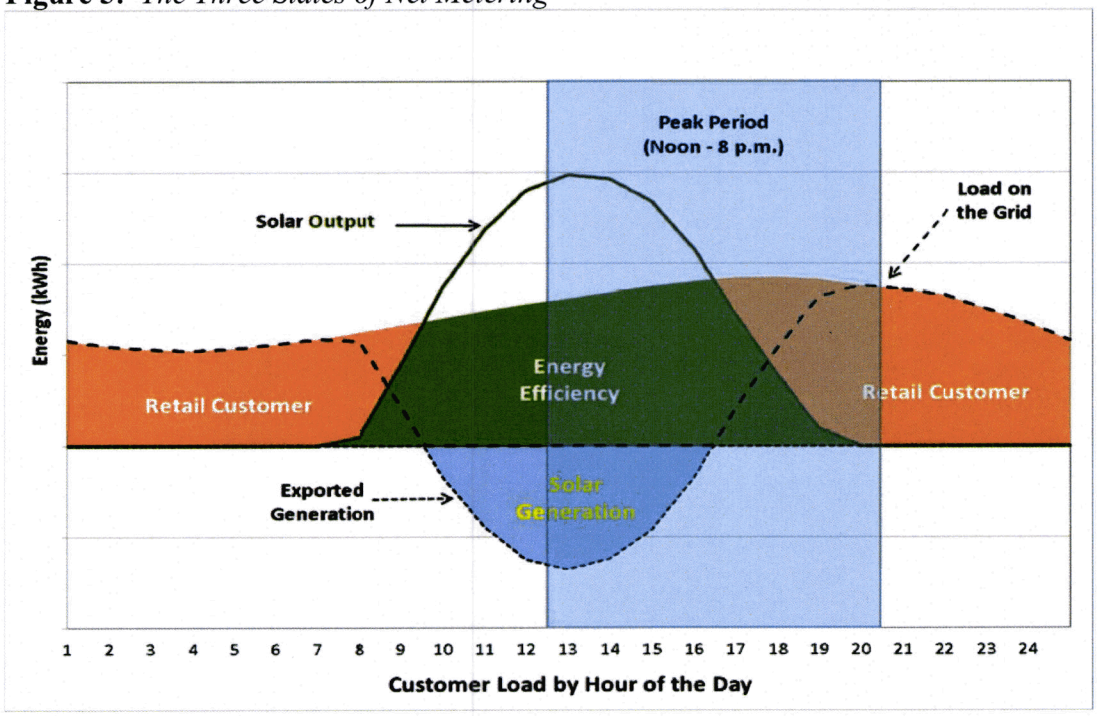
A13: This difference exists, is important, and should be considered. DG located behind the meter will both reduce the demand for power from the utility, and, at times, will supply power to the utility. When a DG system produces more power than the on-site load requires, the excess is exported to the grid, and the DG owner is no longer a consumer, but becomes a supplier (i.e. a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role. Appreciating these multiple roles is important, and should be considered in establishing the framework for evaluating the benefits and costs of DG.

[9] Mississippi Study, at 49-50.
[10] *Ibid.*, at 41-43 and Figure 18.

Q14: Please explain these multiple roles in more detail, using the example of a typical residential NEM customer.

A14: To illustrate in detail how net metering works, **Figure 5** shows the three different "states" of a residential net-metered PV system over the course of a day:

Figure 5: *The Three States of Net Metering*



- **The "Retail Customer State."** There is no PV production – for example, at night. At this time, the customer is a regular utility customer, receiving its electricity from the grid. The utility meter rolls forward, and the customer pays the full retail rate for this power.

- **The "Energy Efficiency State."** In this state, the sun is up, and there is some PV production but not enough to serve all of the customer's instantaneous load. The customer is supplied with power from the solar PV system as well as with power from the utility. Onsite solar reduces the customer's load on the utility's system in the same fashion as an energy efficiency measure. None of the solar customer's PV production flows out to the utility grid, the meter continues to roll forward, and the customer will pay the utility the full retail rate for his net usage from the grid during these hours.

- **The "Power Export, or Net Metering, State."** In this state, the sun is high overhead, and PV production exceeds the customer's instantaneous

use. The on-site solar power serves the customer's entire load, and excess PV generation flows onto the utility's distribution circuit. The utility meter runs backward, producing a net metering credit for the solar customer. In these hours, the solar customer is no longer just a consumer, but is also a producer of power, i.e. a generator. The net metering credit is the solar customer's compensation for the generation it is supplying to the grid. As a matter of physics, the exported power will serve neighboring loads with 100% renewable energy, displacing power that the utility would otherwise generate at a more distant power plant and deliver to that local area over its transmission and distribution system.

This state is the only one in which the customer's generation touches the utility's distribution system or in which a bill credit is produced. In typical PV installations, the percentage of solar output exported to the utility is, on average, about one-third of total PV production; the export percentage can vary above or below this average, depending on the size of the PV system and the hourly profile of the host customer's load. Residential solar customers tend to export a higher percentage of their power output than commercial solar customers.

Q15: What do you conclude from this description?

A15: Net metering only provides bill credits for power exported to the grid. On-site generation from customer-sited PV that is not exported, i.e., electricity generated in the Energy Efficiency State in Figure 3, is not compensated through net metering. In that case, the customer simply uses his on-site generation to reduce his load, and to the utility the installation of such a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day. In fact, if the solar customer did not export power to the grid and 100% of the solar output was consumed on-site, there would be no need for NEM.

Thus, the essence of NEM is the ability of a customer with a solar PV system to "run the meter backwards" when the customer has more generation than the on-site load and is serving as a generation source for the utility system. When the meter runs backward, the DG customer receives credit for his generation exports in the form of a retail rate credit from the utility. In the accounting used to calculate the DG customer's bill, the customer can use these credits to offset the cost of usage from the grid when the meter runs forward.

Q16: Please discuss the implications for evaluating NEM of the fact that most DG customers are "qualifying facilities" (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

A16: As generators, renewable DG customers typically have legal status as QFs under PURPA. As a result, the serving utility is required under this federal law to do the following:

- to interconnect with a customer's renewable DG system,
- to allow a DG customer to use the output of his system to offset his on-site load, and
- to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs.[11]

These provisions of federal law are independent of whether a state has adopted NEM; thus, the adoption of NEM only impacts the accounting credits which the customer-generator receives for power exports to the grid, and the analysis of the economics of NEM should focus on those exports.

An important implication of the focus on exports is that, even if it is found that there is a "cost shift" from solar DG customers to non-participating ratepayers, any calculation of such a cost shift should only consider the power exported by DG customers, not the DG output that a customer uses on-site, behind the meter, without the power ever touching the grid. As noted above, DG exports are typically a minority, often just 30% to 40%, of DG production. There are always cost shifts when a customer reduces the demand placed on the grid, or shifts load to a different time period, as the result of many types of actions that utilities and regulators encourage – energy efficiency, demand response, or using DG to serve your own load. Such actions by DG customers should not be singled out, penalized, or treated differently than other steps that consumers take to manage their energy demand and reduce their utility bills.

[11] The PURPA requirements can be found in 18 CFR §292.303.

D. Exploding Common Myths about Net Metering

Q17: Does the fact that DG customers can be both consumers and producers of electricity mean that they make more use of the utility system than regular utility customers?

A17: No. The DG customer either imports power from, or exports power to, the utility's distribution system. When the DG customer imports power from the utility, the customer is using the utility system (including generation, transmission, and distribution), and the meter runs forward. The customer pays the standard tariff rate for that service, including the utility's standard charges for generation and for delivery of the power over the utility's transmission and distribution ("T&D") system.

With exported power, it is not the solar customer who is using the utility system, it is the utility and the solar customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. This is no different than when the utility buys power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's customers. Instead, that delivery service becomes the utility's responsibility when it accepts and takes title to the exported power at the generator's meter. As a generator, the only utility costs for which the generator may be responsible are the incremental costs of interconnecting to the utility system to enable the transfer of generation (and these are often paid by the customer-generator).

As a matter of fact, the utility will save money by using the solar customer's exported power to serve the neighbors, because the utility will avoid the costs of the power that the utility would otherwise have had to generate at a more distant power plant and deliver to that local area over its transmission and distribution system. The essential public policy issue with net metering is whether these "avoided costs" which the utility saves are less than, equal to, or greater than the

sum of (1) the net metering credit that the utility provides to the solar customer and (2) the utility's integration and program costs.

Q18: So if a NEM customer ends up with a small, zero, or even negative bill at the end of a month, does this mean that the NEM customer is not paying for the utility service the customer is receiving?

A18: Absolutely not. First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. If the solar customer ends the month with a small or zero bill from the utility, this is the result of crediting the customer for the value of the power which the customer supplies to the utility (from exporting power and running the meter backwards). These credits can offset the solar customer's costs of utility service when the customer imports power and the meter runs forward. However, these credits are not the result of the solar customer's use of the utility system; instead, they are the means to account for the exported generation which the solar customer has provided to the utility at the meter. Thus, the solar customer has paid fully for all actual use which the customer has made of the utility system, even though the customer's net bill at the end of the year may be small or even zero. There is the public policy issue of whether the bill credits for exported power at the retail rate are the right credit for those exports – and this case focuses on the methodology for analyzing this issue – but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Q19: Doesn't the utility incur costs to "stand by" to serve a solar customer when the solar customer is exporting power to the grid?

A19: No. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may suddenly impose a load on the system. As a consumer, a solar customer looks like a

customer who uses power in the morning, evening, and at night, but who turns everything off in the middle of the day, as illustrated by the dashed "Load on the Grid" line in Figure 3. Such a customer may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage. But these load fluctuations are something the utility is well-prepared to serve on an aggregate basis, and the costs of such normal "stand by" service are included in the utility's regular rates.

Similarly, a solar customer may suddenly impose a demand on the system if a cloud temporarily covers the sun in the middle of the day. Again, however, this variability is manageable due to the small sizes and geographic diversity of solar DG systems – for example, at the time one PV system is being shaded, another will be coming back into full sunlight.

It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the power demand that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of meeting this added variability is one of the factors considered in solar integration studies, such as the several such studies that APS has conducted.[12] These studies, as well as others done in other states,[13] show that such costs are low at the current level of solar DG penetration.[14]

Q20: Doesn't the utility incur costs to store the excess kWh produced by NEM systems, allowing the NEM customer to "bank" kWh which the customer uses later when the meter is rolling forward?

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[12] For example, see Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

[13] *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014); hereafter the "Duke Integration Study."

[14] For example, the Duke Integration Study calculates that, with 673 MW of PV capacity on the Duke utility systems in 2014, integration costs are about $0.0015 per kWh. See Table 2.5 and Figure 2.51.

A20: No. Net metering does not involve the storage of electricity, or of energy in any form. This idea is one of the common myths of net metering. Again, the NEM customer is both a consumer and generator of electricity. When the NEM customer is a generator, exporting power in excess of the onsite load, as a matter of physics that generation is immediately consumed by nearby customers. In no way is the power stored for later use. When the solar customer later consumes power from the grid – for example, after the sun sets – the power used is generated and transmitted by the utility at that time. The fact that NEM credits from exports are used to offset the costs of subsequent usage simply represents an accounting transaction – offsetting a credit with a debit on the customer's account by changing the direction that the meter is recording; it does not represent any actual use of the grid to "store" or "bank" electrons or energy.

E. Key Attributes of a DG Benefit-Cost Methodology

Q21: Please discuss the key attributes of a methodology to assess the benefits and costs of net metered DG resources.

A21: There are four key attributes:

1. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** As discussed above, it is important that the Commission assess the benefits and costs of net metering from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM customers, and other ratepayers – so that the regulator can balance all of these important interests. Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility.

2. **Consider a comprehensive list of benefits and costs.** The location, diversity, and technologies of DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA. Renewable DG projects produce power in many small (less than 1 MW) installations that are widely distributed across the utility system. The power is produced and consumed on the distribution system;[15] indeed, each net-metered DG project is generally associated with a

[15] It is possible that, at high penetrations, DG output to a distribution circuit could exceed the minimum load on the circuit, as has occurred at some locations in Hawaii where, for example, more than 15% of

load at least as large as the DG project's output,[16] which will limit the amount of power than is exported to the grid. For example, an important attribute of DG is its ability to serve loads without the use of the transmission system. Accordingly, an analysis of DG benefits should consider the avoided costs for transmission and distribution losses and capacity. Renewable DG also will avoid the costs associated with environmental compliance at marginal fossil-fueled power plants. On the cost side, the analysis should consider whether solar or wind DG will result in new costs to integrate these variable resources. The next section of this testimony discusses in more detail the specific benefits and costs that should be considered and that can be quantified.

3. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new EE program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The same time frame should be used to assess the benefits and costs of DG.

4. **Focus on NEM exports.** This testimony has explained how the retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption. From a legal perspective, PURPA requires the utility to interconnect with the DG customers and to allow the DG customer, at the customer's election, to use its privately-funded generation to serve its own load, on its own private property. It is only when the customer exports power to the utility – power to which the utility takes title at the meter and uses to serve other customers – that the question arises of how to compensate the DG customer for that power. This is the essential question that net metering answers, and the focus of the net metering analysis should be determining a credit for NEM exports that is fair to all affected parties.

IV. Specific Quantifiable Benefits and Costs

Q22: Please list and provide comments on the specific benefits and costs that should be quantified in the net metering methodology.

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customers on the islands of Oahu and Maui have installed solar. Such penetrations are not expected to be reached in Arizona for many years.

[16] Like many states, Arizona limits the size of NEM systems.

A22: There are several literature reviews or meta-studies which have reviewed the existing NEM/DG benefit/cost studies and have summarized the benefits and costs included in this growing literature:

- A 2013 literature review from the Vermont Commission.[17]
- The Rocky Mountain Institute's (RMI) 2013 meta-analysis of solar DG benefit and cost studies.[18]
- The New York State Energy Research and Development Authority (NYSERDA) recently conducted a literature review of NEM benefit/cost studies, with assistance from E3, in preparation for a NEM study in New York.[19]

Based on this literature, several recent studies have formulated recommended approaches to conducting such analyses, including the specific benefits and costs that should be considered.[20] These lists of benefits and costs are also consistent with the list, cited by Commissioner Little in his December 22, 2015 letter to this docket, that was assembled by Timothy James of the W.P. Carey School of Business at Arizona State University. Finally, cost effectiveness analyses of other types of demand-side programs also draw upon the same categories of benefits and costs, although the fact that DG is generation that can be exported to the grid introduces the new category of integration costs.

Based on the above sources and our prior experience with such studies, **Tables 2 and 3** list the specific benefits and costs, respectively, that should be quantified in the Commission's net metering methodology, along with brief comments on the methodology for the quantification of each specific category.

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[17] This literature review, as well as the report and analysis of net metering that the Vermont Commission completed, are available at http://publicservice.vermont.gov/topics/renewable_energy/net_metering .

[18] Rocky Mountain Institute (RMI), "A Review of Solar PV Benefit and Cost Studies" (July 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

[19] See the November 10, 2014 NYSERDA presentation listed at http://ny-sun.ny.gov/About/Stakeholder-Meetings.aspx .

[20] Interstate Renewable Energy Council and Rabago Energy, *A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) and Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits* (prepared for the Advanced Energy Economy Institute, September 2014).

1 **Table 2:** *Avoided Cost Benefits (for TRC, Societal, and RIM Tests)*

NEM Benefit Category	Description	Comments on Methodology
Avoided Energy	Change in the variable costs of the marginal system resource, including fuel use and variable O&M, associated with the adoption of DG.	Typically calculated from market energy prices (in deregulated markets), from production cost analyses (for regulated monopoly utilities), or from the energy costs of the proxy marginal resource. Calculation should be granular enough to calculate avoided energy costs of DG resources accurately. These energy costs should be adjusted for the appropriate energy losses (see below).
Avoided Generating Capacity	Change in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of DG.	Forecast of marginal generation capacity costs calculated from market capacity prices (in deregulated markets), from the cost of the least expensive new capacity resource – typically a new combustion turbine peaker (for regulated monopoly utilities), or from the capacity cost of the proxy marginal resource. These capacity costs should be based on public, transparent data, should be adjusted for the appropriate losses (see below), and should reflect the capacity contribution of each type of renewable DG resource.
Avoided Line Losses	Change in electricity losses from the points of generation to the points of delivery associated with the adoption of DG.	Applies to both energy and generating capacity. Should be based on marginal line loss data and DG generation profiles. As a first approximation, marginal line losses are double the system average losses used in cost of service studies and tariffs.
Avoided Ancillary Services	Change in the costs of services like operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of DG.	These costs can be avoided if such reserves are procured based on loads that DG will reduce. Future DG technologies like "smart inverters" may provide services such as voltage support.
Avoided T&D Capacity	Change in costs associated with expanding/replacing/upgrading T&D capacity associated with the adoption of DG.	Based on marginal capacity costs to expand/replace/upgrade capacity on a utility's T&D system. Contribution of a DG resource to avoiding transmission or distribution capacity will depend on the contribution of DG to reducing peak loads on the transmission or distribution systems. This analysis will become more location-specific as one moves to lower voltages on the distribution system, where distribution feeders will peak at different times.
Avoided Environmental Costs	Change in costs associated with mitigation of SO_x, NO_x, and PM-2.5 emissions or with waste disposal costs (e.g. coal ash) due to the change in production from each IOU's marginal generating resources as a result of the adoption of DG generation.	Can be included in the Avoided Energy component.
Avoided Carbon Emissions	Change in costs to mitigate CO_2 or equivalent emissions due to the change in production from each IOU's marginal generating resources associated with the adoption of DG.	Based on estimates of the value of carbon emission reductions from utility integrated resource plans (IRPs) or from regulatory agencies with jurisdiction over such emissions. Such reductions can have quantifiable value to ratepayers through avoiding direct emission costs (as in cap & trade

		markets) or through the costs of resource choices intended to reduce carbon emissions (such as the replacement of coal with natural gas or the construction of carbon-free nuclear or renewable capacity.
Fuel Hedge	Costs to lock in the future price of fuel to match the fixed-price attribute of renewable DG.	Can be approximated through the use of forward natural gas prices to forecast future avoided energy costs, plus the transaction costs of such hedging.
Market Price Mitigation	Reduction in energy and capacity wholesale market prices as a result of lower demand resulting from DG adoption.	This benefit of demand-side resources has been quantified in certain U.S. markets (New England and California).
Avoided Renewables	Reduction in above-market generation costs associated with the utility's acquisition of renewable resources, if DG will contribute to meeting the utility's renewable procurement goals.	This benefit will apply to the extent that renewable DG meets a state goal that otherwise would be met with utility-owned or contracted resources.
Societal Benefits (for only the Societal Test)	Benefits for citizens of the utility's service territory or state that are not reflected directly in customer's energy costs.	Lower environmental costs from... • Damages due to climate change • Consumption or withdrawal of scarce water resources • Land use impacts Health benefits from.... • Lower criteria air emissions Economic benefits from... • Fewer power outages • Greater local economic activity

Table 3: *Costs of DG Programs (for TRC and RIM Tests)*

NEM Cost Category	Description	Comments on Methodology
For TRC Test...		
DG Resource	Capital and O&M costs of the DG resource.	
Integration	Increased costs for regulation and operating reserves to integrate variable renewable DG resources.	Integration costs should be those attributable to DG that are incremental to the costs to meet load variability.
Administrative / Interconnection	Utility costs to administer the NEM/DG program, as well as utility costs to interconnect DG resources that are not paid by the DG customer.	Should include the incremental costs associated with net metering above those required for regular billing, as well as other administrative costs. Interconnection costs should not include such costs if they are paid by the DG customer itself.
For RIM Test...		
Lost Revenues	Bill credits provided to NEM customers for exported energy.	Will vary depending on the tariff under which the DG customer takes service.
Integration	Same as above	
Administrative/ Interconnection	Same as above	

Q23: Do you have any general observations on these specific categories of benefits and costs?

A23: Yes. First, all of the above categories of benefits and costs are quantifiable, and have been quantified in other NEM or DG benefit/cost studies.

Second, the quantification of these benefits may require data and/or calculations that the utilities may not produce today in the normal course of business. For example, not all utilities calculate marginal line losses or marginal T&D capacity costs, although many do, and there are well-accepted techniques to perform these calculations.

Third, to the extent that studies of relatively complex issues – such as solar or wind integration costs – have yet to be performed, reasonable values for these costs can be derived from such studies performed for other utilities.

Finally, if there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category. For example, although the costs for mitigating carbon emissions are uncertain, the IRPs of the Arizona utilities make clear that these costs are not zero for ratepayers, because the utilities are planning today, and spending money today, to reduce their carbon emissions through the replacement of older coal plants with new natural gas-fired generation. For example, the selected case in the 2014 APS IRP includes reductions in the utility's fleet of aging coal plants, and their replacement with new gas-fired and renewable resources. The APS 2014 IRP is based on CO_2 emissions costs of $13 per ton in 2020, escalating to almost $16 per ton in 2029.[21]

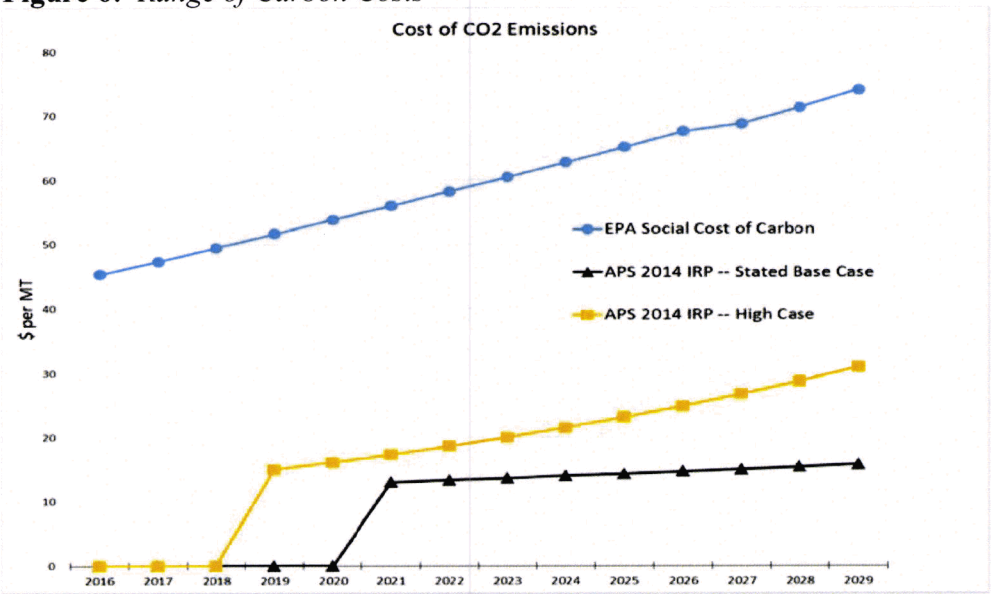
Further, the EPA's proposed regulations of greenhouse gas (GHG) emissions from power plants under Section 111(d) of the Clean Air Act indicate that the federal government may regulate such emissions based on the administration's

[21] APS 2014 IRP, at Figure 15.

social cost of carbon (SCC) values. The EPA proposal increases the certainty that the utilities will incur significant future costs for reducing carbon emissions.

All of the above considerations underscore the point that a reasonable assumption for future carbon costs is not zero, but should consider a range of possible future mitigation costs. Such a range is shown in **Figure 6**, with carbon costs varying from those that APS has assumed in its 2014 IRP up to, in the high case, the federal SCC values.

Figure 6: *Range of Carbon Costs*



V. New Benefit-Cost Study of DG in Arizona: APS

Q24: Have you performed a benefit-cost study of solar DG for an Arizona utility?

A24: Yes, I have. **Exhibit 2** to this testimony is a new study of the benefits and costs of solar DG on the APS system which expands and updates the study Crossborder Energy conducted in 2013. This study follows the general approach discussed above, including the use of multiple perspectives, a comprehensive list of benefits and costs, and a long-term analysis that focuses on generation exports.

Q25: What are the key conclusions of the APS study?

A25: The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

3. **Significant rate design changes for residential DG customers**, such as requiring solar DG customers to take service under the ECT-2 TOU rate with demand charges, **would upset this balance**.

3. The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system. Removing rate design barriers such as excessive demand charges would be one way to assist the commercial solar market in Arizona.

4. The benefits of solar DG in APS's service territory are **higher for west-facing systems.** If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

VI. Application of the Benefit-Cost Methodology to Determine Rates

Q26: How should the analysis which you have outlined above be used to determine the rates and charges which will apply to NEM customers?

A26: Any new charge or rate design applicable to net-metered customers should be tested to ensure that, after it is applied, DG will remain a viable economic proposition for participating ratepayers, the utility system, and the state as a whole, while not imposing undue upward pressure on the rates of non-participants. Such a balancing test should use a long-term benefit-cost analysis from multiple perspectives, because DG is an important long-term resource whose economics should be assessed over its full economic life, in the same way that other resource options are assessed.

Q27: Are there important lessons from other states in terms of how the results of a cost-benefit analysis of NEM may differ among different types and classes of customers?

A27: Yes. The impacts of net metering on non-participating ratepayers will vary significantly across customer classes. For example, the costs of NEM are typically lower for commercial and industrial (C&I) classes than for residential customers, for several reasons. First, C&I rates tend to be lower than residential rates. Second, the solar DG systems of C&I customers tend to export less power to the grid than residential systems, because the diurnal load profile of C&I customers often is a better match for the profile of solar output and because the DG systems installed by C&I customers typically are smaller relative to the size of the on-site load. Finally, rate design has a major impact on the bill savings that NEM customers can realize, and thus on the lost revenues that are the major cost of NEM for non-participating ratepayers. C&I rate designs often recover a significant portion of the utility's costs through monthly customer and demand charges that are difficult for C&I customers to avoid. Cost studies adopted by the California PUC have demonstrated that demand charge structures actually overcharge solar customers relative to the costs that they impose on the system,

and undervalue the peaking capacity that solar DG provides. As a result, SCE and other California utilities have designed rate options with reduced demand charges but correspondingly higher volumetric time-of-use rates, and make those rate options available to C&I customers who install solar.[22]

Q28: Should customer-generators be placed into their own rate classes?

A28: No. Customer-generators should not be placed into a separate class without sufficient data to justify distinct treatment. It cannot be assumed that, after installing DG, customers will become significantly different than other customers in the class. In general, data from many states show that adding solar tends to change a larger-than-average customer into a smaller-than-average one, but both pre-and post-solar customers are well within the range of sizes typical of the residential class.[23]

Q29: If the Commission's analysis finds that there is a cost shift from customer-generators to non-participating ratepayers that is large enough to require mitigation, what are the recommended rate design approaches to remedying this problem?

A29: There are several. Impacts on non-participants are most likely to be a concern in the residential market, because residential solar systems export a higher percentage of their output and because most of the residential cost of service is

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[22] See California PUC Decision No. 14-12-080, adopting Option R rates for PG&E after a fully-litigated proceeding; Decision No. 13-03-031 (March 21, 2013), at p. 31, discussing Option R rates for Medium and Large Power customers; and CPUC Decision No. 09-08-028 (August 20, 2009), at p. 22, first implementing Option R rates for SCE's Medium and Large Power customers who install solar.

[23] In 2014, the Colorado PUC has held workshops on net metering issues. Data from those workshops showed that the typical residential customer in Colorado who installs solar tends to have greater usage than an average customer, with an average monthly pre-solar bill of $126 compared to the average residential bill of $77 per month. After adding solar, the typical solar customer's bill drops to $50 per month. This information is based on data from solar customers on the Public Service of Colorado system. See "On-Site Solar Industry Answer to Questions set forth in Attachment A of Commission Decision No. C14-0776-I," filed July 21, 2014 in Colorado PUC Docket No. 14M-0235E, at pp. 8-9.

In 2014, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that "[t]hese facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment." See Utah PSC, Order issued August 29, 2014 in Docket No. 13-035-184, at p. 62.

recovered through volumetric rates. The preferred rate design solutions are the following:

- Encourage increased adoption of **time-of-use rates** that align rates more closely to the changes in the utility's costs over the course of a day.[24]

- Adopt a monthly **minimum bill** to recover customer-related costs, thus ensuring that all customers make a minimum contribution to the costs of the utility infrastructure that serves them.

- Remove **public benefit charges** from the NEM export rate, so that all customers contribute to these public purpose programs on the equitable basis of the power they take from the utility system.[25]

These solutions are preferable for the following reasons:

- **Address the central equity issue.** Minimum bills, for example, ensure that all customers make a minimum contribution to the utility infrastructure that serves them. The minimum bill can be set to cover the utility's customer-related costs (for metering, billing, and customer account services) which clearly do not vary with usage. In this way, they address directly the issue of equity between participating and non-participating ratepayers by ensuring that all customers contribute equally to such costs. Similarly, it is equitable for all customers to contribute to public purpose programs on the same basis, that is, based on the amount of service which they take from the utility system.

- **Consistent with cost causation.** TOU rates align rates more closely with the utility's underlying costs than do flat volumetric rates. A minimum bill can be set to assure recovery from all customers of customer-related costs which do not vary with usage. Thus, both TOU rates and minimum bills are consistent with cost causation principles.

- **Encourages customer choice.** Because a minimum bill only imposes a floor on the customer's bill and does not apply if usage remains above the minimum bill level, it provides the greatest scope for customers to impact their energy bills by exercising their free-market choice to participate in self-generation, energy efficiency, or demand response. Similarly, TOU rates send more accurate price signals to customers concerning both the

[24] This can include on-peak volumetric rates that recover capacity-related costs. Residential TOU rates should be kept simple and promoted through outreach and education programs, to ensure customer acceptance. Residential demand charges should be avoided due to their complexity, lack of time sensitivity, and unfamiliarity for residential customers. California has mandated that, once the state's 5% NEM cap is reached, succeeding NEM customers must elect a TOU rates.

[25] California and Nevada have implemented this modification to NEM export rates.

value of their DG output and when it is best to either consume or conserve energy.

- **Customer acceptance.** California, which has the nation's largest distributed solar market, has adopted a $10 per month residential minimum bill for the large electric utilities in that state, and the minimum bill was recently increased in Hawaii, where solar penetration is far higher than any other state. In contrast, attempts to implement monthly fixed charges on solar customers have not been well-received in other states, and have been perceived as efforts to tax solar production such that it would no longer be economic.[26] In essence, minimum bills are perceived as a fair balance between allowing customer choice and ensuring that all customers make an equitable contribution to the costs of utility infrastructure. Significantly, although California and Nevada recently issued very different decisions on net metering, both commissions rejected proposals to apply demand charges to residential solar customers due to concerns with customer acceptance.[27]

- **Non-discrimination.** Many states, including Arizona, have statutory prohibitions against undue discrimination in the design of utility rates.[28] If fixed charges are raised for all residential customers, there can be adverse bill impacts on all low-usage customers, including low-income ratepayers. A minimum bill is more likely to avoid such problems, as it will apply to a relatively small number of non-net-metered customers.

- **Avoid competitive bypass.** A minimum bill can address impacts on non-participants by providing DG vendors with a signal to reduce the sizing of DG systems to keep customers above the minimum bill level, thus reducing the costs of net metering for other ratepayers. This still allows scope for customer choice of DG for usage above the minimum bill level. In contrast, if a fixed charge on residential DG is set too high, as DG and on-site storage technologies continue to develop and as their costs continue to fall, the response of consumers ultimately may be to "cut the cord" completely from utility service, as has happened with landline telephone service in many areas. In my opinion, such a result would be unfortunate, because the utility grid would lose important benefits that DG and on-site storage could provide for all ratepayers, and DG customers would lose the still-important benefits of interconnection to the grid.

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[26] For example, Idaho PUC, Final Order No. 32846 in Case No. IPC-E-12-27 (July 3, 2013), at pp. 3-5.
[27] See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at p. 91, also CPUC Decision 16-01-044, at pp. 75 and 79.
[28] Ariz. Const. Article XV, § 12.

VII. Utility-scale and Rooftop Solar

Q30: It is sometimes argued that, because utility-scale solar benefits from economies of scale and thus has lower capital costs than smaller rooftop systems, utilities should encourage utility-scale solar to the exclusion of rooftop systems. Do the capital cost differences between utility-scale and rooftop solar represent the relative costs to ratepayers for these resources?

A30: No, they do not, because rooftop and utility-scale solar systems do not provide ratepayers with the same product. Rooftop solar provides a retail product, while utility-scale solar supplies a wholesale product. The majority of the output of a rooftop solar facility provides power directly to end-use retail loads, behind the meter, where it displaces retail power from the utility. A minority of power is exported to the distribution grid, where it immediately serves neighboring loads, also displacing retail power from the utility. In most states, the DG customer is compensated for this power at the retail rate, through net energy metering. In contrast, utility-scale solar projects supply wholesale power to the utility, delivering power to the high-voltage transmission system and competing with other sources of wholesale power.

Q31: Explain how to compare the differences between these products.

A31: The retail, rooftop product has been delivered to load, whereas the wholesale, utility-scale product has not. Thus, for an apples-to-apples comparison between the two resources, one must add to the cost of utility-scale solar, at a minimum, the marginal costs associated with delivering this power to the same customers that can be served by rooftop solar. The correct rate to use in this comparison is the marginal cost for transmission and distribution which the utility avoids if rooftop solar supplies a customer and his neighbors, thus avoiding the need for the utility to provide delivery service from a more remote wholesale generation source.

Although the locational difference between utility-scale and rooftop solar is the most apparent distinction between these two types of solar, there are other differences that bear on the comparative value of these resources, including the value of these resources in meeting the demand for renewable power. Solar generation contributes to meeting Renewable Portfolio Standard ("RPS") requirements in many states. Each state with an RPS has its own unique rules for counting a renewable resource's contribution to RPS requirements. For example, some states, such as Arizona, have set-asides for renewable DG; others, like Nevada, have adopted multipliers for DG in determining DG's compliance with RPS needs. In addition, rooftop solar output reduces the utilities' sales, and thus further lowers RPS requirements (and ratepayer costs) which are tied to an increasing percentage of sales.

Further, rooftop solar provides additional societal benefits compared to utility-scale solar, including greater economic benefits for the communities which have a vibrant local solar installation industry and the resiliency benefits of local power production. These are quantified in the accompanying study on APS. Rooftop solar also uses the built environment, avoiding the land use and biological impacts of the significant land areas that are required by both utility-scale solar projects and the associated transmission facilities used to deliver that generation.

Q32: Are there any other important policy reasons why a state should maintain a supportive environment for customer-sited, distributed renewable generation?

A32: Yes. Rooftop solar and other renewable distributed energy technologies allow customers to take greater responsibility for their supply of electricity, compared to traditional service from the monopoly utility.

There are many benefits to a technology that allows customers greater choice in how they obtain their electricity. These include:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability in the near future of customer-sited storage paired with rooftop solar, energy efficient appliances, and load management technologies, this competition will only intensify, given that the combination of solar and storage in the future may offer an electric supply whose quality and reliability is comparable to utility service.

- **Grid Services.** With deployment of smart inverters in 2016, rooftop solar systems can provide voltage services, reactive power and other grid services. In addition, by reducing load on individual circuits, rooftop solar systems reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it. All of these additional values are difficult to quantify because there are not currently markets for these services, and utilities do not have an incentive to procure these types of services from third-party providers.

- **Enhanced Reliability and Resiliency.** 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 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 also reduces the risk of outages due to transmission or distribution system failures. Most electric system interruptions result from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost efficiency improvements to your premises. Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we have seen recently in Nevada, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

The benefits of choice listed above are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar.

Q33: Does this conclude your prepared direct testimony?

A33: Yes, it does.

Exhibit 1

Curriculum Vitae of R. Thomas Beach

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., and Canada.

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).
https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

- *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

Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

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

1. 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.*

April 25, 2014:

http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443

June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

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)
https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *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

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) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *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.

EXHIBIT 2

Crossborder Energy
Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)

R. Thomas Beach
Patrick G. McGuire

February 25, 2016

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Attachment 1 -- *Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants*

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

This report provides a new benefit-cost analysis of the impacts of solar distributed generation (DG) on ratepayers in the service territory of Arizona Public Service (APS). The Arizona Corporation Commission has initiated a generic investigation in Docket No. E-00000J-14-0023 to review net energy metering (NEM) issues and to help inform future Commission policy on the value that DG installations bring to the grid. On October 20, 2015, the Commission ordered that an evidentiary hearing be held in this generic docket; among the issues to be heard are the value and costs of DG related to Arizona Public Service Company's (APS) provision of service to DG and non-DG customers. This report contributes to the Commission's investigation by presenting a new study of the benefits and costs of solar DG in the APS service territory. This study builds upon and updates the study that Crossborder Energy presented at a series of technical conferences on DG valuation that APS held in 2013,[1] as well as our presentation to the workshop that the Commission held on May 7, 2014.

This report provides a comprehensive benefit-cost analysis of demand-side solar in APS's service territory. This analysis has the following key attributes:

1. **Multiple perspectives.** Examine and balance the benefits and costs of solar DG from the perspectives of all of the key stakeholders – DG customers, other ratepayers, and the system and society as a whole – because all of these stakeholders constitute the public interest in DG development. As a result, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry.
2. Consider a **comprehensive list of benefits and costs**.
3. Use **a long-term, life-cycle analysis** that covers the useful life of a solar DG system, which is at least 20 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.
4. Focus on **NEM exports**, because it is those exports that differentiate DG customers from other types of demand-side resources.

This report relies on data from APS's 2014 Integrated Resource Plan (2014 IRP),[2] which provides the long-term data set that is the starting point for this analysis. We have supplemented the 2014 IRP with data from discovery, from prior studies of the value of DG and renewable generation in Arizona and the western U.S., and from current data from the regional gas and electric markets in which APS operates. Our approach to valuing solar DG also draws upon relevant analyses that have been conducted in other states, including the "public tools" for evaluating net metered DG that have been developed in Nevada and California.[3]

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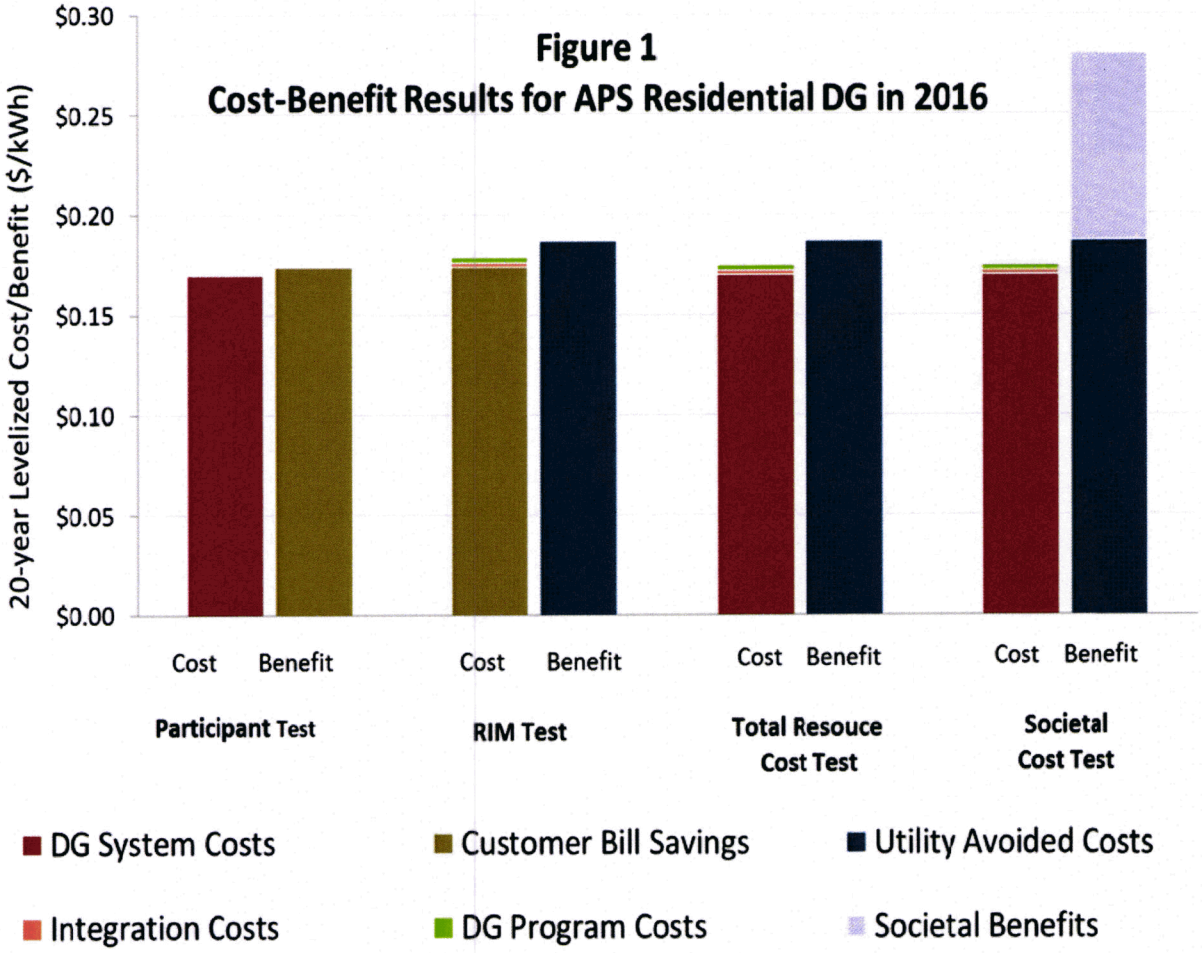
[1] Crossborder Energy, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 8, 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service.

[2] The APS 2014 IRP is available at https://www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resource-planning.aspx.

[3] See the Public Utilities Commission of Nevada's (PUCN) 2014 net metering study at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. The California Public Utilities Commission's Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=3934.

The costs of solar DG for APS's non-participating ratepayers are principally the lost revenues for the utility from solar DG customers who use their on-site solar generation to serve their own loads and who export excess output back into the grid, thus running the meter backward using net energy metering (NEM). To determine these costs, we calculate the 20-year levelized rate credits that both residential and business customers who install solar DG will realize from the output of their net-metered systems, net of the existing monthly installed capacity fee assessed on DG customers. We use an assumed rate escalation based on the future rates estimated in the 2014 IRP, plus the rate of inflation for the customer and delivery costs not covered in the IRP. Finally, on the cost side, we also include an estimate of APS's costs to integrate solar DG into the grid.

Our work concludes that the benefits of residential DG on the APS system are in balance with the costs, such that new residential DG customers will not impose a burden on APS's ratepayers. The following figure and table summarize the results of our application of the primary cost-effectiveness tests to residential solar DG on the APS system.



For APS's commercial customers, the benefits of DG significantly exceed the costs, as shown below.

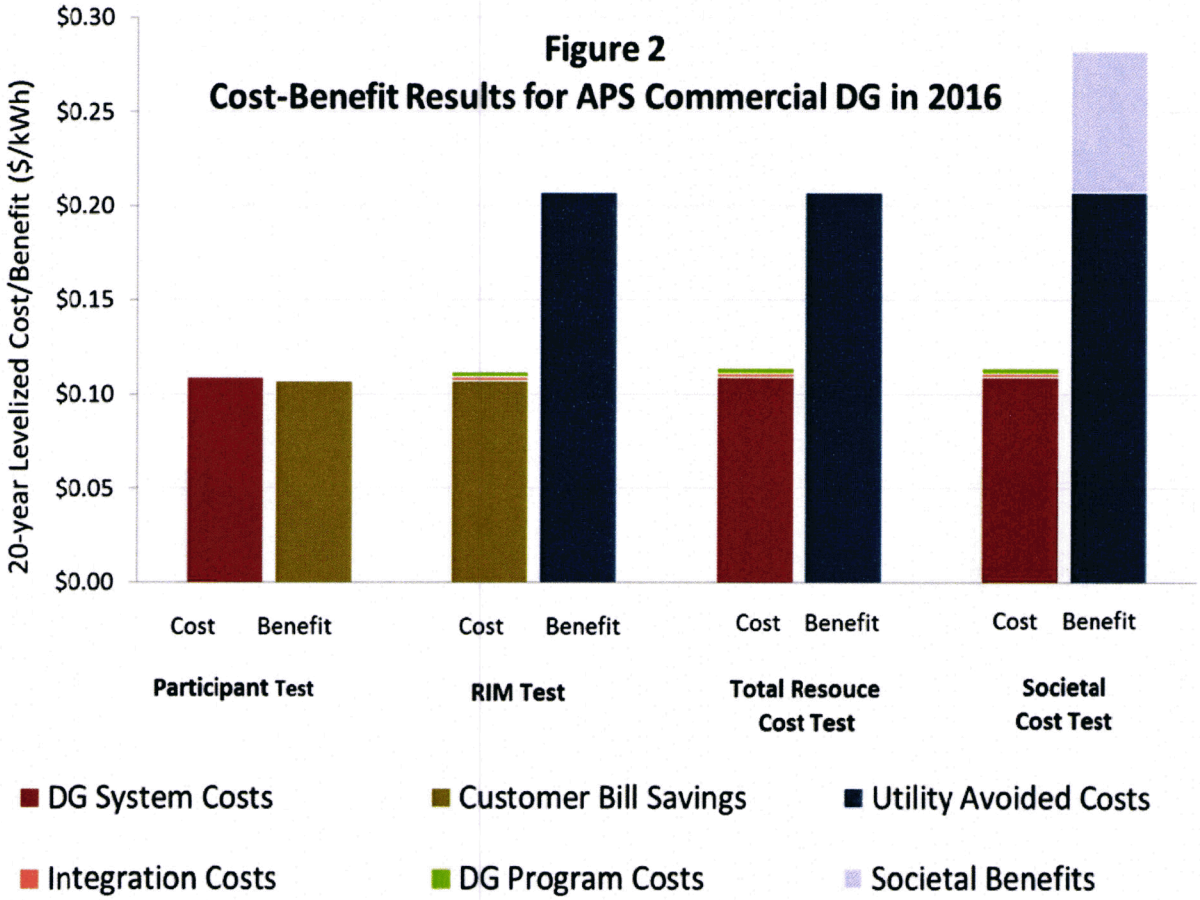


Table 1: *Benefits and Costs of Solar DG on the APS System (20-yr levelized cents/kWh)*

	Orientation	Residential	Commercial
Benefits			
Direct Benefits	South	15.5	18.0
	West	21.8	23.4
	Average	18.7	20.7
Societal Benefits	All	9.3	7.5
Total Benefits	South	24.8	25.5
	West	31.1	30.9
	Average	28.0	28.2
Participant Costs			
Median		17.0	10.9
Range		12 to 24	9 to 14
Non-Participant Costs		17.9	11.2

The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

3. **Significant rate design changes for residential DG customers**, such as requiring solar DG customers to take service under the ECT-1R or ECT-2 TOU rates with demand charges, **would upset this balance**.

3. The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

4. The benefits of solar DG in APS's service territory are **higher for west-facing systems.** If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

1. Methodology

Solar DG is a long-term resource for the APS system. New solar DG systems will provide benefits for the APS service territory for the next 20 to 30 years. Thus, our analysis develops 20-year levelized benefits and costs for solar DG on the APS system. We evaluate the long-term benefits and costs of solar DG from multiple perspectives, using each of the major cost-effectiveness tests widely used in the utility industry.[4] Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 2** below ("+" denotes a benefit; "-" a cost).

Table 2: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	—		—
Customer Bill Savings or Utility Lost Revenues	+	—	
Benefits (Avoided Costs) -- Energy -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		—	—

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. First, the program should be a net benefit as a resource to the utility system or society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of solar DG systems to their benefits to the utility system and society as a whole. Second, the DG program will need to pass the Participant test if it is to attract customers to make long-term investments in DG systems. Finally, the Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties will benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

Data. The starting point for the data needed to perform full 20-year benefit/cost assessments is the utility's 2014 IRP, as a consistent set of long-term resource cost data that can be used to determine both the benefits and costs of solar DG. For example, we have used the natural

[4] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

gas forecast from the 2014 IRP, even though current gas prices are lower than was forecasted in 2014, and we have also used the long-term escalation in retail rates indicated by the 2014 IRP. If we were to update the natural gas forecast to use today's prices, we would also have to reduce correspondingly the long-term escalation in retail rates. We indicate in the report where we have supplemented 2014 IRP data with other information from discovery in this case, from prior DG studies in Arizona,5 and from other reports on the impacts of the growing demand for, and supply of, renewable generation in the western U.S.

Benefits. Several of the most important (and beneficial) characteristics of DG are the shorter lead times and smaller, scalable increments in which DG is deployed, compared to large-scale generation resources. In this respect, DG should be treated like energy efficiency (EE) and demand response (DR), which also are small-scale, short-lead-time resources. The DG included in APS's 2014 IRP combines with EE and DR to meet APS's resource needs in the near term and will help to defer the need for larger-scale resources in the long-run. The 2014 IRP finds that APS does not need new resources until 2017, and will not build new, large-scale, fossil resources until 2018. However, the 2014 IRP also shows continued growth both in energy efficiency and demand response programs and in distributed solar resources between 2014 and 2019, such that new demand-side resources developed in 2014-2019 will contribute 986 MW to meeting APS's peak demands by 2019.[6] As a result, solar DG, along with energy efficiency and demand response, contributes to deferring any new power plants until 2018, and solar DG installed before 2018 has greater value than just avoiding short-term energy costs.

We have included a number of additional benefits of DG that are often overlooked, including the following direct benefits that reduce ratepayer costs:

- **Fuel hedging benefits.** Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices.

- **Price mitigation benefits.** Solar DG reduces the demand both for electricity and for the gas used to produce the marginal kWh of power. These reductions have the broad benefit of lowering prices across the gas and electric markets in which APS operates.

- **Avoided capacity reserve costs.** When solar DG reduces peak demands on the APS system, it avoids not only generating capacity but also the associated 15% reserve margin. APS recognizes this avoided capacity reserve cost in calculating the benefits of peak demand reductions from other types of demand-side resources.[7]

In addition, solar DG also provides quantifiable societal benefits to the citizens in APS's service territory. These include important environmental benefits, such as reduced emissions of carbon and criteria air pollutants, and lower use of scarce water resources. The 2014 IRP includes the data needed to quantify the reduced emissions of these pollutants as well as the water savings. We draw upon several recent quantifications of these societal benefits. We also include the additional societal benefits of stimulating local economic activity and enabling customers to enhance the reliability and resiliency of their electric service.

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[5] For example, R.W. Beck (for APS), "Distributed Renewable Energy Operating Impacts and Valuation Study" (January 2009), hereafter, the "R.W. Beck Study," and SAIC Energy, Environmental and Infrastructure LLC (for APS), "2013 Updated Solar PV Value Report" (May 2013), hereafter, the "SAIC Study."

[6] 2014 IRP, at page 8 (Table 1) and 20.

[7] See APS response to TASC Data Request No. 2.1(j).

One of the reporting requirements of the 2014 IRP is a summary of the benefits of renewable generation on the APS system over the 2014-2028 IRP forecast period. These are shown below, from Table 27 of the 2014 IRP. We use APS's reported natural gas savings from renewables to estimate the avoided energy costs associated with solar DG, and we also use the avoided emissions from this conserved natural gas to quantify some of the environmental benefits associated with these clean energy resources.

TABLE 27 - RENEWABLE ENERGY BENEFITS

	TOTAL RENEWABLE			AVOIDED EMISSIONS						
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Metric Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	Water Usage (Acre Feet)
2014	701	3,182	23	1,280,869	7	162	146	40	6	3,066
2015	744	3,355	25	1,350,452	8	171	153	42	6	3,233
2016	775	3,492	26	1,405,597	8	178	160	43	7	3,365
2017	786	3,526	26	1,419,337	8	180	161	44	7	3,398
2018	798	3,566	26	1,435,664	8	182	163	44	7	3,437
2019	810	3,607	27	1,452,019	8	184	165	45	7	3,476
2020	863	3,934	29	1,583,558	9	200	180	49	7	3,791
2021	911	4,268	31	1,718,118	10	217	195	53	8	4,113
2022	960	4,656	34	1,874,185	10	237	213	58	9	4,486
2023	1,052	5,323	39	2,142,811	12	271	243	66	10	5,129
2024	1,095	5,706	42	2,296,957	13	291	261	71	11	5,498
2025	1,139	6,138	45	2,470,889	14	313	281	76	12	5,915
2026	1,157	6,230	46	2,507,865	14	317	285	77	12	6,003
2027	1,168	6,270	46	2,523,886	14	319	287	78	12	6,042
2028	1,256	6,915	51	2,783,504	15	352	316	86	13	6,663
2029	1,268	6,944	51	2,795,214	16	354	318	86	13	6,691
		TOTAL	567	31,040,924	173	3,927	3,527	959	145	74,305

Costs. The Participant Test uses the costs of solar DG for the participating customers who install solar systems. These are the costs for the systems themselves (offset by the federal investment tax credit), financing, maintenance, and periodic inverter replacement. The cost of DG systems can vary based on size, installation costs, financing terms, and output.

In the RIM Test, the costs of solar DG for non-participating ratepayers are principally the revenues which APS loses from customers serving their own load with DG. To these lost revenues we add an estimate of the solar integration costs which APS will incur to incorporate these resources into its system, as determined in APS's most recent solar integration study. We also add costs for the utility to interconnect DG customers and to administer the DG program.

The following sections discuss each of the benefits and costs of solar DG on the APS system. Solar DG is a long-term resource for the APS system with an expected useful life of at least 20 years. Accordingly, we calculate the benefits and costs of DG over a 20-year period in order to capture fully the value of these long-term resources, and we express the results as 20-year levelized costs using the same 7.2% per year discount rate that APS assumed in its 2014 IRP.[8]

[8] 2014 IRP, at Table 21 (APS' after-tax weighted average cost of capital).

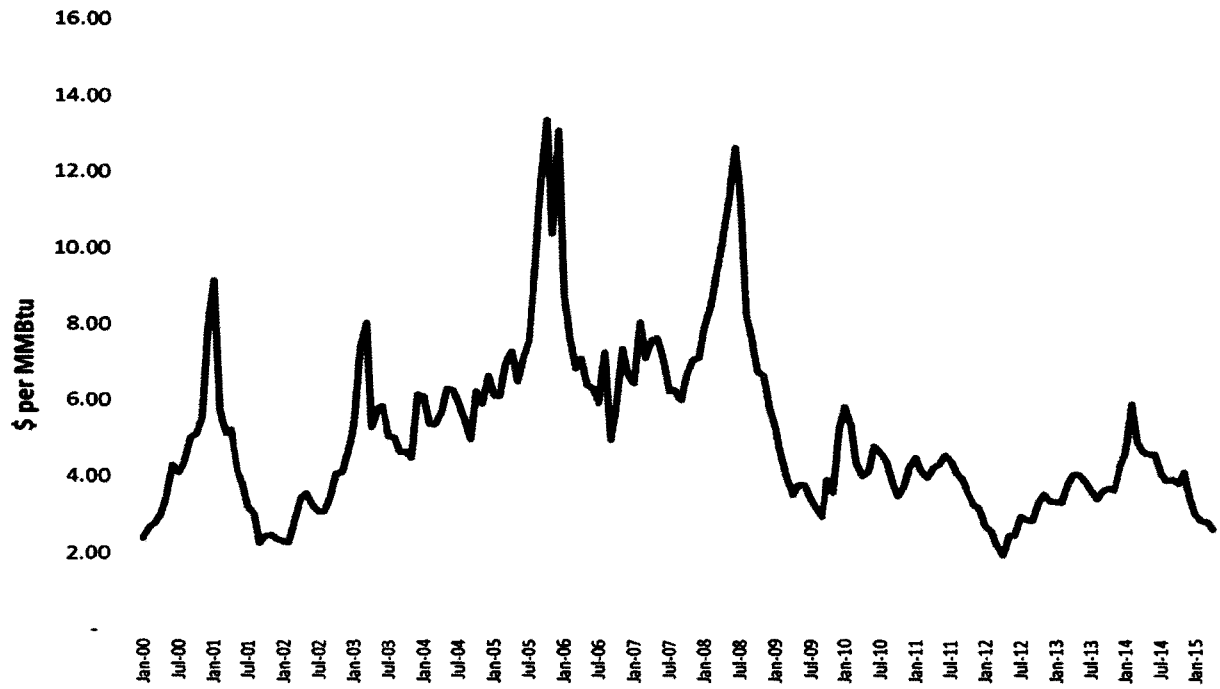
Table 3: *APS Avoided Energy Costs*

Avoided Energy Costs (20-year levelized c/kWh, 2016 $)	
Period	Avoided Costs
2016-2035	6.2

b. Fuel hedging costs

Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices, thus mitigating the impacts on ratepayers of periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 3** below.[14]

Figure 3: Henry Hub Natural Gas Market Prices



Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as is occurring today with the drought in California and long-term, drier-than-normal conditions elsewhere in the West. In 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output in the state due to the multi-year drought.[15] APS's 2012 IRP noted that, in both the intermediate- and long-terms, "renewable resources have the ability to diversify the overall portfolio of resources and provide mitigation against the inherent price volatility risks associated with a natural gas-dominated energy mix."[16]

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[14] Source for Figure 3: Chicago Mercantile Exchange data.

15 Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[16] 2012 IRP, at p. 64.

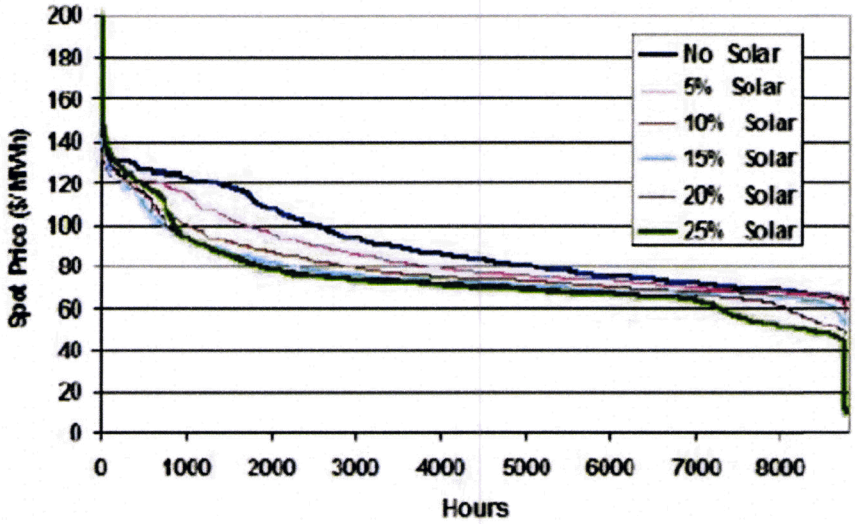

Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefits exist on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by Lawrence Berkeley National Lab (LBNL) has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[22] We have used an estimate at the low end of this range -- $10 per MWh – as the estimate for the long-term market price mitigation benefits from solar DG, on both gas and electric market prices. This represents about 20% of avoided energy costs (excluding avoided carbon) and is similar to the market price mitigation benefit that has been calculated in other U.S. energy markets.[23]

c. Generation Capacity

The 2014 IRP finds that APS does not need new large-scale, fossil resources until 2018.[24] However, the 2014 IRP shows continued growth in energy efficiency and demand response programs and in distributed solar resources between 2014 and 2018 (see Attachment F.1(a)(4)), such that the new customer-sited resources developed from 2014-2018 will contribute 862 MW to meeting APS's peak demands in 2018. Solar DG, along with energy efficiency and demand response, thus contribute to deferring any new power plants until 2018. As a result, solar DG installed before 2018 has greater value than just avoiding short-term energy costs. DG also hedges against events that could accelerate the 2018 need, such as unexpected increases in demand (from an accelerating economic recovery) or the loss of existing resources (for example, nuclear plant shutdowns such as occurred recently at the San Onofre plant in southern California).

Combustion turbines are the least-cost source of new utility-scale capacity. CTs are the

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[22] See Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL, January 2005), at p. ix, available at http://eetd.lbl.gov/EA/EMP.

[23] The market price mitigation benefit is also known as the "demand reduction induced price effect" (DRIPE), and has been quantified in several regions of the U.S. For example, in the New England ISO market, DRIPE is included as a standard component of the avoided costs of demand-side programs and has been estimated at as much as 35-36% of summer peak energy prices. See Synapse Energy Economics, "Avoided Energy Supply Costs in New England: 2013 Report" (July 12, 2013), at page 1-6, Exhibit 1-2. Available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf.

[24] 2014 IRP, at p. xvi.

long-term peaking resource typically displaced by solar DG, and are the resource that APS expects to add in 2018.[25] Based on the capital and fixed O&M cost for the type of smaller, 100 MW CTs that APS plans to add at the Ocotillo site by 2018,[26] we calculate that APS's levelized avoided generation capacity costs are $212 per kW-year in 2016 dollars, as shown in **Table 4**.

The CT fixed costs are multiplied by the capacity value of distributed PV, as a percentage of its nameplate capacity. The 2014 IRP reports the capacity value of residential PV to be 45% of nameplate capacity.[27] We have done our own calculation of the capacity value of distributed PV, based on solar output in those high-demand hours with loads within one standard deviation of the annual peak hour, using the hourly IRP load forecasts for 2016-2017 that APS provided in discovery. These high-demand hours are weighted by the amount by which the load in each hour exceeds the threshold of one standard deviation below the peak. The use of such a set of "peak capacity allocation factors" is a standard method for determining the contribution of a load or resource to the system peak.[28] As shown in Table 4, the capacity value of south-facing solar PV in 2016-2017 is 36% of nameplate, but this increases significantly, to 53% of nameplate, for west-facing systems that produce more energy in the high load hours of late summer afternoons.

Table 4: *Avoided Generation Capacity Costs ($ per kW-year in 2016$)*

Component	**Value**	*Notes / Sources*
CT Capital Cost	1,493	*$ per kW. 2014 IRP, Attachment D.3, for 100 MW brownfield CTs. Escalated to 2016$ at 2% per year inflation.*
x 11.17% carrying charge	166.8	*$ per kW-yr. SAIC Study, Table 3-2*
+ Fixed O&M	17.9	*$ per kW-yr. 2014 IRP, Attachment D.3*
= Total	184.7	*$ per kW-yr. 20-year levelized value*
+ Capacity reserve	15%	*APS reserve margin*
= Total with reserves	212.4	*$ per kW-yr*
x PV Capacity Value	36.2%	*South-facing, Phoenix*
x PV Capacity Value	53.2%	*West-facing, Phoenix*
+ Capacity losses	11.7%	*SAIC Study, at p. 2-9* RWB
÷ PV Output[29]	1,730	*kWh/kW. South-facing, Phoenix*
÷ PV Output	1,490	*kWh/kW. West-facing, Phoenix*
Avoided Costs		
Fixed array – South-facing	5.0 cents/kWh	
Fixed array – West-facing	8.9 cents/kWh	

[25] The Beck and SAIC Studies also used the fixed costs of a new CT to calculate solar DG's generation capacity value.

[26] 2014 IRP, at p. xiv.

[27] *Ibid.*, at Attachment D.3.

[28] For example, a similar PCAF approach has been used in the California Public Tool model referenced in Footnote 2 above, to determine the marginal transmission and distribution costs avoided by net-metered solar DG. Our approach values solar DG using its capacity factor in a select set of high-value hours. Thus, our method is a version of the "Capacity Factor" methods for determining the capacity value of solar. A 2012 study from NREL found that such methods can accurately approximate the results of more complex, but also more opaque and difficult-to-replicate, methods such as effective load carrying capacity (ELCC) models that APS appears to use. See Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, "Comparison of Capacity Value Methods for Photovoltaics in the Western United States" (NREL, July 2012), available at http://www.nrel.gov/docs/fy12osti/54704.pdf.

[29] Using NREL's PVWATTS calculator.

This analysis focuses on the value of solar to be developed in the near future (2016-2017). APS argues in the 2014 IRP that, as solar DG penetration increases, the capacity value of solar PV will decrease, as the increased amounts of behind-the-meter solar resources shift APS's afternoon peak to later in the day. This possibility does not diminish the capacity value of solar installed today; indeed, the decline in capacity value in the future will not occur unless substantial amounts of solar are installed over the next twelve years. Further, the conclusion that the capacity value of solar will decline over time assumes that the future will look like today, only with more solar. This may not be true. For example, other trends, such as hotter summers resulting from climate change, could increase future peak demands by more than expected, and offset the impact of solar additions. Customers also can respond to the changing mix of resources, for example, by installing west-facing PV systems if properly incentivized to do so. Or if additional solar reduces the price for grid power in the early-to-mid afternoon, if those prices are conveyed in accurate price signals, and if customers have greater choice and control over when and from where they consume electricity, consumers will respond by shifting consumption from the evening to the afternoon – i.e. the opposite of what DR tries to achieve today – pre-cooling homes, running appliances remotely, and filling batteries in the afternoon instead of the evening.

d. Transmission

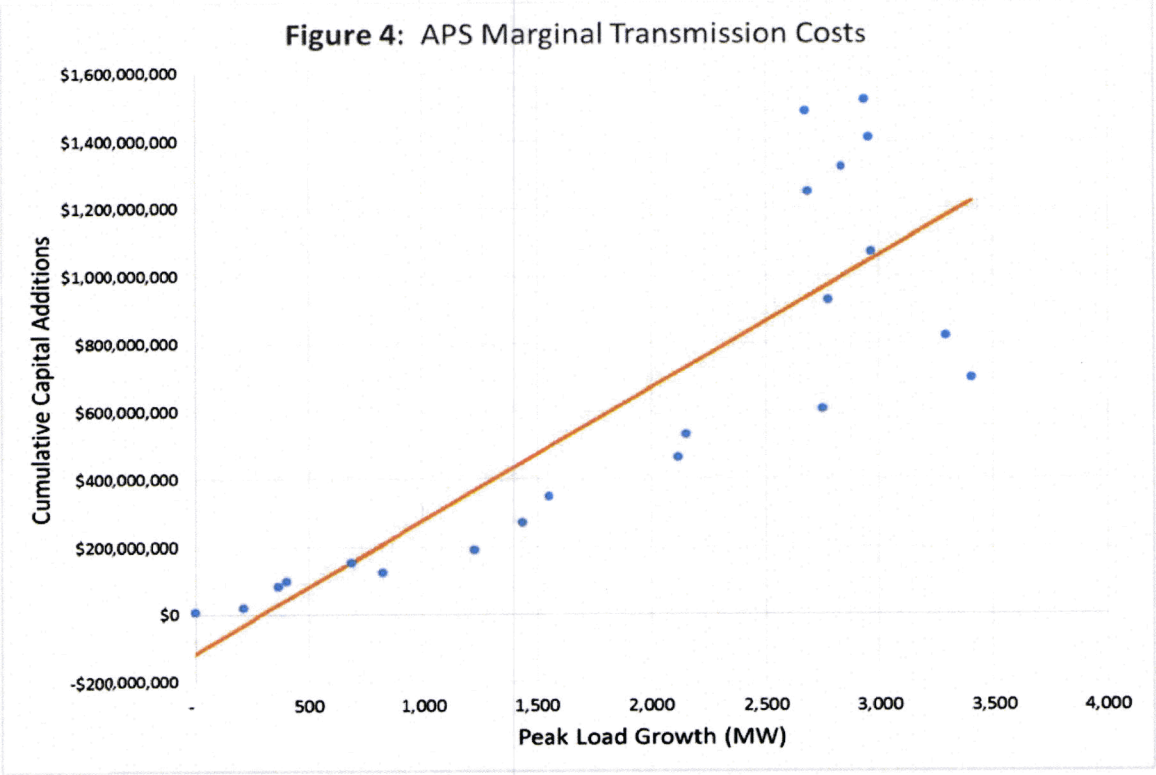
The output of solar distributed generation (DG) primarily serves on-site loads and never touches the grid, and thus clearly reduces loads on the transmission grid. Even for the minority of power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors. Thus, much like energy-efficiency and demand response resources, solar DG displaces traditional generation sources must use the utility transmission system to be delivered to customers.

Solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods. Like energy efficiency and demand response resources, solar DG helps the utility to manage and to reduce load growth, thus avoiding and deferring the need for load-related transmission investments. This benefit is measured by the utility's marginal cost of load-related transmission capacity.

A well-accepted way to estimate long-term marginal transmission capacity costs is the industry-standard National Economic Research Associates (NERA) regression method, which is used by many utilities to determine their marginal transmission capacity costs that vary with changes in load. The NERA regression model fits incremental transmission costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and load growth.

The APS 2014 IRP indicates that transmission costs for projects included in its 10-year transmission plan have been excluded from the forecast expenditures in its IRP.[30] Lacking a basis for including a five-year forecast of future expenditures and load growth, we have utilized a NERA regression based on historical peak load growth and transmission expenditures, over a 20-year period from 1995 to 2014. Crossborder's analysis of marginal transmission costs uses APS's FERC Form 1 data for this period. **Figure 4** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the APS system.

[30] The APS 10-year transmission plan only reports total costs over the entire period, not costs on an annual basis.



The regression slope resulting from this analysis is $392 per kW. We convert this to an annualized marginal transmission costs using a carrying charge of 11.05%. The resulting avoided cost for transmission capacity for APS is $43 per kW-year. For comparison, APS's current FERC-authorized long-term firm transmission rate is $36.13 per kW-year.[31] Although this FERC rate is an embedded, not a marginal, cost number, it does represent APS's opportunity cost to sell firm transmission capacity which is made available by reduced load growth resulting from DG and other demand-side resources.

The next step is to convert a portion of this marginal transmission capacity value to an equivalent energy price that considers the extent to which solar DG avoids investments in marginal transmission capacity. Transmission system peaks typically coincide with system demand peaks, and thus we have assumed that the contribution of solar DG to reducing transmission system peaks is the same as its contribution to avoiding the demand for generating capacity. We assume a 36% contribution to peak for south-facing systems and a 53% contribution for west-facing solar DG to estimate the contribution of solar DG to avoiding transmission costs. The result is a solar DG value for transmission capacity equal to about $14 per kW-year for south-facing systems (i.e. $37 per kW-year x 39% contribution to peak) and $19 per kW-year for west-facing. We then convert these solar DG avoided transmission capacity cost to dollars per MWh of solar DG output, assuming the same average annual outputs listed in Table 4. **Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $8 per MWh (0.8 cents per kWh) for south-facing systems and $13 per MWh (1.3 cents per kWh) for west-facing systems.

[31] See http://www.oasis.oati.com/AZPS/AZPSdocs/6-1-2015_Effective_Formula_Rates.pdf.

Table 5: *APS Marginal Transmission Cost*

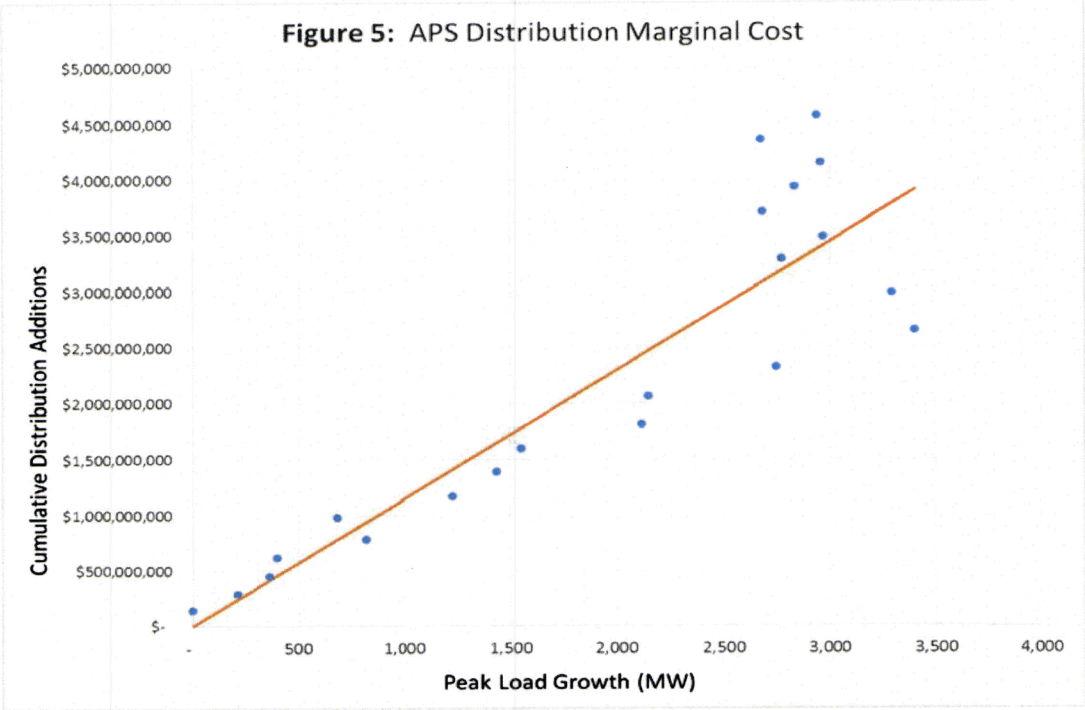
Component	Cost or Metric	*Notes*
Marginal load-related Transmission Cost	392	*$ per kW*
x Carrying Cost @ 11.05%	11.05%	*SAIC Study, Table 3-2*
= Marginal Transmission Capacity Cost	43.3	*$ per kW-year*
x Solar Capacity as % of Nameplate	36.2%	*South-facing, Phoenix*
	53.2%	*West-facing, Phoenix*
= Transmission Capacity Costs Avoided	15.7	*South, $ per kW-year*
	23.0	*West, $ per kW-year*
÷ Annual PV Output kWh per kW-AC	1,730	*South, kWh per kW-AC*
	1,420	*West, kWh per kW-AC*
= Avoided Transmission Capacity Cost	0.9	*South, cents per kWh*
	1.6	*West, cents per kWh*

e. Distribution

The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission, for various reasons. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of the avoided distribution costs that result from solar DG reducing distribution system loads. It is clear, however, that the majority of solar DG output which serves the on-site load will reduce distribution loads, because that power will never flow onto the distribution system and will reduce loads served from the grid. Further, exports from solar DG to the distribution system can serve local loads, and thus unload upstream portions of the distribution system. As a result, we expect that solar DG will reduce distribution system loads, particularly at the relatively modest penetrations of DG on most distribution circuits in Arizona today, thus avoiding the cost of distribution system expansions or upgrades, and extending the life of existing equipment.

As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed can be challenging to predict or to manage.

We have applied a linear regression analysis to APS's distribution capital additions and peak system load growth, analogous to the transmission marginal cost analysis presented above. The results of this analysis are shown in **Figure 4**. Converting the regression slope of $1,149 per kW to an annual cost using a carrying charge of 11.05% results in an annualized marginal distribution cost of $127 per kW-year. We note that this regression analysis considers only the historical relationship between distribution capital additions and load growth. Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, this estimate of avoided distribution costs should be considered conservative.



We adopt an additional refinement in calculating the effective capacity value of solar DG at the distribution level. We calculate the solar capacity value separately for residential and commercial customers, using separate hourly load data for residential and commercial (Schedule GS) customers. This reflects the fact that a distribution circuit serving residential customers, for example, will reflect the characteristics of this type of customer. As the table below shows, the effective capacity value of solar is significantly lower on a residential circuit (20% for south-facing) than on a circuit serving commercial loads (55% for south-facing). This is because residential loads peak in the late afternoon and early evening, while commercial loads peak earlier in the afternoon when solar output is higher. **Table 6** shows the resulting marginal distribution capacity costs, for residential and commercial customers and for south- and west-facing systems.

Table 6: *APS Marginal Distribution Capacity Cost*

Component	Residential	Commercial	
Marginal load-related Distribution Cost	1,149	1,149	*$ per kW*
x Carrying Cost	11.05%	11.05%	*SAIC Study, Table 3-2.*
= Marginal Distribution Capacity Cost	127.0	127.0	*$ per kW-year*
x Solar Capacity as % of Nameplate	20.1%	55.0%	*South-facing, Phoenix*
	36.0%	53.3%	*West-facing, Phoenix*
= Distribution Capacity Costs Avoided	25.6	69.8	*South, $ per kW-year*
	45.7	67.6	*West, $ per kW-year*
÷ Annual PV Output	1,728	1,728	*South, kWh per kW-AC*
	1,492	1,492	*West, kWh per kW-AC*
= Avoided Distribution Capacity Costs	1.5	4.0	*South, cents per kWh*
	3.2	4.8	*West, cents per kWh*

3. Societal Benefits of Solar DG

Renewable DG has benefits to society that do not directly impact utility rates. When renewable generation takes the place of conventional fossil fuel generation, all citizens benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demand on existing water supplies is reduced, avoiding the potential need to acquire new sources of supply. Distributed generation in particular, by siting energy generation in the built environment, results in more land being available for other uses, or as natural habitat. Distributed generation makes the power system more resilient, and stimulates the local economy. Each of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 3% in calculating these benefits, rather than the 7.2% APS discount rate used for the direct benefits.

a. Carbon

The social cost of carbon (SCC) is "a measure of the seriousness of climate change."[32] It is a way of conceptualizing the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the avoided energy costs discussed above are limited to market-based cap and trade permit compliance costs, which are much lower than the true cost that carbon pollution imposes on society.

The most prominent and reputable source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[33] 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 scenarios.[34] 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 7: *Social Cost of Carbon*[35] *(2007 $ per metric tonne of CO2)*

	Discount Rate		
	5%	3%	2.5%
Social Cost of Carbon	11	36	56

We recommend a base case SCC using the mid value of $36 per tonne. We escalate these benefits by 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."[36]

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[32] 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.

[33] 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.

[34] *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.

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

[36] *Id,* pp. 13-14. 5% annual escalation in carbon costs was also used in the California Public Tool. See the CPUC Final Public Tool referenced in Footnote 2 above, at tab "Key Driver Inputs," at Cell D33. It is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in the 2014 APS IRP.

While estimating the social cost of carbon contains many inherent uncertainties, we believe these values are defensible. Despite the unknowns, federal government agencies are required to use these figures in cost-benefit analysis. The mid-range real discount rate of 3% is a typical societal discount rate often used in long-term benefit/cost analyses. 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.[37] 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."[38]

We calculate the societal benefits of reducing carbon emissions as the SCC less the "market" carbon costs used in the direct benefits, discussed above. In addition, we also include in the total CO_2 emissions for APS the additional methane emissions that will occur from leakage in the natural gas infrastructure that serves APS's gas-fired power plants. We attach to this report as **Attachment 1** a recent white paper calculating the additional GHG emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the gas infrastructure that serves gas-fired electric generation.

b. Health Benefits of Reducing Criteria Air Pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[39] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[40]

We recommend using the health co-benefits from reductions in criteria pollutants that were developed by the EPA in conjunction with the Clean Power Plan. These benefit estimates are recent, as they were developed in 2014 as part of the technical analysis for the proposed rule.

Particulates (PM-2.5). PM-2.5 are the particulate emissions with the most adverse impacts on health. To calculate the avoided PM-2.5 emissions from renewable DG on the APS system, we assume an emissions factor of 0.0077 lbs/MMBtu for PM-2.5 emissions from the combustion of natural gas. This factor is from "AP 42," the EPA's compilation of air pollutant emissions factors.[41] This reference states that the "PM emission factors presented here may be

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[37] California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

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

[39] 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.

[40] *Ibid.*

[41] U.S. EPA, "Emissions Factors & AP 42, *Compilation of Air Pollutant Emission Factors*," http://www.epa.gov/ttn/chief/ap42/index.html.

used to estimate PM10, PM2.5 or PM1 emissions."[42] We use the PM-2.5 emissions factor and damage costs, because PM-2.5 are the small particulates with the most adverse impacts on health.

The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[43] The EPA estimates that approximately 80% of primary PM-2.5 emitted in Arizona is crustal material, with the bulk of the remainder being elemental or organic carbon.[44] The emissions factor of 0.0077 lbs/MMBtu for total primary PM-2.5 does not differentiate among particle types.[45] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Arizona emissions. The health benefits of reducing PM-2.5 emissions are $115 per short ton.

For elemental and organic carbon:

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

For crustal particulate matter:

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

Total:

$$(\$225.25 \times 0.2) + (\$87.45 \times 0.8) = \$115.01\ per\ lb\ PM$$

Nitrous oxides (NO_x). Heath damages from exposure to nitrous oxides 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.[46] The EPA calculates health benefits of avoiding formation of either of these pollutants: $7,400 to $31,000 for ozone formation, and $17,000 to $34,000 for PM-2.5 formation, both in 2011$. We include both types of avoided health costs in our calculations, and use the mid-points of EPA's ranges of health benefits -- $24 per ton.

$$\frac{44{,}700\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$23.69\ per\ lb$$

c. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand.

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[42] 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").

[43] CPP Technical Analysis, p. 4-17.

[44] *Ibid.*, p. 4A-8, Figure 4A-5.

[45] AP 42, Table 1.4-2, Footnote (c).

[46] CPP Technical Analysis, p. 4-14.

The APS 2012 IRP cited a water cost of $1,114 per acre-foot.[47] Two recent California studies also have quantified the additional cost of retrofitting existing natural gas plants to reduce their water consumption, or of developing other water supplies to replace water consumed in power generation. A California Energy Commission (CEC) study calculated the "effective cost" of water use at a natural gas plant, or "the additional cost of using dry cooling expressed on an annualized basis divided by the annual reduction in water requirement achieved through the use of dry cooling."[48] In other words, if the water supply in the region with the power plant is or becomes constrained, what would it cost (in terms of the direct cost as well as the cost of lost generation efficiency) to convert the plant to run on dry cooling? The CEC found that the effective cost of saved water using this metric ranges from $3.40 to $6.00 per 1,000 gallons, or $1,110 to $1,955 per acre-foot with a mid-point of $1,530 per acre-foot.[49] Similarly, a recent study by the consulting firm Energy and Environmental Economics calculated the avoided cost of water in California based on the cost of the embedded energy in water and the avoided costs to develop new water supplies.[50] They find an avoided cost of water ranging from $442 (imported groundwater) to $1,093 (treated wastewater) to $2,349 (desalinated water) per acre foot. We eliminate the option of importing groundwater as infeasible, since the crisis of dwindling and over-used groundwater in the West is well-known.[51] The remaining three estimates are roughly consistent, and average to $1,660 per acre-foot, which is the value we have used to quantify the water savings from renewable DG, based on the quantity of water savings from renewable generation that APS stated in Table 27 of the 2014 IRP.

d. Local economic benefits

Distributed generation has higher costs per kW than central station renewable or gas-fired generation. However, a portion of the higher costs – 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 close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing such costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following tables present recent data, from detailed surveys of solar installers conducted by two national labs (LBNL and NREL), on the soft costs that are likely to be spent in the local area where the DG customer resides.

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[47] 2012 IRP, at pp. 135-136.

[48] California Energy Commission, *Cost and Value of Water at Combined Cycle Power Plants.* CEC-500-2006-034 (April 2006), p. 4. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF.

[49] *Ibid.* at p. 4; Wind Vision at p. 201.

[50] Cutter, Eric, Ben Haley, Jim Williams and C.K. Woo, "Cost-effective Water-Energy Nexus: A California Case Study." The Electricity Journal, 27 (5), July 2014. Available at https://ethree.com/documents/E3_Energy_Water_EJ_web.pdf.

[51] *See, e.g.*, Justin Gillis and Matt Richtel, "Beneath California Crops, Groundwater Crisis Grows." *The New York Times* (April 5, 2015). http://www.nytimes.com/2015/04/06/science/beneath-california-crops-groundwater-crisis-grows.html?_r=0.

Table 8: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[52]		NREL – B. Friedman *et al.*[53]	
	$/watt	%	$/watt	%
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Table 9: *Commercial Local Soft Costs*

Local Costs	NREL – B. Friedman *et al.*			
	Small Commercial		Large Commercial	
	$/watt	%	$/watt	%
Total System Cost	4.97	100%	4.05	100%
Local Soft Costs				
Customer acquisition & marketing	0.13	3%	0.03	1%
Installation labor	0.39	8%	0.17	5%
Permitting & interconnection	0.01	0.2%	0.00	0%
Permit fees	0.07	1%	0.04	1%
Total local soft costs	**0.60**	**12%**	**0.24**	**6%**

These economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of 4.7 cents per kWh of DG output for residential and 2.9 cents per kWh for commercial, or an average of 4.2 cents per kWh assuming 74% residential systems, 26% commercial.

Table 10: *Societal Benefits (20-yr levelized cents per kWh)*

Benefit	Value
Social cost of carbon – reduced damages	3.3
Health benefits – lower PM-2.5 and NOx emissions	1.0
Water benefits – increased water availability	0.2
Local economic benefit	4.2
Total Societal Benefits	8.7

4. Total Benefits

The following **Table 11** summarizes the direct and societal benefits of solar DG for both residential and commercial installations.

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[52] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37 ,

[53] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

Table 11: *Summary of Solar DG Benefits for APS (20-year levelized cents/kWh)*

Avoided Cost	Orientation	Residential	Commercial
Direct			
Energy	All	6.2	6.2
Fuel price hedging	All	0.9	0.9
Market price mitigation	All	1.0	1.0
Capacity	South	5.0	5.0
	West	8.9	8.9
Transmission	South	0.9	0.9
	West	1.6	1.6
Distribution	South	1.5	4.0
	West	3.2	4.8
Total Direct Benefits	South	15.5	18.0
	West	21.8	23.4
	Average	18.7	20.7
Societal			
Carbon	All	3.3	3.3
Criteria Pollutants	All	1.1	1.1
Water	All	0.2	0.2
Local economic benefit	All	4.7	2.9
Total Societal Benefits	All	9.3	7.5
Total Benefits			
Direct and Societal	South	24.8	25.5
	West	31.1	30.9
	Average	28.0	28.2

5. Costs of Solar DG for Participants

We have used a pro forma cash flow analysis to project the lifecycle cost of a solar DG system based on 2014 solar system costs in Arizona surveyed and reported by LBNL in their annual *Tracking the Sun* report. The median of these costs ($3.70 per watt DC) is similar to the $3.87 per watt reported by APS in Attachment D.3 of the 2014 IRP. We also used the assumptions summarized in **Table 12**.

Table 12: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$3.70 per watt DC
Range of Costs	$2.80 - $5.00 per watt DC
Federal ITC	30%
Financing Cost	5%
Participant discount rate	7.2%
Financing Term	15 years
Inverter Replacement	$700/kW in Year 15
Maintenance Cost	$26 per kW-year

The assumptions for the costs of commercial systems are similar, with the addition that commercial systems qualify for accelerated depreciation. **Table 1** shows the resulting levelized cost of solar for residential and commercial customers.

6. Costs of Solar DG for Non-participating Ratepayers

The primary costs of solar DG for non-participating ratepayers are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load. For residential customers, the retail rate credits amount to 14.6 cents per kWh; for business customers, the credits are 8.8 cents per kWh. Based on the system average rates in the 2014 IRP, plus increases at inflation for the delivery component of APS's rates, the expected rate escalation from 2016-2035 is 2.8% per year. This escalation assumption plus a 7.2% discount rate produce 20-year levelized retail rate credits of 17.4 cents per kWh for residential and 11.2 cents per kWh for commercial (2016 $). Assuming the mix of residential and commercial systems installed in 2014 (76% residential and 26% commercial),[54] the average levelized rate credit is 16.2 cents per kWh.

Next, we add an estimate of solar integration costs using a 2012 study which APS commissioned which estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[55] We assume that these costs scale to other years as a function of gas costs. Finally, we add 0.3 cents per kWh for the levelized cost of utility administration of the DG program, from the detailed data on such costs that was assembled last year for the California Public Tool model referenced above.

Table 13 summarizes these costs of DG for APS's non-participating ratepayers.

Table 13: *Non-participant Costs of Residential and Commercial Solar DG*

Cost categories	Costs (20-year levelized cents per kWh)		
	Residential	Commercial	Average
Distribution of systems	*74%*	*26%*	*100%*
Lost retail rate revenues	17.4	10.7	15.7
DG incentives	n/a	n/a	n/a
Integration costs	0.2	0.2	0.2
Program administration	0.3	0.3	0.3
Total Costs	**17.9**	**11.2**	**16.2**

Among the significant results of this analysis is that the lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates would improve the cost-effectiveness of solar DG. However, the lost revenues (or, for solar customers, the bill savings) under the APS residential TOU rates with demand charges (Schedules ECT-1R and ECT-2) are just 10 - 14 cents per kWh, which are significantly below the residential cost of solar.

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[54] From APS's 2014 RES Compliance Report (April 1, 2015), at p. 4.

[55] See 2014 IRP, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

7. Key Conclusions of this Benefit/Cost Analysis

This analysis of solar DG as a resource for APS has considered cost-effectiveness from multiple perspectives. Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing distributed generation.

The principal conclusions of our analysis are as follows:

1. Solar DG is a cost-effective resource for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a rough balance between the costs and benefits of residential DG for both participants and non-participants, as shown by the Participant and Ratepayer Impact Measure test results.

3. Significant rate design changes for residential DG customers, such as requiring solar DG customers to take service under the ECT-2 rate with demand charges, would upset this balance.

3. The benefits of DG significantly exceed the costs in the commercial market. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

4. The benefits of solar DG in APS's service territory are higher for west-facing systems. If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

Attachment 1

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

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February 19, 2016

1. Summary

Natural gas has been commonly depicted as a "bridge" fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency's (EPA) "Inventory of U.S. Greenhouse Gas Emissions and Sinks" attempts to calculate methane emissions from natural gas systems using a "Bottom Up" accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2 Eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the CO2 emission factor for burning natural gas in power plants to include the CO2 equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas, leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks,"

adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO2 emitted by burning methane to 175.5 lbs of CO2 Eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU

measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emission were 1.9 (1.5 – 2.4) times the number reported the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34.[9] The previous value (based on the 2007 IPCC AR4) is 25. Policy makers continue to tend to use the values closer to 25.[9] For example, the EPA uses 25 in its "Inventory of U.S. Greenhouse Gas Emissions and Sinks," but 34 is more commonly used in the scientific literature.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 175.5 lbs of CO2 per MMBtu of natural gas burned, assuming a conservative GWP of 25.

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EXHIBIT
TASC 27
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

REBUTTAL TESTIMONY OF R. THOMAS BEACH

Executive Summary

This rebuttal testimony responds to the opening testimony of the other parties to this proceeding on the benefits and cost of renewable distributed generation (DG) resources in Arizona.

My direct testimony for TASC proposed a benefit-cost methodology for valuing DG resources that builds upon the widely-used, industry-standard approach to assessing the cost-effectiveness of other types of both demand- and supply-side resources. When applied to DG resources, these analyses assess the benefits and costs of DG from multiple perspectives, including those of the principal stakeholders in DG development, including (1) participating customer-generators, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in developing renewable DG technologies.

This rebuttal testimony responds to the testimony of the utilities who advocate the use of cost of service studies (COSS) or market prices to assess the cost-effectiveness of renewable DG. COSS are based on utility costs in only a single test year, and thus fail the capture the full benefits and costs of renewable DG over the long-term life of these resources. A COSS is likely to underestimate the long-run costs avoided by renewable DG, particularly avoided capacity costs for generation, transmission, and distribution. COSS are not used to judge the cost-effectiveness of other types of resources, such as utility-owned resources. Although market prices (where they exist) are useful for assessing portions of the benefits of DG, they do not cover all of the benefits; in particular, they do not cover the avoided costs for transmission and distribution capacity. Further, markets are only beginning to be used to value important externalities such as environmental costs.

This rebuttal testimony observes that the parties to this case agree on many of the benefits and costs of renewable DG. I discuss several benefits on which there is not agreement: fuel hedging and market price mitigation. A primary objection is that the amount of DG output is not sufficient to produce such benefits. This argument is belied by the current penetration of DG resources in Arizona today (3% and growing) as well as by the utilities' recognition that customer-sited resources – including energy efficiency and demand response as well as DG – are now a significant resource on which they are relying to meet future resource needs. Further, this growing industry promises to provide broad economic benefits for the state of Arizona, particularly if businesses in Arizona leverage the state's leadership position, abundant solar resources, and local expertise to serve markets for distributed renewable resources outside of Arizona.

Finally, this rebuttal responds to the testimony of the Residential Utility Consumer Office (RUCO). RUCO argues that, in assessing the benefits and costs of renewable DG, the perspective of non-participating ratepayers should be emphasized. My testimony argues that the Commission should prioritize the Societal Test, which is also the test used to evaluate the cost-effectiveness of other demand-side programs in Arizona. RUCO's preference for the Ratepayer Impact Measure (RIM) Test is not justified by the differences between DG and other types of demand-side resources. Upon closer inspection, these differences are not significant enough to warrant the use of a different test. Moreover, if the Commission shares RUCO's concern that only a subset of ratepayers have access to DG technologies, the Commission should take note that middle-income ratepayers now are the most common solar adopters. In addition, there are model programs in other states that are extending the availability of solar to renters, homeowners with shaded roofs, and low-income customers. Instead of favoring non-participating ratepayers, the Commission should look equally at the perspectives of both participating and non-participating ratepayers, and should seek to balance these viewpoints in order to best serve the public interest of all ratepayers.

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I. INTRODUCTION / 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: Have you previously submitted direct testimony in this docket?

A2: Yes, I have. On February 27, 2016, I submitted direct testimony in this docket on behalf of The Alliance for Solar Choice ("TASC"). My experience and qualifications are described in my *curriculum vitae*, which is attached to my direct testimony as **Exhibit 1**.

II. PURPOSE

Q3: What is the purpose of this rebuttal testimony?

A3: My direct testimony presented TASC's proposal for how the Commission should establish the long-term value of distributed generation (DG) in Arizona, through an analysis of the benefits and costs of DG technologies. My testimony also addressed how the results of this cost-effectiveness methodology should inform the Commission's further consideration of the rates that apply to DG customers, or of future changes to the structure of net energy metering (NEM) in Arizona. This rebuttal testimony will not repeat that proposal in detail. Instead, this rebuttal focuses on responding to the proposals of other parties, including the Utilities Division Staff (Staff), the Residential Utility Consumer Office (RUCO), Arizona Public Service (APS), and Tucson Electric Power Company and UNS Electric, Inc. (TEP). I also provide responses to the questions that several commissioners have posed in this proceeding; these responses draw upon both my opening testimony and this rebuttal.

Q4: How is your rebuttal testimony organized?

A4: My opening testimony discussed four key attributes of a methodology to assess the benefits and costs of net metered DG resources.

1. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.

2. **Focus on NEM exports.** The retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption.

3. **Consider a comprehensive list of benefits and costs.** DG resources are different than utility-scale, central station resources in their location, diversity, and technologies. As a result, DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA.

4. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility.

This rebuttal is organized with sections on each of these attributes, and I review the extent to which the proposals of the other parties also share these attributes. I first discuss the broad issue of the role of benefit/cost studies in the Commission's regulation of DG resources. This issue is directly related to the first two attributes of DG – they are long-term resources that export power to the electric grid. I then discuss the differences between the parties on the specific benefits and costs of DG, and conclude with observations on why the Commission should take care to balance the perspectives of all stakeholders in Arizona's growing DG resources – participating ratepayers, non-participating ratepayers, the utility, and the state as a whole. This rebuttal concludes with the responses to the commissioners' questions.

III. THE REGULATORY CONTEXT FOR DISTRIBUTED GENERATION BENEFIT/COST STUDIES – DG IS A LONG-TERM RESOURCE, AND MUST BE EVALUATED AS SUCH.

Q5: Several witnesses, notably Mr. Brown for APS, argue that the Commission should not consider, or should place less weight on, long-term benefit / cost analyses in deciding the regulatory treatment of DG in Arizona. Please provide some context for why the Commission should consider such studies, and why they are essential.

A5: Renewable distributed generation – solar, wind, biomass, small hydro – are long-term generation resources that will have useful lives of 20-30 years producing clean, renewable electricity. If the utility were proposing to build and operate these distributed resources (or any other new resource, of any size), it would apply to this Commission to place them into its rate base, and would have to show, in a rate case, certification proceeding, and integrated resource plan, why the long-term benefits of these new resources exceeded their long-term costs, so that ratepayers in Arizona would benefit from their construction and operation over the resources' useful lives. The utility's showing of the benefits of these new resources undoubtedly would include many of the same long-term benefits of DG that the parties to this case have presented. These benefits would focus on the future costs that the utility would avoid through the construction of the new resources: avoided energy costs, avoided generation capacity, lower line losses, reduced T&D costs, lower emissions of pollutants, other environmental benefits, and reduced costs to comply with RPS requirements. Utilities even include difficult-to-quantify economic benefits in justifying new resources.[1] The cost of the new resources would be the present worth of the utility revenue requirement over their useful lives. This showing of the cost effectiveness of new resources is essentially a showing that the resources pass the Total Resource Cost (TRC) and Societal Tests discussed in my direct testimony. Such a showing of the long-term benefits and costs of new resources is standard practice for state regulators in the U.S., for both supply- and demand-side

[1] Vote Solar's Ms. Kobor notes the long-term rate stability benefits that TEP has cited to justify its acquisition of a combined-cycle plant. Vote Solar Kobor, at pp. 10-11.

resources, and is an essential process that enables a state commission to find that new resources are just and reasonable for recovery through the utility's rate base.

It is interesting that Mr. Brown's copious scorn for cost-effectiveness analyses of DG resources is not shared by the other witnesses for APS. Mr. Albert, who actually does resource management for APS, testifies that:

> ... a Value of Solar (VOS) calculation can play a valuable role for policy makers. The VOS can inform resource planning decisions and can be used to evaluate and even establish how rooftop solar is incentivized. For example, the Commission can consider the VOS in determining the amount paid to customers who export energy to the grid from their rooftop solar systems. The Commission could also use the VOS to establish additional transparent incentives, such as the up-front cash incentive that the Commission authorized for a period of time.[2]

Mr. Sterling for APS provides testimony discussing a collaborative process that the Tennessee Valley Authority (TVA) undertook in 2014-2015 with a broad range of stakeholders to establish the value (the benefits net of the costs) of distributed resources in TVA's service territory. His testimony documents the substantial, but not complete, consensus that this process achieved.

Q6: What is different about renewable DG resources, compared to utility-owned generation?

A6: The difference is that, with renewable DG, it is customers, not the utility, who are making the long-term investment in these new resources. Renewable DG serves a portion of the loads of the customers who install it, displacing purchases from the utility. The remaining DG output is exported to the utility where it serves neighboring customers, also displacing generation from the utility system. Renewable DG represents customers exercising a competitive choice to purchase, in part, a product different from what the utility offers. Because today's utility business model ties earnings directly to the utility's rate base, the choice of DG will reduce the utility's future profits to the extent that, with

[2] APS Albert, at p. 2.

customer-sited DG on its system, the utility will add less rate base to serve a lower demand for its power.

Q7: How does this financial interest impact a utility's perspective on a long-term cost effectiveness analysis of new DG resources?

A7: A utility whose future financial returns are threatened by renewable DG faces a conflict of interest in presenting a balanced view of the long-term benefits and costs of DG resources.

Q8: Would a utility with such a conflict of interest be more likely to support setting rates for DG customers based on an embedded cost-of-service study (COSS)?

A8: Yes. A COSS is based on a single "test year" snapshot of the utility's costs, either a recent historical year (as in Arizona) or a near-future test year (as in other states such as California). As a result, unlike a benefit / cost analysis such as the TRC / Societal Tests, a COSS does not capture the long-run costs that DG can avoid over its full life. Moreover, most states, including Arizona, use a COSS approach based on the utility's embedded costs, not its marginal costs. Thus, a change in the utility's cost-of-service as a result of DG adoption has no direct link to how the company's costs may actually change when customers begin to produce their own power on their own premises. As discussed in the rebuttal testimony of Mr. Monsen, the COSS that APS has submitted overestimates the costs and underestimates the benefits of DG in a variety of ways. First, APS allocates costs to DG customers based on their total end use loads, rather than their lower metered usage from the grid. In effect, APS would charge DG customers for loads which the customers serve on-site using their own generation which never touches the grid. Second, Mr. Monsen shows that distribution substation and primary distribution costs should be allocated using a coincident peak allocator similar to that used for generation. Third, APS assumes that the avoided costs that result from DG output include only the avoided costs for generation energy and capacity. As summarized below, the parties to this proceeding have recognized many additional categories of benefits from DG that APS does not include in its COSS.

Q9: Are COSS used to establish the reasonableness of utility rate base additions or other types of demand-side programs, such as energy efficiency (EE)?

A9: No, they are not. A utility would object if the Commission judged the merits of a rate base addition solely on whether it raised rates for customer based on the COSS in the next rate proceeding. Utility-scale generation additions often raise rates in the short-run, for several reasons. First, the cost recovery for utility-owned resources through rate base is front-loaded into the early years. Second, large utility-scale capacity additions can result in a significant period of over-capacity. Notwithstanding their high initial net cost, such additions but may be justified based on long-term savings compared to the counterfactual alternatives. Similarly, energy efficiency programs often give consumers a rebate or incentive to adopt an energy-saving measure. The rebates increase rates in the short-run, but these costs are offset by the long-term savings. The same considerations apply to customer-sited DG resources, and the same long-term analyses should be used to judge the merits of DG resources.

Q10: Mr. Brown for APS opines that "[o]ptimally, prices should be established by market forces. This is not always possible. Where market imperfections exist, the discipline of a competitive market is missing, and it is appropriate to regulate based on costs in order to best replicate what would have happened if the market were shorn of its imperfections."[3] Are markets a viable option for assessing the benefits and costs of DG in Arizona?

A10: I agree with Mr. Brown that it is preferable to use markets and market prices to establish the benefits of DG. This is possible where energy markets exist, are well-functioning, and bear directly on certain of the benefits of DG. For example, past DG benefit/cost analyses that Crossborder has performed[4] have used the following market prices:

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[3] APS Brown, at p. 5.

[4] These studies include:

- *Evaluating the Benefits and Costs of Net Energy Metering in California*, prepared for the Vote Solar Initiative, January 2013 ("California Study"). See http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf .

- Avoided energy costs: Locational marginal prices (LMPs) in California,[5] PJM[6], and ISO-NE[7], as well as current and forward natural gas market prices throughout the U.S.[8]

- Avoided capacity costs: capacity prices in PJM[9] and ISO-NE.[10]

- Locational benefits of DG: LMPs in California[11] and Vermont.[12]

- Avoided carbon costs: California cap & trade market prices for GHG allowances.[13]

- Avoided renewables costs: REC markets in the West.[14]

The challenge in Arizona is that, unlike other regions of the country, the utilities are vertically integrated, there is no retail competition, the only wholesale market is the regional energy market at Palo Verde (which lacks visible hourly prices), there are no transparent REC or carbon markets, and there are no locational prices on the transmission grid. Our system of federalism allows states to regulate electric utilities as they see fit, and I fully respect the choice that Arizona has made. Given the lack of relevant markets within the state, an analysis of the benefits of DG in Arizona has little market data on

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- *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 2013 ("North Carolina Study"). See http://c.ymcdn.com/sites/www.energync.org/resource/resmgr/Resources_Page/NCSEA_benefitssolargen.pdf.
- Direct Testimony of R. Thomas Beach on behalf of MDV-SEIA, in Virginia SCC Case No. PUE-2011-00088, October 2011 ("Virginia Study").
- Pre-filed testimony of Patrick G. McGuire and R. Thomas Beach for Allco Renewable Energy Limited in Vermont Docket 8010, September 2014 ("Vermont Study").
- *Benefits and Costs of Solar DG for Arizona Public Service (2016 Update)*, February 2016, submitted as Exhibit 2 to my direct testimony in this case ("Crossborder APS Study").

[5] California Study.
[6] Virginia and North Carolina Studies.
[7] Vermont Study.
[8] All referenced studies.
[9] Virginia Study.
[10] Vermont Study.
[11] California Study.
[12] Vermont Study.
[13] See Crossborder APS Study, at p. 8. APS relies on California cap & trade market prices for the forecast of direct emission costs. See 2014 Integrated Resource Plan (IRP), at Figure 15.
[14] Testimony of R. Thomas Beach on behalf of the Sierra Club in Utah PSC Docket 15-035-053 (September 2015).

which to draw, and must use the available cost data, including forward-looking data such as the utility IRPs, to determine what the utilities' costs would have been absent DG.

Also, it should be noted that, even when competitive well-functioning markets do exist, they will not necessarily result in clearing prices that cover generators' full costs. For example, the California market, by design, has resource adequacy policies that require market participants to contract for sufficient excess capacity to ensure that there will not be any capacity shortages even at high levels of demand. As a result, the CAISO's market prices are not sufficient to support the entry of new generation. The CAISO's Annual Reports for many years have reported that its markets do not allow anywhere close to full recovery of the capital and operating costs of new gas-fired generation.[15] Thus, competitive markets are a means to an end (the efficient allocation of resources), but are not an end in themselves. To pay gas-fired generators average costs through bilateral contracts, or to allow utility-owned resources cost recovery through the rate base, and then to claim that the "value of solar" should be determined by energy market prices, ignores the fact that an energy market does not cover all of the costs of traditional generation resources or the full costs of the resources that DG might displace. Thus, prices established by market forces can be an important source of information, but they are unlikely to tell the entire story.

Q11: Would you agree that a significant "market imperfection" is that markets often fail to internalize the environmental costs of energy production and use?

A11: Yes. Compared to when Public Utilities Regulatory Policy Act was enacted in 1978, today we have a far deeper understanding and ability to quantify the costs to ratepayers of pollution and of the value of conserving scarce energy and water resources. Moreover, the potential impacts of global climate change have increased the importance and urgency of addressing these issues so that our children will inherit a habitable planet. The fact that there are only a few markets in the U.S. that internalize environmental costs does not

[15] For example, see CAISO, *2014 Annual Report on Market Issues and Performance* (June 2015), at Chapter 1, pp. 51-55, available at http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

mean that these impacts are zero for utility ratepayers or for the broader society. Quantifiable environmental benefits, such as reductions in carbon emissions, may not be a direct cost to ratepayers today, but they do influence resource planning and long-term costs, and they may become a direct cost in the future. Quantifiable environmental benefits should be considered in the Commission's deliberations on balancing the benefits and costs of DG.

Q12: Are there other reasons why analyses of the benefits and costs of DG are complex?

A12: Yes. Unlike a central station resource, DG is installed on the distribution system, and will impact not only the utility's generation costs, but also its transmission and distribution (T&D) costs. As a result, DG benefits can include avoiding line losses and T&D capacity costs. Solar and wind DG provide a product that is delivered directly to loads, which is a fundamentally different product than what is supplied by utility-scale solar plants or wind farms whose power must be delivered by the utility. For this reason, as discussed in my direct testimony, one cannot necessarily compare directly the busbar costs of utility-scale and DG solar and conclude that a less-expensive utility-scale solar plant offers greater benefits to ratepayers. For example, Mr. Brown makes this error in his busbar comparisons of the levelized cost of energy from various generation sources.[16]

Finally, because renewable DG is a long-term resource, evaluating its cost-effectiveness necessarily must involve long-term forecasts of many variables which are inherently uncertain. In addition, the analysis necessarily involves comparing different resource scenarios, many of which will be counterfactual. For example, demand-side resources including DG and energy efficiency will reduce the future loads that the utility must serve. However, we will never experience what the world would have been without these resources, which makes it challenging to judge the set of alternative resources that DG and energy efficiency have avoided and will avoid. However, as these resources reach significant scale, the evidence of what they are avoiding may become more apparent. For example, Pacific Gas & Electric (PG&E) recently announced to the

[16] APS Brown, at pp. 16-17.

California Independent System Operator that it is cancelling 13 sub-transmission projects in its service territory, which would have cost $192 million, as a result of "a combination of energy efficiency and rooftop solar," according to PG&E.[17]

IV. CONSIDER A COMPREHENSIVE LIST OF BENEFITS AND COSTS

Q13: Do the parties generally support a comprehensive set of benefits and costs of solar DG?

A13: Yes. There is significant commonality in the benefits and costs that parties recommend that the Commission should consider, as reflected in the following lists provided by the parties:

- TASC: Beach direct. at Table 2
- RUCO: Huber direct, at pages 17-23
- Staff: Solganick direct, Exhibits HS-2 and HS-3
- APS: Sterling direct, discussing the TVA value streams for DG
- Vote Solar: Kobor direct, at pages 27-36

The list of benefits and costs of DG that these parties recommend for Commission consideration are shown below in **Table 1**. The benefits or costs on which there is apparent disagreement on whether they should be included are shown in the table in **red** and noted with an "*".

[17] See "Cal-ISO Board Approves Annual Transmission Plan," *California Energy Markets* (No. 1379, April 1, 2016) at p. 10.

Table 1: *Summary of Benefits and Costs of DG*

Category	Notes
Benefits	
Energy	Includes fuel and variable O&M savings
* Fuel hedging	
* Market price mitigation	
* Grid Services	
Generation capacity	
Line losses	Both transmission and distribution
Transmission capacity	
Distribution capacity	
Avoided renewables costs	Avoided costs to comply with RPS
Avoided environmental costs	Includes avoided carbon emission costs
Costs	
Lost revenues	For the RIM Test
Capital and O&M cost of DG resources	For the TRC / Societal Tests
Integration	
Interconnection	If not paid by the DG customer
Program administration	

Q14: Please discuss the disagreement over whether fuel hedging benefits should be included as a direct benefit of solar DG.

A14: TASC, RUCO, Staff, and Vote Solar include fuel hedging benefits. The TVA study cited by APS witness Sterling considered a fuel hedging benefit, but did not include it because TVA study participants calculated that the benefit was negligible.[18] APS witness Brown dismisses fuel hedging benefits unless solar DG power can be produced "both in sufficient quantities and in a timely manner."[19]

The fuel hedging benefit results from the fact that renewable generation will displace and reduce the consumption of natural gas, which is the marginal fuel for producing electricity. As a result, utility ratepayers will be less subject to the volatility in natural gas prices, and in this way renewable DG can provide a fuel hedging benefit. With respect to Mr. Brown's assertion that renewable DG must be produced in sufficient volume to result in fuel hedging benefits, the strong growth of renewable DG throughout

[18] TVA Study, at p. 10. Available at www.tva.gov/dgiv.
[19] APS Brown, at p. 36.

the U.S., including in states such as Hawaii (approaching 20% penetration by number of customers[20]), California (4% penetration[21]), and Arizona (3% penetration[22]), shows that this condition has been satisfied. APS's 2014 IRP demonstrates that the utility is now planning on customer-sited resources – including energy efficiency, demand response (DR), and DG – to provide a significant share of the utility's future resource needs.[23]

Q15: Do the parties disagree on how to calculate fuel hedging benefits?

A15: Possibly. I agree with RUCO and Vote Solar that, at a minimum, the fuel hedging benefit of renewable DG should be recognized by using a long-term gas price forecast that is based on forward natural gas prices. Such a forecast represents a gas price that theoretically could be fixed for a future period, thus eliminating price volatility. However, this step may not recognize all of the costs that utility hedging programs incur to minimize volatility, including transaction costs. For example, APS's hedging program appears to have resulted in significant additional costs over an extended period.[24] To the extent that the historical record establishes these added costs for hedging, they should be included as costs that can be avoided if DG reduces the need to hedge volatile fossil fuel prices.

Q16: The testimonies of TASC, the Staff, and Vote Solar recognize that renewable DG may benefit ratepayers generally by reducing energy market prices. Do the other parties address this benefit?

A16: Lower energy market prices are a direct benefit to utility ratepayers. RUCO's proposal and the TVA methodology sponsored by APS witness Sterling do not address this

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[20] As of October 2015, 17% of all customers on Oahu and 18% of all customers on Maui had installed solar systems. See Hawaii PUC Order No. 33258, at p. 161 (Table 3, showing DG penetration). Available at http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464.

[21] California now has 3.9 GW of behind-the-meter DG and almost 500,000 solar customers connected to the grid (representing about 4% of the state's electric customers). *See California Solar Statistics*, https://www.californiasolarstatistics.ca.gov/, last visited March 15, 2016. In 2014 there were 13.3 million electric customers in California, according to Energy Information Administration data.

[22] RUCO Huber, at p. 1.

[23] APS 2014 IRP, at Attachment F.1(a)(4).

[24] Crossborder APS Study, TASC Exhibit 2, at pp. 9-10.

benefit. APS witness Brown appears to concede that renewable generation, with zero variable costs, will reduce wholesale market prices if it is produced in significant quantities. As noted above, renewable DG is now a significant resource in many states, including Arizona.

Q17: Mr. Brown claims that the concept of market price benefits represents a distortion of energy markets because renewables are "highly subsidized" in comparison to other energy resources. He cites federal tax credits, REC/SREC markets, and "the cross-subsidy inherent in net metering."[25] Please respond.

A17: All sources of energy are subsidized to a greater or lesser degree. This has been well documented in studies such as *What Would Jefferson Do? The Historical Role of Federal Subsidies in Shaping America's Energy Future* by Nancy Pfund and Ben Healey of DBL Investors (September 2011), which concludes that the subsidies received by the fossil fuel and nuclear industries have been far larger than those received by renewables.[26] Renewable DG does qualify for federal tax benefits, but there are no longer direct state subsidies in Arizona, and it is the conclusion of our updated benefit / cost study that net metering on the APS system does not represent an appreciable subsidy of DG today.[27] Further, the significant environmental benefits of DG (4.5 cents per kWh for carbon, health, and water benefits in our APS study), compared to the alternative of greater fossil generation, indicates clearly the extent to which the failure to internalize environmental costs in energy markets and utility rates represents a major subsidy of fossil energy, a subsidy paid by future generations to the present.

Q18: Please discuss grid services – a benefit of DG that other parties did not mention.

A18: Grid services are benefits of DG provided to the grid when DG is deployed with smart inverters and storage. These include voltage support, reactive power, and frequency support. In addition, by reducing loads on individual circuits, rooftop solar systems

[25] APS Brown, at pp. 37-38.
[26] This study is available at http://insights.som.yale.edu/insights/should-government-subsidize-alternative-energy.
[27] Crossborder APS Study, TASC Exhibit 2, at pp. 1-4.

reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it. All of these additional, emerging values are difficult to quantify today, because there are not currently markets for these services, and utilities do not have an incentive to procure these types of services from third-party providers. However, they have the potential to become a significant benefit in the near future, and may offset some or all of the integration costs for these intermittent renewable resources.

Q19: APS attaches to its testimony a study on the economic impacts of distributed solar in Arizona, by the L. William Seidman Research Institute at Arizona State University (the Seidman Study). Please provide your critique of this study.

A19: The Seidman study calculates the economic impacts of distributed solar deployment based on future investment scenarios provided by APS. There are a number of manifest flaws in the scenarios that APS provided:

1. **No Avoided T&D Costs.** APS's scenarios assume that the widespread deployment of distributed solar generation, located at the point of end use, would have no effect on its future needs for or investment in the grid's delivery infrastructure.[28] This is despite the fact that solar DG can reduce the peak loads on the APS grid that drive long-term T&D investments, as shown in the Crossborder benefit/cost analysis for APS[29] and as recognized by many parties in their lists of the benefits of DG.

2. **Solar's Capacity Contribution Is Too Low.** APS assigns a capacity value of just 16.5% of nameplate to solar installed in 2016 (in the Medium case), with declining percentages in subsequent years. This capacity value is far too low, given that the utility's hourly load forecast for 2016 shows that the typical solar capacity factor over the utility's peak hours[30] is 36% for south-facing systems and 53% for west-facing. As a result of APS's too-low capacity value, the amount of future capacity additions that solar

[28] See APS response to TASC Data Request 5.3.

[29] Crossborder APS Study, TASC Exhibit 2, at pp. 13-16.

[30] Defined as all hours with loads within one standard deviation of the peak hour load, with the each hour weighted by the increment between (1) that hour's load and (2) the threshold of one standard deviation below the peak hour. See Crossborder APS Study, TASC Exhibit 2, at p. 12.

can defer is significantly underestimated in the APS investment plan. This will be particularly true if, over time, west-facing installations and the use of distributed storage first mitigate and then reverse any decline in solar's capacity value.

3. **Distributed Solar Costs Are Too High.** APS's workpapers show that the utility has assumed that the federal ITC drops to 10% in 2017.[31] In fact, the 30% federal ITC has been extended at the 30% level through 2019, then declining to 26% in 2020, 22% in 2021, and 10% in 2022. As a result, additional solar investment in Arizona will benefit the state much more than the Seidman Study has estimated, because more of the costs of future solar deployment will be borne by taxpayers in other states. Further, APS uses a static estimate of future solar capital costs; the utility assumes that solar capital costs decline by just 1% per year from 2016-2035. This would be far slower than the solar cost declines of about 7% per year experienced in recent years as documented in the LBNL and NREL data shown below in the figures provided in response to Commissioner Little's Question No. 7.

Finally, a basic flaw in the Seidman study is its assumption that the value of a successful and growing distributed solar industry is measured solely by the industry's impact on APS, the local utility. Arizona, with its abundant solar resources, research universities that do significant solar research, and position in the heart of the U.S. Southwest, could be a hub for solar activity at all scales in the region, in the rest of the U.S., and in the world. In other words, the true upside for Arizona is not just the economic activity that the solar industry could generate by making electricity in APS's service territory, but the economic activity in Arizona related to providing solar services to the region, the U.S. and export markets. This upside potential is not at all considered in the Seidman Study.

[31] See APS response to Vote Solar Data Request 3.24. See the tab "*SEND – DE Costs*," Cell N2, showing the use of a 30% ITC in 2016 and 10% thereafter.

V. CONSIDER THE MULTIPLE PERSPECTIVES OF KEY STAKEHOLDERS

Q20: Why is it important for the Commission to consider the benefits and costs of DG from multiple perspectives?

A20: Traditionally, the Commission's role is to balance the interests of, first, ratepayers as a whole and, second, the utility and its shareholders. Customer-owned or customer-sited DG introduces a third key perspective – the participating ratepayers who make long-term investments in renewable DG. If a sustainable, innovative DG industry is to succeed in Arizona, the Commission must respect the long-term investments that tens of thousands of Arizona utility customers have made in renewable DG. As a result of the presence of this additional key stakeholder, the Commission cannot just consider a benefit/cost test (such as the RIM Test) that focuses only on non-participating ratepayers.

Q21: What is the most important perspective for the Commission to review?

A21: The TRC/Societal Tests consider the benefits and costs of renewable DG from the perspective of all ratepayers and the broader community as a whole. In these tests, the costs are the capital and operating costs of the new resource, while the benefits are the costs that the utility will avoid as a result of the output of the new resource as well as the societal and environmental benefits of these resources (in the Societal Test). This is the same perspective that the Commission uses to evaluate other demand-side energy efficiency programs (through the Societal Test) or to review utility-owned generation plants for reasonableness in ratemaking, certification, or resource planning cases. Mr. Brown for APS spends many pages of his testimony complaining that "value of solar" analyses do not treat DG on the same basis as other possible new resources.[32] If that is a concern of the Commission, the clear solution is to adopt the use of the Societal Test as the primary means to evaluate DG in ratemaking and resource planning cases. This would evaluate the cost-effectiveness of DG on the same basis as this Commission evaluates the cost-effectiveness of other types of both demand- and supply-side resources.

[32] APS Brown, at 15-18 and 60.

Q22: RUCO's witness Mr. Huber acknowledges that the Commission evaluates energy efficiency resources using the Societal Test, yet he recommends that the RIM test should be emphasized in ratemaking proceedings that impact demand-side DG resources.[33] He bases this recommendation on an assertion that DG has certain differences from energy efficiency. Please comment on these differences.

A22: His first and last points are that solar PV is less accessible to a broad range of customers than energy efficiency measures, and thus the benefits of solar PV to participants are concentrated in a smaller group of customers. APS witness Mr. Brown repeatedly makes the same point in a more pointed fashion, suggesting that, because rooftop solar allegedly is adopted mostly by higher-income individuals, it has a "regressive social impact."[34]

First, this point ignores the significant progress that the solar industry has achieved, as a result of solar leasing and power purchase agreement programs, in making rooftop solar accessible to middle-income Americans. For example, in California, one of the goals of the California Solar Initiative was to make rooftop solar a mainstream energy choice. Significant progress toward that goal has been achieved – since 2014, more than half (53%) of the rooftop solar installed in California has been deployed by homeowners living in zip codes where the median owner-occupied income is $55,000 to $70,000 per year.[35] These are certainly middle class customers. The way to sustain this progress is to continue to bring distributed solar to scale. The way forward is <u>not</u> to adopt a regulatory framework that unreasonably requires solar customers again to pay a significant premium in their overall cost of electricity if they adopt solar, as unfortunately has occurred in Nevada and in the Salt River Project's service territory. Such a result simply would turn back the clock so that only the truly wealthy could afford solar.

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[33] RUCO Huber, at pp. 10-12.

[34] APS Brown, at p. 24 and 46-47.

[35] See the Kevala Analytics white paper on the income distribution of rooftop solar customers. Available at http://kevalaanalytics.com/wp-content/uploads/Kevala-CA-Residential-Solar-Income-Analysis.pdf.

Second, the means to make solar accessible to renters, customers whose homes are shaded, or lower-income customers is through programs targeted at these customers, such as community solar and programs for disadvantaged communities. I encourage the Commission to consider the targeted solar programs that other states have adopted:

- Massachusetts has a successful program of remote or virtual net metering, whereby centralized solar installations can earn net metering credits at small commercial rates, and can assign those credits to subscribing customers at different locations in the same community.[36]

- California has targeted subsidy programs to install solar on both low-income single- and multi-family homes, and is developing a new net metering program in disadvantaged communities.[37]

- Other states are pursuing a wide range of community solar models.[38] In order to allow for the greatest amount of innovation, the Commission should consider community solar programs where the shared solar development opportunity is open to all types of entities – utilities, public agencies, and private developers.

Third, more generally, the U.S. has a capitalist economy that is the most innovative in the world. The way that technological innovations are diffused in our economy is typically that they are initially expensive, and available only to higher-income consumers or enthusiasts, until they can be brought to scale. This is a pattern that has been repeated from the automobile to televisions to personal computers to cell phones to smart phones, and now to solar systems and electric vehicles. Mr. Brown's complaint that rooftop solar has a "regressive social impact" echoes the complaints made by socialists and buggy-owners in the early 1900s about the first new-fangled automobiles

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[36] See, for example, National Grid's description of its Massachusetts net metering programs https://www9.nationalgridus.com/masselectric/home/energyeff/4_net-mtr.asp.

[37] See the California Single-family Affordable Solar Homes (SASH) and the Multi-family Affordable Solar Homes (MASH) programs, at http://www.cpuc.ca.gov/General.aspx?id=3043 and https://www.pge.com/en/mybusiness/save/solar/mash.page. Also, see CPUC Decision No. 16-01-040, at pp. 37-42, 101 and 103 for a discussion of the Disadvantaged Communities program.

[38] For a listing of community solar projects, see https://www.communitysolarhub.com/. Also see the Interstate Renewable Energy Council's work on shared renewables, at http://www.irecusa.org/regulatory-reform/shared-renewables/. For different community solar models, see http://www.seia.org/policy/distributed-solar/shared-renewablescommunity-solar.

owned by the wealthy.[39] His complaint suggests that his remedy would be for the government to intervene so that its regulated proxy, the utility, would dole out a limited number of utility-owned rooftop solar systems to customers by lottery. This clearly would not be the best path, or the American way, to foster innovation and scale in a promising clean energy technology.

Q23: Mr. Huber also argues that DG has different impacts on the utility system than energy efficiency. For example, he argues that solar DG has "less diverse" impacts than energy efficiency, and that solar DG merely "masks" end use loads, rather than reducing them completely. He also notes that integrating solar resources can increase utility costs.[40] Are these valid reasons why DG should be judged by a different standard than other types of resources?

A23: No. As Mr. Huber admits, energy efficiency and demand response measures also have diverse impacts on the grid – some predominantly reduce baseload energy use (like more efficient refrigerators), while others moderate peak demand (like high efficiency air conditioners). Just as the different characteristics and benefits of various EE and DR resources are modeled in the Societal Test, so too can the impacts and benefits of solar DG be analyzed based on its own attributes. With respect to solar DG only "masking" the loads it serves, this effect is small, given the large number of DG systems, their low forced outage rates, and the fact that they do not all fail at once.[41] Moreover, the same uncertainty is also present for EE and DR resources. It is well-known that EE resources exhibit a "rebound effect," whereby a portion of the benefits of an EE measure are eroded by the greater use of the more efficient device, compared to the less-efficient one. Similarly, the utility cannot be certain of the exact number of DR customers that will respond to reduce demand when called upon to do so. With respect to the impacts of

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[39] See Gartman, David, *Auto-Opium: A Social History of American Automobile Design*, at pp. 36-37.
[40] RUCO Huber, at pp. 11-12.
[41] For example, if 10,000 DG systems with an average size of 10 kW (100 MW total) have a forced outage rate of 1%, on average just 100 units will be out of service at any one time, and the average additional load that has to be served is just 1 MW. This is far easier for the system to handle than the sporadic outages of a 100 MW generator, which requires that an additional 100 MW of generation be available to replace it when it is out.

solar DG on increasing the costs to manage the grid, such as the impacts on ramping and regulation requirements, these effects are also produced by utility-scale solar generation, and integration studies can delineate the costs associated with these impacts. Generally, as noted in our APS Study, integration costs are small at the current penetration of solar resources.[42] I agree that these integration costs should be included in benefit/cost analyses of solar DG, based on the wealth of new information that is becoming available as control areas in the U.S. integrate larger amounts of variable renewable generation.

Q24: What should the role of the RIM Test be in the Commission's evaluation of renewable DG?

A24: The Commission should use the Participant and RIM Tests to ensure that there is an equitable balance of costs and benefits between those ratepayers who install DG systems and those who do not. The Participant and RIM Tests are the opposite sides of the same coin, as shown in **Table 1** of my direct testimony. The primary <u>benefits</u> of DG for participating ratepayers in the Participant Test are bill savings; in the RIM Test, these bill savings are the primary <u>costs</u> of DG for non-participating ratepayers, i.e. the utility's lost revenues. By looking at both perspectives, and ensuring that both tests yield results that are reasonably close to 1.0, the Commission can ensure that renewable DG remains a viable choice for Arizona ratepayers without presenting an undue burden on ratepayers who do not exercise this competitive option. By finding this balance, the Commission will best serve the public interest of all ratepayers in Arizona.

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[42] Crossborder APS Study, TASC Exhibit 2, at p. 23. As another example from another region, *see* the 2014 integration study for Duke Energy, *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014), at Table 2.5 and Figure 2.51. This study calculates that, with 673 MW of solar PV capacity on the Duke utility systems in 2014, integration costs would be about $0.0015 per kWh.

VI. RESPONSES TO COMMISSIONER'S QUESTIONS

A. Commissioner Little

1. How were the value and cost of solar considered in the development of the current net metering tariffs?

Response: As noted in the testimony of Vote Solar's witness Kobor, the Commission's Decision 69127 adopted net metering tariffs and found that renewable DG would provide benefits ("value") including reducing peak period costs for generation (both energy and capacity), as well as decreasing loads and avoiding costs on the transmission and distribution systems.[43]

2. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?

Response: In recent years, the declining cost of panels has allowed the solar industry to maintain the value proposition for customers even as many direct state incentives have been reduced to zero, including in Arizona. The capital cost of solar equipment is the primary cost of solar DG to participating customers and is a principal cost in the Participant Test. As shown in the Participant Test results in our updated benefit / cost study for APS, the current cost of solar for participating residential solar customers (17 c/kWh) is in balance with the bill savings realized by these customers (17.9 c/kWh).[44]

3. Is it appropriate to factor the cost of the panels into the reimbursement rate for net metering? If so, how?

Response: As discussed above, the Commission should ensure that there is an equitable balance between participating and non-participating customers. This balance appears to exist today in the residential market, with the current net metering rules and the existing retail

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[43] Decision 69127, at Appendix B, page 6, Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules, No. RE-00000C-05-0030 (Ariz. Corp. Comm'n, Nov. 14, 2006), Barcode No. 0000063561.

[44] Crossborder APS Study, TASC Exhibit 2, at Table 1, p. 3.

rate structure. The interests of participating solar customers are measured by the results of the Participant test, in which the cost of panels is the principal cost. If net metering is changed, or rates are restructured, such that the bill savings for solar customers are reduced significantly, the economics of renewable DG will no longer support customer adoption of these technologies.

4. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?

Response: The cost and value of DG solar can vary by location as the result of many factors, including the quality of the solar resource, whether the distribution system is constrained, the line losses avoided, and the location of the customer on the state's transmission grid. Developing locational costs and values is a complex undertaking, and could require locational marginal pricing (LMP) on the grid in Arizona and the development of distribution resource plans (DRPs) by the Arizona utilities, similar to the plans now under development by utilities in New York and California. Unless LMPs and DRPs are developed in Arizona, it may be difficult to assemble the information that would be needed to reflect this locational variability in rates.

5. How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?

Response: As shown in the Crossborder APS Study, west-facing panels have significantly higher capacity value than south-facing, because the output of west-facing systems peaks later in the afternoon and thus coincides more closely with the peak loads that drive capacity costs for both generation and T&D. The same is true of the use of tracking. The west-facing siting of panels and the use of tracking can be encouraged through the increased use of TOU rates. To increase awareness of the higher benefits of west-facing systems and to offset the lower annual production of west-facing panels, the Commission should consider direct upfront incentives for west-facing systems, just as incentives are used to overcome market barriers to customer uptake of energy efficiency measures.

6. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?

Response: The value of solar can be increased significantly when paired with storage. For example, the generation and T&D capacity value of solar alone is 20% to 55% of nameplate. These percentages can be increased significantly, perhaps to 80% or more, by using storage to shift peak solar output by a few hours so that it coincides with the times of peak loads at both the system and distribution levels. Storage also can provide ancillary services and increase the reliability and resiliency of electric service to critical loads. However, storage presently is expensive, and requires financial and policy support to be economic and to be brought to scale. In 2013, California adopted a storage portfolio standard with a goal of 1.325 GW of storage installations by 2020,[45] supported through utility storage RFOs and incentives for distributed storage available through the state's self-generation incentive program (SGIP).[46] Importantly, at least 50% of the available storage capacity will be developed and owned by third-parties, to stimulate a diverse and competitive market for storage.[47] The Commission should consider comparable programs to incent storage development in Arizona.

Storage paired with solar also can serve electric loads without the use of the grid, and such grid defection will become increasingly economic as distributed storage costs decline with increasing scale. In my opinion, significant grid defection would be an unfortunate result, because the combination of grid-connected solar plus storage can offer significant benefits to all customers. Grid defection can be minimized with reasonable pricing and incentives for grid-connected solar DG that balance the interests of both

[45] See http://www.greentechmedia.com/articles/read/california-passes-huge-grid-energy-storage-mandate.

[46] Information about California's electric storage mandate and SGIP program are available at http://www.cpuc.ca.gov/general.aspx?id=3462 and http://www.cpuc.ca.gov/general.aspx?id=5935.

[47] See CPUC Decision No. 13-10-040, at pp. 51-52. Available at http://www.cpuc.ca.gov/general.aspx?id=5935.

1 participating and non-participating consumers. This is also the conclusion of a recent
2 major study of the economics of grid defection throughout the U.S.[48]

3 7. How does the value and cost of DG solar compare to the value and cost of community
4 scale and utility scale solar? How do the value and costs of DG solar compare to that of
5 wind or other renewable resources? How does the value and cost of DG solar compare to
6 that of energy efficiency?

7 **Response:** As discussed above and in my direct testimony, solar and wind DG provide a
8 retail product that is delivered directly to loads. This is a fundamentally different
9 product than the wholesale power provided by utility-scale solar plants or wind
10 farms whose output must be delivered by the utility. Any economic comparison
11 of DG to utility-scale generation must consider the costs required to deliver the
12 utility-scale generation to loads. Further, although utility-scale solar is less
13 expensive than DG solar due to economies of scale, the cost difference between
14 these resources has narrowed in recent years, as shown in the following figures
15 from Lawrence Berkeley National Lab's (LBNL) reports tracking solar costs.
16 The first figure shows median utility-scale solar costs averaging $2.30 per watt-
17 DC in 2014.[49]

[48] See Rocky Mountain Institute, *The Economics of Grid Defection* (April 2015), available at http://www.rmi.org/electricity_grid_defection.

[49] From Mark Bolinger and Joachim Seel, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (LBNL, September 2015). Available at https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf.

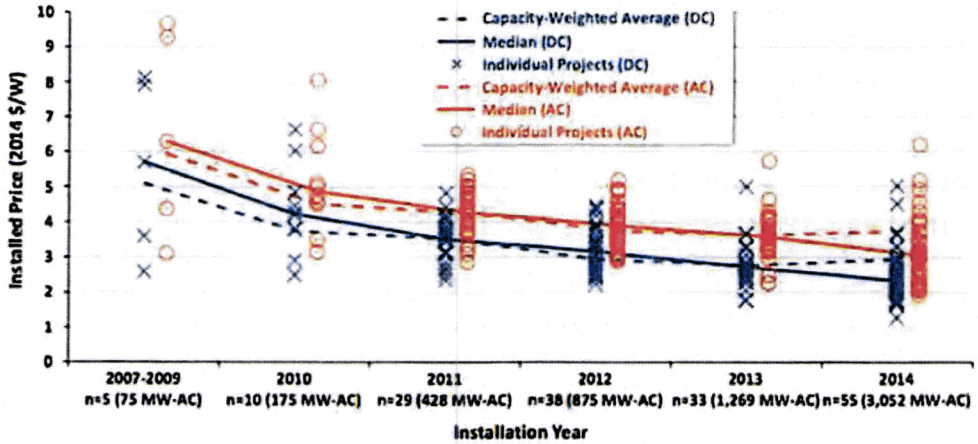
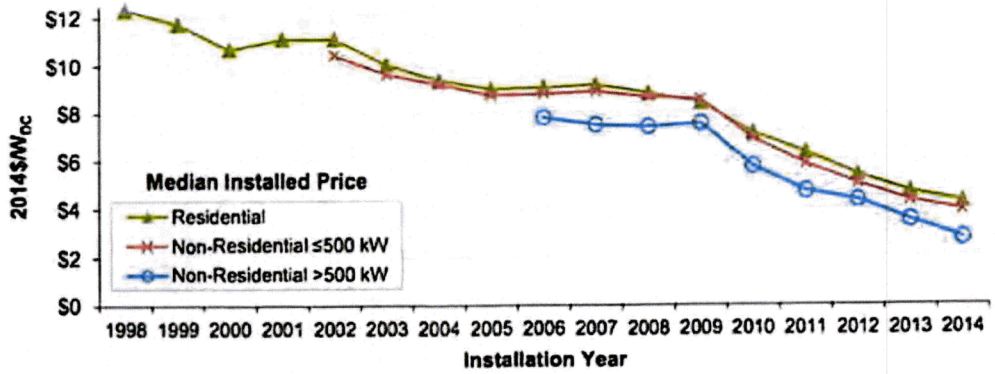


Figure 6. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

The second figure presents rooftop solar costs.[50] The costs of large commercial rooftop arrays (> 500 kW) reached $2.40 per watt-DC in 2014, very close to utility-scale solar costs at $2.30 per watt-DC. Smaller rooftop projects averaged about $4.00 per watt-DC. These charts show that, since 2007, the cost difference between small rooftop and utility-scale solar systems has narrowed from $3.50 per watt-DC in 2007-2009 to $1.70 per watt-DC in 2014. This narrowing of the cost difference between rooftop and utility-scale solar projects is due in significant part to reductions in the soft costs of rooftop installations.

[50] From Galen L. Barbose and Naïm R. Darghouth, *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States* (LBNL, August 2015). Available at https://emp.lbl.gov/sites/all/files/lbnl-188238_2.pdf.



Notes: See Table 1 for sample sizes by installation year. Median installed prices are shown only if 20 or more observations are available for a given year and customer segment.

Figure 7. Median Installed Price Trends over Time

8. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

Response: The capacity value of solar DG used in benefit / cost studies recognizes the intermittent nature of solar output. There are well-accepted methods for calculating the capacity value of solar and wind given their intermittency (see, for example, the Peak Capacity Allocation Factor method used in the Crossborder APS Study, at pages 12-13 and 16). In addition, integration cost studies calculate the cost impacts of operating the grid with a higher penetration of intermittent wind and solar resources. The use of distributed storage definitely would reduce the intermittency of DG solar, and will increase its value.

9. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

Response: Solar output is partially but not completely coincident with peak demand. This partial coincidence is fully considered in the methods used to value the capacity provided by solar resources. The analyses in the Crossborder APS Study determined that the

capacity value of solar in Arizona ranges from 20% to 55% of nameplate capacity, depending on the orientation of the array and the customer class served.[51] As discussed above, the Commission could increase the capacity value of solar significantly by incenting west-facing systems and distributed storage.

10. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

Response: Yes. Technologies such as smart inverters and storage can enable solar (or the loads which solar serves directly) to be more dispatchable. These technologies will increase the value of solar significantly, and mitigate the erosion of solar's capacity value as its penetration increases.

11. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?

Response: Significant distribution system modification or upgrades will be necessary only at far higher penetrations of solar DG than Arizona is now experiencing. Experience in Hawaii, where solar penetration is approaching 20% of all customers, shows that distribution systems can accommodate significant exports from high penetrations of solar DG facilities, at levels above even the minimum daytime distribution system load, without charging DG customers for ongoing costs beyond those identified through the interconnection process.[52] Arizona is presently at about one-sixth the level of DG penetration that Hawaii is experiencing. APS has stated in discovery that it has not incurred significant costs today to accommodate exports from DG projects, even when

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[51] Crossborder APS Study, TASC Exhibit 2, at pp. 12-13 and 16.

[52] For example, the Hawaiian Electric Company (HECO) maintains public "locational value maps" of its distribution system which show the amount of interconnected DG on each circuit, as a percentage of the circuit's peak load and its minimum daytime load. Many circuits have DG capacity in excess of 120% of the daytime minimum load, which means that the circuit is likely to backfeed to upstream portions of the system. *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps.

these exports cause isolated instances of reverse flow on its residential distribution feeders.[53]

12. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

Other impacts to consider include:

a. Job impacts associated with DG solar installations;
b. Job impacts associated with closure of fossil fuel plants (and mines) displaced by DG solar;
c. Distribution of DG solar economic benefits between DG installers, customers who install DG solar, PV panel manufacturers and others;
d. Impact of DG solar deployment on overall energy costs and those costs' impacts on economic activity;
e. Effect of DG solar deployment on natural gas and coal prices; and
f. Opportunity costs associated with incenting DG solar, e.g., funds spent on DG solar cannot be spent on other renewable energy resources or energy efficiency.

Response: The secondary economic impacts of DG solar deployment are varied, and can be estimated in certain respects. Solar DG will reduce market prices for natural gas and wholesale power, and these direct benefits for ratepayers are estimated in the Crossborder APS Study, at pages 10-11. This estimate does not include the broader economic benefits of these price reductions. The Crossborder APS Study also estimates, at pages 20-21, the increased local economic activity in the community where the solar DG is located, as a result of the installation of renewable DG. The concept of "opportunity costs associated with incenting DG solar" assumes that Arizona ratepayers are subsidizing DG solar. However, there are no longer direct state incentives for DG solar, and it is our conclusion, based on the Crossborder APS Study, that net metering in Arizona does not represent an appreciable subsidy today. Furthermore, the capital costs for solar DG are paid for or supported by customers themselves and by federal tax credits, not through financing by the utility. This represents new sources of capital for building clean energy infrastructure in Arizona. Finally, the fact that renewable DG produces a net benefit in the TRC and

[53] See APS response to TASC Data Request 4.4.

Societal Tests means that it is likely to result in a net economic benefit for the state of Arizona.

13. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

Response: The cost of DG solar should continue to fall as penetration increases. The value of DG solar (in terms of its ability to defer capacity) may decrease as penetration increases; for example, if peak loads shift to later in the afternoon. However, this drop in benefits can be offset or reversed by greater use of west-facing or tracking systems and the increased use of distributed storage. See the responses to Questions 5, 6, 9, and 10 above for suggestions for incentives to encourage such innovations.

14. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

Response: Fuel cost savings to the utility associated with DG solar are an integral part of the benefits of DG solar. See Crossborder APS Study, at pages 8-10. One means to deal with the uncertainty in future fuel prices is to use forward natural gas prices and hedging costs, which represent the costs to the utility to minimize the future volatility in its natural gas costs. Alternatively, high, low, and base scenarios for future fuel prices can be examined.

15. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?

Response. Yes, DG solar will reduce the future need for transmission capacity, in conjunction with other demand-side resources such as energy efficiency and demand response. The marginal cost of transmission capacity can be estimated, or the proxy of the utility's current FERC-regulated long-term wholesale firm transmission rate can be used (see Crossborder APS Study, at pp. 13-15).

16. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?

Response. Yes, DG solar will reduce the future need for distribution capacity, again in conjunction with other demand-side resources such as energy efficiency and demand response. Marginal distribution costs can be calculated (see Crossborder APS Study, at pp. 15-16). More broadly, I anticipate that there will be many beneficial reasons in the future for utilities to upgrade and to modernize their distribution grids. Integrating DG is just one of these. Others include:

1. Reducing the effects of outages;
2. Improving workforce and asset management;
3. Reduced costs for distribution maintenance;
4. Greater visibility for system operators into local grid conditions;
5. Reduced response times to customer outages;
6. Development of a charging infrastructure for electric vehicles;
7. Opportunities to reduce stationary source air emissions through further electrification of buildings and industrial processes; and
8. Allowing deployment of distributed storage, which in turn has numerous potential benefit streams – energy arbitrage, capacity deferral, ancillary services, enhanced reliability and resiliency, and power quality.

There is significant potential for the intelligent deployment of DG to reduce the costs associated with grid modernization. Solar City recently released an important white paper, *A Pathway to a Distributed Grid*, which quantifies the net benefits of distributed energy resources ("DER") – including both DG and other distributed resources such as smart inverters, storage, energy efficiency, and controllable loads – and shows that they are a cost-effective approach to grid modernization. This study reviews the recent grid modernization proposal of Southern California Edison, and concludes that only 25% of the proposed investments are related to DER integration. The other 75% are intended to realize the other benefits listed above.[54]

[54] This Solar City white paper is available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

1 17. Does the grid itself add value to DG solar? If so, how should the value of the grid be
2 considered when assessing the value and cost of DG solar?

3 **Response:** Yes, the grid adds value to DG solar, and DG solar adds value to the grid. Both
4 should be considered. As discussed in my direct testimony, a DG customer pays for the
5 value that the grid adds whenever the customer's meter runs forward. The DG customer
6 pays the same retail rate that all other customers pay for the grid's valuable services. A
7 regular, non-DG customer can spike a demand on the grid when the air conditioner is
8 turned on, just as a solar customer may spike a demand on the grid when a cloud comes
9 overhead. Both customers pay the same amount for this grid service by running the
10 meter forward at the retail rate.

11 18. Does the deployment of DG solar result in a reduction in the use of water in electric
12 generation? How should this be considered when determining DG solar value?

13 **Response:** Yes, there are important water-saving benefits from renewable generation. These
14 benefits are discussed and calculated in the Crossborder APS Study, at pp. 19-20.

15 19. Are there disaster recovery or backup benefits associated with the deployment of DG
16 solar? Are they reliable and quantifiable enough to determine tangible benefits that might
17 accrue to the grid?

18 **Response:** Yes, although these benefits are challenging to quantify today. Renewable DG
19 resources are installed as thousands of small, widely distributed systems and thus are
20 highly unlikely to fail at the same time. Furthermore, the impact of any individual outage
21 at a DG unit will be far less consequential, and less expensive for ratepayers, than an
22 outage at a major central station power plant.[55] DG is located at the point of end use, and
23 thus also reduces the risk of outages due to transmission or distribution system failures.
24 One study of the benefits of solar DG has estimated the reliability benefits of DG from a
25 national perspective.[56] The study assumed that a solar DG penetration of 15% would

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[55] California has recent experience with the costs of such an outage – the prolonged and expensive shutdown and eventual closure of the San Onofre Nuclear Generating Station as a result of a design flaw in the replacement steam generators.

[56] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the wholesale level.

However, most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain business, institutional, and government functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancement that would eliminate or substantially reduce these interruptions. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the timely alternative source of power when the grid is down. DG also can supply the some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. As a result, it is difficult to estimate the share of these reliability benefits that should be assigned to solar DG alone. Nonetheless, renewable 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 will be developed in the future. Accordingly, the reliability and resiliency benefits of wider renewable DG deployment should be recognized as a broad societal benefit.

20. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

Response: If these costs exist today, they are small. Integration studies have calculated the increased regulation and ramping ancillary service costs associated with higher penetrations of intermittent renewable resources. These costs are likely to be offset in the future as smart inverters provide voltage and frequency support on the distribution system and as distributed storage provides ancillary services.

B. Commissioner Stump

1. The Commission's May 7, 2014 Workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

Response: Solar and wind DG provide a retail product that is delivered directly to loads, a fundamentally different product than the wholesale power provided by remote utility-scale solar plants or wind farms whose output must be delivered by the utility. See Section VII of my direct testimony and the response to Commissioner Little's Question 7 above.

2. Why argue that a value-of-solar proceeding is important only for resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG?

Response: Understanding the benefits and costs of renewable DG is important for ratemaking as well as resource planning cases. See Section VI of my direct testimony.

3. In 2014, lost fixed costs associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per-customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

Response: As cited by Commissioner Stump, the lost revenues associated with EE are significantly greater than for DG, at current levels of penetration. The lost revenues per customer may be lower for EE than for DG, but many of the impacts of EE and DG on

the grid are similar, and can be evaluated with the same benefit / cost analyses. See the response to Q&A No. 21 above.

4. How do we calculate regressive social costs into the value of solar, given that non-solar utility customers subsidize solar customers?

Response: I disagree that there are "regressive social costs" from the deployment of a new technology such as DG, or that non-solar customers subsidize solar customers. The fact that new technologies are first adopted by wealthier individuals is how our innovative, capitalist economy works, as discussed in response to Q&A No. 20 above. The best means to ensure that renewable DG becomes a resource available to all utility customers is to continue to grow its scale, increase its penetration, reduce its cost, and adopt programs that make solar and other renewables available to renters, homeowners with shaded homes, and lower income families and communities.

5. Are solar DG users being overcompensated or undercompensated for remitting excess solar power to the utility at the retail rate?

Response: Based on the results of the Crossborder APS Study, solar DG users are being compensated at the right level today for remitting excess solar power to the utility at the retail rate. As stated in my direct testimony, if the Commission finds that it is necessary to adjust the balance of the interests between participating and non-participating ratepayers, the Commission can do so through rate design. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DG, such as a minimum bill. Fixed charges, demand charges, or rate design changes that apply only to DG customers should be avoided, due to problems with customer acceptance, undue discrimination, and the future potential for customer bypass of the utility system.

6. To what degree do intermittency and non-dispatchability affect the value of solar?

Response: See the responses to Commissioner Little's Questions 8, 9, and 10 above.

7. How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U.S. installation costs into a value-of-solar determination?

Response: A portion of the cost reductions achieved for solar DG in recent years has been from reductions in the "soft costs" that have been the primary reason why U.S. solar prices are higher than those in other markets such as Germany.[57] See the responses to Commissioner Little's Questions 2, 3, and 7 above.

8. In value-of-solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words, are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower instillation costs? How does the cost and value of DG compare with alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that of utility-scale and community-scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility-scale or community-scale solar?

Response: Evaluating solar DG on the same basis that other demand- and supply-side resources are evaluated, using the TRC/Societal Tests, would be a good first start in comparing DG with other renewable and fossil resources on a level playing field. Such analyses also must recognize that solar DG provides a retail product that is different than the wholesale product supplied by utility-scale resources. See Section VII of my direct testimony and the response to Commissioner Little's Question 7 above.

9. How should we go about attempting to quantify largely externalized and unmonetized factors, such as projected financial, energy security, social, and environmental benefits? How are long-term forecasts accurately incorporated into present value-of-solar calculations?

Response: These factors should be quantified to the extent we are able to do so. A failure to quantify them implicitly assigns a value of zero to these factors, an assumption that clearly is wrong. These values should inform the Commission's deliberations on the right balance between stakeholders. See the Crossborder APS Study, at pages 17-21 discussing and quantifying the carbon, health, water, and local economic benefits of solar

[57] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (LBNL, February 2013).

DG, as well as the response to Commissioner Little's Question 19 above, discussing the reliability and resiliency benefits of solar DG. Long-term forecasts should start with the utility's most recent resource plan, and should reflect input from a broad range of parties.

10. Despite recognized advantages, a number of states are reexamining their traditional net metering policies and underlying rate designs. The increasingly pervasive review of conventional net metering policies by states is attributable to a multitude of trends, including decreasing solar rebate incentives, rapid encroachment of renewable portfolio standards, the realization of net metering caps, as well as raised public awareness surrounding prospective cost-shift concerns.

For instance, the Hawaii Public Utilities Commission brought an end to the state's net metering program when it cut payments to new solar customers by approximately half the going rate.[58] Nevada alternatively reduced payments to existing solar customers from the retail to the wholesale rate and raised customers' fixed charges to cover the cost of using the grid.[59] Moreover, the California Public Utilities Commission recently approved a NEM 2.0 successor tariff, which effectively preserves retail rate payments for residential DG systems while imposing new interconnection fees, non-bypassable charges, and a shift to time-of-use rates for DG customers.[60]

a. Given this context, how did Hawaii, Nevada, and California value the costs and benefits of net-metered solar?

b. What analyses on the cost of solar did these states use when they changed their net metering policies in light of an acknowledged cost-shift? Did such analyses adequately account for the costs associated with redesigning and maintaining the distribution system to accommodate DG?

c. How would a value-of-solar methodology facilitate the successful implementation of similar updated policies in Arizona?

Response: Of the three states, California was the only one whose net metering docket considered benefit / cost analyses of solar DG from all of the key perspectives: participant, non-participant, and all ratepayers/society as a whole. These analyses were provided by the parties through the common "Public Tool" spreadsheet tool developed by

[58] Decision No. 33258, Docket No. 2014-0192 (Haw. Pub. Utils. Comm'n Oct. 12, 2015).
[59] Document IDs 8412 & 8414, Docket Nos. 15-07041 & 15-07042, (Nev. Pub. Utils. Comm'n Dec. 23, 2015).
[60] Decision No. 16-01-044, Docket No. R.14-07-002 (Cal. Pub. Utils. Comm'n Jan. 28, 2016).

the California Commission, which all parties in the CPUC's net metering docket were required to use.

Nevada relied on a cost of service study performed by the utility, and did not comprehensively update a 2014 benefit / cost study which showed that the benefits and costs of net metering were reasonably well-balanced in that state. Nevada also did not evaluate the impacts of its new DG rates on the economics of participating solar DG customers in Nevada.

Hawaii is a special case whose unique circumstances must be recognized, including the island grids, the high existing penetration of solar DG, the state's extremely high electric rates due to the use of fuel oil as the marginal fuel, and Hawaii's goal of achieving 100% renewable electric generation. The Hawaii PUC revised its net metering policies without conducting a comprehensive benefit / cost study, finding that the new export rate and DG service options would reduce the impacts of net metering on non-participating customers, without quantifying the need for or extent of this change. Similarly, without undertaking a specific analysis of the solar market in Hawaii, the Hawaii commission concluded that its changes "offer compelling value propositions to customers who may choose to interconnect new DER systems" and thus "the interim options approved herein provide near-term balance, customer choice, and value to both participating and non-participating customers."[61] In replacing net metering, the Hawaii commission adopted an uncapped option for customers to self-supply their loads with DG, and a capped option that allows exports to the grid at a new, lower export rate. Hawaii will be conducting a more detailed analysis in Phase 2 of its DG proceeding.[62]

Q25: Does this conclude your prepared rebuttal testimony?

A25: Yes, it does.

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[61] Hawaii PUC Decision No. 33258 (Docket No. 2014-0192, October 12, 2015), at pp. 166-167.

[62] *Ibid.*, at p. 167.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

REBUTTAL TESTIMONY OF WILLIAM A. MONSEN

EXHIBIT A

Errata corrections to

Direct Testimony of R. Thomas Beach

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

ERRATA CORRECTIONS TO DIRECT TESTIMONY OF R. THOMAS BEACH

Errata to Exhibit 2 to Direct Testimony of R. Thomas Beach on behalf of TASC

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

Page	Original	Corrected
8	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.3 cents per kWh, in 2014 dollars.	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.2 cents per kWh, in 2016 dollars.
14	The result is a solar DG value for transmission capacity equal to about $14 per kW-year for south-facing systems (i.e. $37 per kW-year x 39% contribution to peak) and $19 per kW-year for west-facing.	The result is a solar DG value for transmission capacity equal to about $16 per kW-year for south-facing systems (i.e. $43 per kW-year x 36% contribution to peak) and $23 per kW-year for west-facing.
14	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $8 per MWh (0.8 cents per kWh) for south-facing systems and $13 per MWh (1.3 cents per kWh) for west-facing systems.	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $9 per MWh (0.9 cents per kWh) for south-facing systems and $16 per MWh (1.6 cents per kWh) for west-facing systems.

EXHIBIT
TASC 2.9
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

REBUTTAL TESTIMONY OF WILLIAM A. MONSEN

REBUTTAL TESTIMONY OF WILLIAM A. MONSEN
ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE (TASC)
(Docket No. E-00000J-14-0023)

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REBUTTAL TESTIMONY OF WILLIAM A. MONSEN
ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE (TASC)
(Docket No. E-00000J-14-0023)

I. Introduction and Summary of Testimony

Q. Please state your name, position and business address.

A. My name is William A. Monsen. I am a Principal at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. On whose behalf are you providing this testimony?

A. I am providing this testimony on behalf of the Alliance for Solar Choice (TASC).

Q. Please describe you background, experience and expertise?

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including Arizona, Colorado, California, Nevada, New England, and Wisconsin. Prior to joining MRW, I worked at Pacific Gas and Electric Company ("PG&E"). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley, and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison.

Q. Have you previously testified as an expert witness?

A. Yes. I have previously testified before the Commission on behalf of AES NewEnergy and Strategic Energy LLC. In addition, I have testified before the California Public Utilities Commission (CPUC) on behalf of the City of San Diego, the City of Long Beach, Bear Mountain, Snow Summit, the Independent Energy Producers Association, the California Cogeneration Council, Duke Energy North America, the Alliance for Retail Energy

Markets, the Center for Energy Efficiency and Renewable Technologies, the Local Governmental Commission Coalition, Clearwater Port, Commercial Energy, and The Vote Solar Initiative. I have also submitted testimony in proceedings before the Federal Energy Regulatory Commission as well as state utility commissions in Arizona, Colorado, Massachusetts, Oregon, and Nevada. Additional information about my qualifications is provided in Exhibit WAM-1.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony reviews Arizona Public Service's (APS's) testimony related to the cost of service studies for Net Energy Metered (NEM) customers in the residential customer class.[1] Based on this review, I propose various changes to the underlying assumptions used in those cost of service study to correct APS's errors. Using these corrected assumptions, I develop corrected estimates of costs of service for APS's residential customers.

Q. How is your testimony organized?

A. Following this introduction, my testimony consists of five sections. Section 2 discusses why this proceeding is not the appropriate forum for consideration of Cost of Service Study (COSS) issues. Section 3 discusses why a COSS is the improper tool for evaluation of long-lived resource acquisitions. Section 4 addresses why the Commission should reject APS's proposal to create a new class for NEM customers. Section 5 summarizes APS's COSS, addresses the flawed assumptions related to the allocation factors used used by APS in its COSS, and presents TASC's recommended credits for NEM customers that should be applied to arrive at a net cost of service for NEM.

Q. Please summarize your recommendations and conclusions.

A. In its December 3, 2015 procedural order, the Commission requested that parties comment on the value and cost of solar, as well as the cost to serve customers both with and without distributed generation (DG). In response, APS chose to submit a COSS, in which APS claims that NEM customers currently pay far less than their cost of service

[1] In this testimony, all references to NEM customers relate to NEM customers in the residential customer class unless otherwise noted.

and proposes a dramatic restructuring of rates. However, this is a proceeding that is primarily concerned with the value and cost of DG; it is not a ratesetting proceeding. Thus, this proceeding is not the appropriate place to consider cost of service issues for specific utilities or to consider new rate proposals. Furthermore, APS's COSS contains clear flaws. The Commission should, therefore, note the flaws and issues raised by APS's COSS, but should delay making any final determinations regarding the COSS until APS's next general rate case.

Notwithstanding the fact that the Commission should not make any final determinations regarding APS's COSS in this proceeding, there are serious substantive shortcomings in APS's COSS in terms of its methodology and assumptions, making the APS COSS of little or no value to the Commission in its assessment of the value of solar.

First, APS's COSS simply ignores multiple aspects of DG value because APS has elected to view these new DG resources only on the basis of short-term costs and benefits. Since a COSS focuses on short-term cost issues, it is not the proper tool for evaluating new generation resources, whether they are traditional utility scale projects or DG. Any evaluation of DG resources must at least consider the potential value that is under consideration in this proceeding, such as potential avoided transmission and distribution capacity and accurate generation capacity and energy. The APS COSS simply assumes that NEM resources cannot avoid transmission or distribution costs. Therefore, APS's COSS provides little information about the long-run value of NEM resources. The Commission should give it no weight in assessing the long-run value of solar.

Second, APS recommends establishing a new customer class for residential customers who install DG systems and use NEM service. APS contends that NEM customers have different load shapes and different costs of service than other residential customers. Neither argument is persuasive. Although NEM customers may not have delivered load shapes that mimic those of the "average" residential customer, the same could be said for many other sets of customers that are currently in the residential customer class. By providing only a selective application of what APS means by "different load shapes" along with the fact that APS's COSS is unreliable, APS has not met its burden of proof for

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establishing a new customer class. The Commission should refuse to approve this proposal in this docket.

Third, APS has used flawed assumptions in its COSS when it tried to calculate both the cost of service for NEM customers as well the credits against the cost of service related to the value of solar generation (the difference between the estimated cost of service and the estimated credits being equal to the "net cost of service." APS has two options for how to develop the net cost of service for NEM customers: to base its COSS on delivered energy or to base its net COSS on gross household load less credits for energy generated by NEM customers. APS chose the latter approach but then incorrectly calculated the benefits of NEM by failing to account for the capacity value of solar put onto APS's distribution system and by using the incorrect allocator for demand costs.

I demonstrate that by using more appropriate credits for NEM generation, the net cost of service for NEM customers drops significantly. With these revised credits, the gap between revenue collected and net cost of service declines relative to APS's analysis. It is important to note that my analysis of net cost of service is conservative in that it assumes all solar systems are oriented toward the south (thereby underestimating the avoided demand credits). In addition, my net cost of service does not include any credit for certain important direct benefits provided by NEM customers (e.g., fuel hedging or market price mitigation) or any societal benefits (e.g., reduction in emissions and water use, improvements to the local economy) identified by TASC witness Mr. Beach in his opening testimony.

The Commission should defer consideration of APS's proposals to establish a new customer class for NEM customers as well as decisions about the reasonableness of APS's COSS until the next APS general rate case.

II. This Proceeding Is Not The Appropriate Place To Consider Cost Of Service Issues; This Topic Is Best Examined In General Rate Cases

Q. Why has TASC chosen to submit testimony related to APS's COSS in this docket?

A. APS submitted a COSS in this docket as requested by the Commission.[2] As a result, TASC felt that it was necessary to point out to the Commission the significant flaws in APS's COSS.

Q. Does TASC believe that this docket is the appropriate venue to examine cost-of-service issues or establishment of new rate classes?

A. No. APS is proposing a dramatic restructuring of rates through a detailed cost model that, in the current proceeding, can only be addressed on a highly expedited schedule. As a fundamental policy consideration, the rate proposal and underlying analysis deserves full examination in its own proceeding. The appropriate place to consider the inputs and structure of APS's COSS is in the APS general rate case, where cost-of-service issues are carefully vetted by all parties. Also, in a general rate case, the question of whether to establish new rate classes could be examined by all interested parties. That is not the case in this proceeding.

Q. Does APS's COSS submitted in this docket incorporate value of solar methodologies under development or other findings established in this proceeding?

A. No. APS explicitly refuses to incorporate in its COSS value that is unique to solar DG, such as transmission and distribution cost savings, or environmental and economic benefits; APS values solar only based on avoided generation demand and energy costs.[3]

Q. Are there other reasons to defer consideration of COSS issues until the next general rate case?

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[2] Docket No. E-00000J-14-0023, Procedural Order, December 3, 2015, p. 1 (setting testimony schedule regarding value and cost of DG as well as APS's cost of service for DG and non-DG customers).

[3] Direct Testimony of Leland R. Snook on behalf of Arizona Public Service Company (APS), Docket No. E-0000J-14-0023, February 25, 2016 (Snook Testimony), pp. 15-17.

A. Yes. There are obvious shortcomings in the basic COSS assumptions, which are detailed later in my testimony. The current schedule does not allow adequate time to propound discovery and to fully develop more proper inputs for the COSS. Even more importantly, APS was unable to provide intervenors with a fully functional COSS model in response to discovery. As a result, intervenors did not have an opportunity to perform alternative modeling runs to test the sensitivity and reasonableness of the APS COSS model.

Q. What actions do you recommend that the Commission take with regards to consideration of APS's COSS in this docket?

A. The Commission should note the flaws in the reasonableness of the APS COSS in this proceeding but delay making any final determinations regarding the COSS until APS's next general rate case. In addition, the Commission should also give no weight to APS's flawed COSS in the determination of the value of solar being determined in this docket. Instead, the Commission should rely on the value of solar analysis presented in this docket by TASC witness Mr. Beach.[4]

III. A COSS Does Not Accurately Assess The Validity of Resource Planning Decisions

Q. What does APS claim is the value of its COSS in this docket?

A. APS states that if NEM customers were hypothetically viewed as a separate customer class or sub-class, then NEM customers would only pay a small fraction of their cost of service as based on APS's COSS.[5]

Q. Is this a reasonable perspective?

A. No, it is not for two reasons. First, as discussed in the next sections, it is not reasonable to treat NEM customers as a separate rate class. APS provides no compelling data to show

[4] Direct Testimony of B. Thomas Beach on behalf of The Alliance for Solar Choice (TASC), Docket No. E-0000J-14-0023, February 25, 2016 (Beach Testimony).
[5] Snook Testimony, pp. 3-4.

that the usage characteristics of NEM customers are sufficiently different from a typical customer in the same class to warrant such a change. Second, looking exclusively at the COSS, is not a reasonable method to evaluate the value of solar. Customers make long-term investments when they decide to install solar on their homes. These long-term investments provide long-term benefits to APS, allowing it to avoid generation, transmission, and distribution costs for all customers (not just a subset of solar customers) over the lifetime of the solar panels. In addition to reducing the demands on APS's generation, transmission, and distribution systems for existing customers, NEM customers also export power to the APS distribution system. These exports from NEM customers to the distribution grid provide APS with additional long-term power supplies dispersed throughout APS's service territory.

Q. Does APS's COSS account for these long-run benefits of NEM?

A. No. Those long-run benefits are ignored in APS's COSS since the COSS focuses only on a single historic test year. APS notes that "[i]n a COSS, the tangible benefits in the study period of rooftop solar are included" and that a value of solar analysis "does not look at actual costs, and is fundamentally different than a COSS. It involves predicting the marginal benefits of solar over the next 20 or 25 years, and often includes both operation and societal benefits."[6]

Q. Would APS's COSS be a reasonable tool to use to evaluate the reasonableness of other long-run resource investments?

A. No. A single-year snapshot of the costs and benefits of a long-run resource is clearly unreasonable. It is highly unlikely that APS would use such an approach to evaluate the cost-effectiveness of other long-run resource options.

[6] Snook Testimony, p. 29.

Q. Can you provide an example?

A. Yes. Assume that APS is considering developing a new APS-owned generating facility. The fixed costs of that new generating facility are not equal over time. Rather, the fixed costs are front-loaded and decline over the life of the project. It would be unreasonable to examine the reasonableness of such a long-term investment using a one-year snapshot, especially since the costs and benefits of the generation facility would change significantly over time. Similarly, the long-run benefits and costs of NEM will evolve over time, making a snapshot view of the impacts of NEM almost meaningless.

Q. What do you conclude from this?

A. The COSS submitted by APS in this docket provides little information about the long-run value of NEM resources and the Commission should give it no weight in assessing the value to all customers of long-term solar investments by NEM customers.

IV. APS Does Not Provide Compelling Evidence Justifying the Need For A New Class For NEM Customers

Q. Does APS recommend that NEM customers be assigned to a separate class?

A. Yes. APS proposes to establish a separate customer class for residential NEM customers that is distinct from the existing residential customer class, claiming that NEM customers have very different costs of service and load characteristics.[7]

Q. How do you respond to APS's claim that NEM customers have very different costs of service?

A. As discussed in the next section of this testimony, APS's COSS is fraught with methodological problems and improper assumptions. These problems include:

[7] Snook Testimony, pp. 11,12.

- assuming that generation from NEM customers do not avoid any transmission or distribution demand costs;
- allocating demand costs for distribution substation and primary distribution using the incorrect allocator; and
- ignoring the generation demand reductions associated with NEM deliveries to the distribution grid.

Because of these modeling problems, the Commission should give no weight to recommendations from APS regarding the need for a new customer class based on its COSS.

Q. How do you respond to APS's claims that NEM customers have very different load patterns and, as a result, should be placed in a separate rate class?

A. There is no question that NEM customers do not have delivered load shapes that mimic those of the "average" residential customer. However, the same could be said for many other sets of customers that are currently in the residential customer class. There are significant variations in load shapes, both among customers with similar end uses in their residences, and between customers that have installed various load-modifying technologies in their homes. Despite this, APS does not appear to be moving to create separate customer sub-classes for these other groups of customers, only NEM customers.

Q. Has APS demonstrated that the loads characteristics of NEM customers are outside the range of load variation that is seen within the residential class?

A. No. APS uses selected examples of customer classes to try to demonstrate this. However, APS only focuses on the average of all of those customers, not on the range of loads shown by those customers. As a result, APS's analysis does not provide compelling evidence that NEM customers are well outside of normal variation in loads seen in the residential class.

Q. How do you respond to APS's claims that residential customers on energy efficiency programs have "a load shape that is very similar to the average APS residential customer."[8]

A. APS witness Mr. Snook's "load shape" for customers that participate in APS's energy efficiency program consists of a single summer and a single winter day for "residential customers participating in the following measures: CFLs, duct test and repair (AC) and conservation behavior."[9] This is a very limited subset of possible energy efficiency measures. For example, APS witness Mr. Snook ignores customers that install smart thermostats to control air conditioner loads. Such a technology would clearly have a different load shape on a summer day than would a typical customer without a smart thermostat, likely resulting in much lower usage during daytime hours, and somewhat greater usage in the evening hours.[10] In fact, APS even has a demand response program that takes advantage of smart thermostats.[11]

Q. Can you demonstrate the changes in load shape that other behind-the-meter technologies cause to customer's load shapes?

A. I had hoped to provide the Commission with information about how different behind-the-meter technologies result in significant changes to the "typical" load shape for APS's residential customers. Unfortunately, APS refused to provide hourly load data to allow for this analysis.[12] However, there is little doubt that those different subsets of customers would have hourly load shapes that differ from the "typical" residential customer.

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[8] Snook Testimony, p. 24.

[9] Snook Testimony, Figures 4 and 5, pp. 26-27.

[10] There might also be significant differences in usage patterns among customers with similar end-use controls. Consider a house with a setback thermostat. If the thermostat's batteries fail, then the thermostat will likely not set the customer's thermostat to a higher setpoint during the day, meaning that the customer would have a higher electric demand than otherwise expected based on the delivered load of a typical customer with a setback thermostat.

[11] APS offers business customers the "Peak Solutions" program, which controls smart thermostats. https://www.aps.com/en/business/savemoney/solutionsbyequipmenttype/Pages/thermostats-and-energy-controls.aspx

[12] See APS's Supplemental Response to TASC Data Request 4.1 (See Exhibit WAM-2). It is surprising that APS was unable to provide hourly load data for the subset of customers that are participants in APS's energy efficiency or demand response programs since APS seems capable of developing average hourly loads for at least two months for a subset of customers that have installed certain energy efficiency measures (see Snook Testimony, Figures 4 and 5, pp. 26-27). In addition, APS claimed that it was unable to provide hourly load data for apartment customers.

Q. Were you able to find studies with actual residential load data illustrating the impact energy efficiency programs (including smart thermostats) have on load profiles?

A. I was not able to find studies which included actual residential load data, but there are several studies which simulated various residential energy scenarios. The National Renewable Energy Laboratory's (NREL) Integrated Energy System Model (IESM) analyzes the impact so-called Home Energy Management Systems (HEMS). These are systems which, among other things, control household temperature. Depending on the setup, these HEMS can be quite complicated, communicating in real time with the grid to determine the optimal time to operate the household appliances. NREL's IESM is "designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure."[13]

A June 2015 study simulated 20 HEMS-equipped houses on a single distribution feeder in the state of North Carolina during the month of July. The feeder is populated with 20 well-insulated houses, all connected through four 25 kVA single-phase, center-tapped transformers.[14] The desired temperature is dictated by the EPA's Energy Star recommendations.[15] The figure below shows the impact of three different HEMS penetrations (0%, 50% and 100%):

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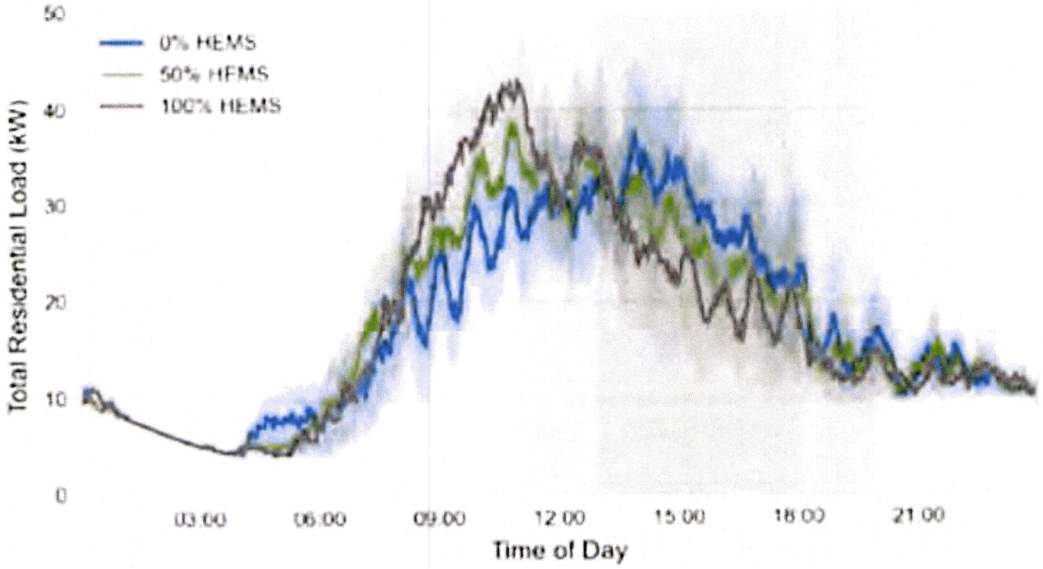
customers that use dual fuels, or seasonal customers. This is also surprising since Figures 4 and 5 of Mr. Snook's testimony appears to present average hourly loads for January and July for those customers.

[13] Ruth, Mark, Annabelle Pratt, Monte Lunacek, Saurabh Mittal, Hongyu Wu, and Wesley Jones. "Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the *23rd International Conference on Electricity Distribution*, Lyon, France, June 15-18, 2015 (NREL 2015), p. 2 (See Exhibit WAM-4). Also available at http://www.nrel.gov/docs/fy15osti/63500.pdf

[14] NREL 2015, p. 2 (See Exhibit WAM-4).

[15] Energy Star: Program Requirements for Programmable Thermostats," p. 7 (See Exhibit WAM-5). Accessed April 5, 2016. Also available at: https://www.energystar.gov/ia/partners/prod_development/revisions/downloads/thermostats/ProgramThermDraft1.pdf?0b55-1475.

Figure 1: Load Profiles of Various Levels of Home Energy Management Systems Penetration



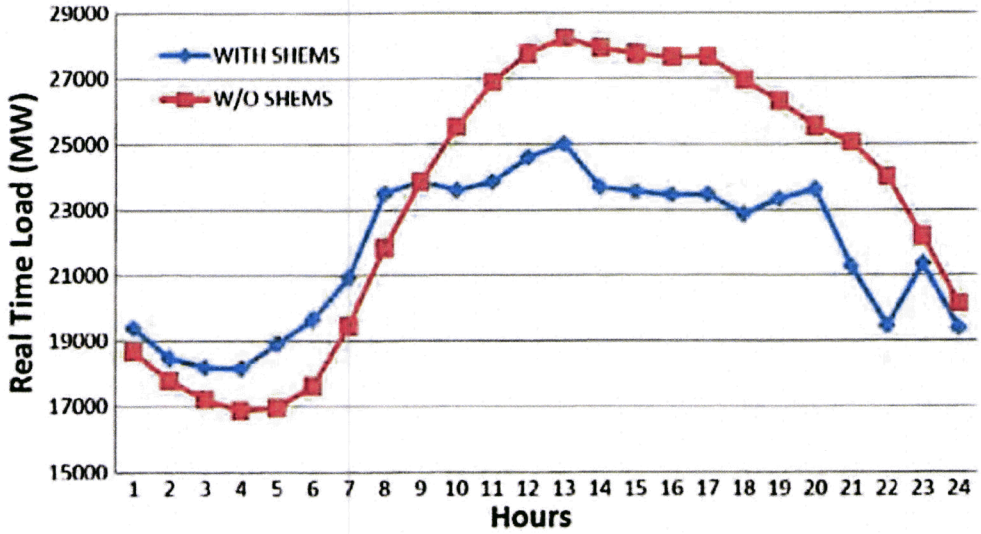
Source: NREL 2015 p. 4 (See Exhibit WAM-4).

Under a simulated time-of-use tariff, the presence of HEMS shifts customer load to earlier in the day, when electricity prices are less expensive.[16] The highest HEMS penetration results in the lowest load during the maximum pricing period (darkest grey shaded portion).

A December 2013 paper studied the impact of HEMS on a randomly selected day in the New York ISO region. Different than NREL's IESM, the HEMS in this study was designed to collect real time pricing data and customer preferences/activities to optimize the electricity load. Residential energy consumption (including washer/dryers, heating/air conditioning, water heating and electric vehicle charging) was simulated to investigate how HEMS shifts load curves. The results are shown in the figure below.

[16] NREL 2015 p. 3 (See Exhibit WAM-4).

Figure 2: Load Curves With and Without Home Energy Management Systems



Source: Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." *IEEE Transactions on Smart Grid* 4, no. 4 (December 2013): 1878–87. doi:10.1109/TSG.2013.2258181. (IEEE 2013), p. 1886 (p.9 of pdf) (See Exhibit WAM-6).

Not only do HEMS shift load to earlier in the day (the HEMS profile is higher between 1:00 and 6:00 am), but they "reduce the loads in peak hours by nearly 10 percent which is significant."[17]

Q. Has APS proposed to establish different rate classes for residential customers with these various behind-the-meter load modifying equipment?

A. I am not aware of APS making such a proposal. Such a proposal could prove to be administratively burdensome. I understand that Staff does not support the creation of a multitude of customer classes based on the end-use modifying technologies that a customers have,[18] stating that it "concludes it is best if utility rates are designed to be neutral, agnostic, and unbiased toward the technology and lifestyle choices of customers."[19]

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[17] IEEE 2013, p. 1885 (p.8 of pdf) (See Exhibit WAM-6).
[18] Direct Testimony of Thomas M. Broderick, Docket No. E-04204A-15-0142, December 9, 2015 (Broderick Testimony), pp. 6-7; Direct Testimony of Eric Van Epps, Docket No. E-01575A-15-0312, March 18, 2016, pp. 2, 10.
[19] Broderick Testimony, pp. 6-7.

Q. What do you conclude regarding APS's claim that NEM customers should be in a separate customer class because of their different load shapes?

A. APS is being selective in its application of what it means by "different load shapes." When residential customers employ various behind-the-meter technologies, they have load shapes that are "different" than the average load shape in the same way that NEM customers have delivered loads that are "different." Because of this and because APS's COSS is unreliable, I do not believe that APS has met its burden of proof regarding the need to establish a new customer class for NEM customers and, as a result, the Commission should reject APS's proposal.

V. APS'S COSS Is Flawed And Should Be Given No Weight

Q. What is the purpose of this section?

A. This section summarizes APS's COSS assumptions and modeling approach and identifies significant flaws with the COSS.

A. APS's COSS Model and Assumptions

Q. What are APS's key proposals in this proceeding regarding cost of service issues?

A. As discussed above, APS proposes to establish a separate customer class for residential NEM customers that is distinct from the existing residential customer class, claiming that NEM customers have very different costs of service and load characteristics.[20] Because of these claimed differences, APS recommends that NEM customers be assigned to a separate customer class than other customers.

In addition to assigning NEM customers to a different customer class than other residential customers, APS also supports use of a three-part tariff for NEM customers.[21] This tariff would have a large basic service fee, a large non-coincident demand charge, and a relatively small energy charge.

[20] Snook Testimony, pp. 11,12.
[21] Snook Testimony, p. 27.

To support its proposal, APS provides, among other things, a COSS. In this COSS, APS proposes to use the gross electricity usage by NEM customers[22] instead of the actual electricity delivered by APS as a key billing determinant.[23]

Q. Does APS deliver energy to a NEM customer to meet the customer's gross electric load?

A. Not at all times of the day. TASC witness Mr. Beach's opening testimony in this docket summarizes the three different delivery periods for NEM customers.[24] As shown in Mr. Beach's testimony, when the NEM customer's solar system is not generating, APS delivers energy to meet the customer's entire electric load. However, at other times of the day, APS deliveries only supply a fraction of the customer's electric load, with the rest of the load being met by the NEM customer's solar system. If the solar system is generating less than the customer's gross electric load, then the solar system acts exactly like energy efficiency, reducing the energy delivered at that time by APS. Finally, in other hours, the customer's solar system generates more electricity than the customer can use onsite at that time, resulting in deliveries of electricity to the APS distribution system. APS takes possession of the power delivered by the NEM customer to the APS distribution system at the NEM customer's meter and the power is used by APS to meet demands by other customers on the distribution feeder.

Q. How does APS account for energy that a NEM customer generates in its COSS?

A. APS claims that it models generation from NEM customers by crediting the customer for self-provided capacity and for energy that is both consumed onsite and exported to the APS grid.[25] APS values this energy at its posted tariff for excess sales from NEM customers, Schedule EPR-6[26], which APS witness Mr. Snook characterizes as avoided

[22] APS calls this the "site load."
[23] Snook Testimony, p. 15.
[24] Beach Testimony, p. 11.
[25] Snook Testimony, p. 15.
[26] APS Response to Vote Solar Data Request 2.3, p. 1 of 2 (See Exhibit WAM-3), which refers to APS15773.

fuel costs.[27] It then reduces the cost of service for the solar customers based on this value.[28] APS also provides a 19% production demand credit.[29]

Q. Does APS claim that its proposed approach to developing allocators for residential NEM customer generation fully credits NEM customers for the benefits that they provide to the grid?

A. Yes. APS states that "[t]his approach fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid by their rooftop solar systems."[30]

Q. Does the credit APS assigned to residential rooftop solar generation in its COSS include the value of benefits that these resources provide to its transmission and distribution system?

A. No. APS states that its COSS methodology "did not include savings for transmission or distribution costs, nor did it include environmental or economic development benefits."[31]

Q. Why does APS believe that ignoring these two benefits in its credit calculation results in a credit that is fully compensating NEM customers?

A. APS argues that "the 2014 data make clear that customers with rooftop solar which was installed without regard to location did not cause any transmission and distribution savings."[32]

Q. Please describe the assumptions used by APS to develop the credits for energy produced by the NEM customers.

A. APS's credit is equal to the energy generated by the NEM customers (270,312 MWh at the customer level) multiplied by the non-time-differentiated price for non-firm power under Schedule EPR-6 ($0.02895 per kWh).[33]

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[27] Snook Testimony, p. 17.
[28] Snook Testimony, pp. 15-16.
[29] Snook Testimony, p. 16.
[30] Snook Testimony, pp. 15-16.
[31] Snook Testimony, p. 17.
[32] Snook Testimony, p. 18.

Q. Does this approach under-value the energy produced by NEM customers?

A. Yes. Using a non-time-differentiated price for the energy credit under-values the energy produced by the NEM customer since solar generation occurs during daylight hours, which is when the value of energy is higher than at night.

Q. How are you sure that the energy credit is based on the total generation by the NEM customer's system?

A. APS provided a workpaper that presented the total generation by NEM customers. The values from that workpaper matched the total solar generation amount shown in APS's workpaper supporting the calculation of the energy credit, which was provided in response to Vote Solar Data Request 2.3.[34]

Q. Please describe the assumptions used by APS to develop the credits for generation demand.

A. APS uses a different approach to calculate the generation demand credit than it uses to calculate the energy credit. APS calculates the generation demand credit by averaging the percentage change in (1) the change in Coincident Peak Demand averaged over the months of June-September between Solar Site and Delivered loads and (2) the change in Class Non-Coincident Peak (On-Peak) averaged over the months of June-September between Solar Site and Delivered Coincident Peak Demand averaged over the months of June-September for Solar Site and Delivered and Delivered loads. **Table 1** presents this calculation for NEM customers taking service under APS's Energy Rate option.

Table 1: APS's Derivation of Generation Demand Credit

Month	Coincident Peak (MW)		Class NCP (On-Peak) (MW)	
	Delivered	Site	Delivered	Site
June	76.5	104.1	93.4	104.8
July	94.9	122.5	111.3	122.5

[33] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 1 of 37 (See Exhibit WAM-3).

[34] See Response to Vote Solar Data Request 1.1, file "Allocation Factors (TYE 12312014), APS15746.xlsx", tab "Input," cells D173 and D177, a copy of which is presented in Exhibit WAM-3. Note that these cells are labeled in part "Total Solar Generation" or "Solar Generation."

August	93.2	119.8	94.2	105.1
September	60.0	103.8	99.2	107.1
Average	81.2	112.6	99.5	109.9
Relationship – Delivery versus Site		27.90%		9.42%
Peak 2 Point Average				**18.66%**

Source: APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 2 of 37 (Exhibit WAM-3)

Q. Does this calculation provide a generation demand credit for generation that NEM customers deliver to the distribution system?

A. No. This calculation only provides a generation demand credit based on the difference between the Solar Site Electricity and the Delivered Electricity. APS provided definitions of these terms:

- Solar Site Electricity is equal to [Delivered Electricity + (Produced Electricity – Received Electricity)];
- Delivered Electricity is measured energy delivered from APS to customers; and
- Received Electricity is energy delivered from the customer to APS.[35]

From this, it is clear that Solar Site Electricity less Delivered Electricity is equal to Produced Electricity – Received Electricity, meaning that APS's generation demand credit is not based on total Produced Electricity but on energy used directly by the NEM customer. This means that APS's method does not provide a generation demand credit for Received Electricity.

Q. Is this the only flaw in APS's COSS modeling?

A. No. The following sections discuss the overall flaws in the APS COSS modeling and certain specific errors in the assumptions used in the COSS.

[35] See APS Response to Vote Solar Data Request 2.4, provided in Exhibit WAM-3.

B. APS's Overall COSS Modeling Approach Has Serious Flaws

Q. Did APS use a reasonable approach for determining the net costs to serve NEM customers in its COSS?

A. There are two ways that APS could have properly determined the net costs to serve NEM customers. One way would be to develop cost allocators for NEM customers in the COSS based on the load and peak demands associated with electricity delivered by APS and then to develop a credit associated with excess energy delivered by NEM customers to the APS distribution grid. The other way would be to calculate NEM customers' cost of service based on their gross load and then to develop credits for avoided generation, transmission, and distribution demand costs and avoided energy costs based on the entire output from the NEM customers' solar systems. Instead, APS used a flawed hybrid approach: it used the gross electric usage of NEM customers (i.e., delivered load plus solar generation used behind the meter by the NEM customer) in its COSS but then failed to provide the appropriate credits for NEM customers' solar generation by (1) failing to account for excess energy delivered by the NEM customers to the distribution grid and (2) simply ignoring the costs that NEM customers avoid on the transmission and distribution systems.

Q. Please explain.

A. APS is not fully accounting for the benefits NEM customers provide in developing its COSS. It is explicitly omitting several of the value categories that NEM customers provide and which are actively being contemplated in this proceeding. As discussed elsewhere, using the proper allocators for distribution substations and primary wires reduces the distribution demand costs that should be allocated to residential NEM customers. Also, APS does not provide any credit for avoided generation demand associated with generation that NEM customers deliver to the distribution system. Given that the very purpose of this proceeding is to establish the value of solar and methodologies for quantifying it, it seems premature to file a cost study that has already determined the value of solar to be zero.

Q. Does evidence from other utilities demonstrate that distributed generation can potentially reduce transmission and distribution infrastructure costs?

A. Yes, Pacific Gas & Electric recently stated that a flattening of its load forecast due to energy efficiency and rooftop solar has eliminated the need for $200 million of sub-transmission projects, which were recently eliminated in the California Independent System Operator's 2015-2016 Transmission Plan.[36]

Q. What other factors should be taken into account in considering the impact of solar PV generation on distribution costs?

A. A variety of factors influence the overall impact of solar PV on system and distribution feeder capacity. It is worth noting that distributed solar PV is typically not a single resource, but many small resources. For this reason, although the average output of any given system is intermittent, it is very unlikely that a significant portion of the overall resource fleet has a forced outage (i.e., is unavailable due to maintenance or technical problems) at any given time. Thus, availability of the resource is likely quite high. Additionally, geographic diversity, even over a relatively small area, could in some cases make the overall solar PV resource much more reliable than a single system on even a partly cloudy day by averaging the intermittency across the entire area.

Q. How could these nuances of distributed generation resources be better taken into account in order to provide APS with benefits such as avoided transmission and distribution investments?

A. By considering distributed generation more carefully in the transmission and distribution planning process, cost savings could be realized more readily. For example, not only could a detailed review of fleet-wide resource reliability yield greater insight into potential opportunities to avoid certain distribution investments, but this type of analysis could facilitate an ongoing two-way process. Once it has a comprehensive view of how distributed generation impacts the system and might create savings, APS could engage in more proactive resource planning where it incentivizes customers to install, for example, solar PV in locations and with orientations that create the most benefit. Such an approach

[36] California Energy Markets. *Cal-ISO Board Approves Annual Transmission Plan*. Issue No. 1379, p. 10. April 1, 2016 (See Exhibit WAM-7).

could maximize factors like geographic diversity and timing of peak solar output. Rather than being unexpected, distributed generation would be a part of APS's overall plan.

Q. What does APS's assumption regarding valuing generation from a NEM customer's solar system at avoided costs assume about the ability of NEM customers to avoid usage of APS's transmission and distribution system to serve NEM customers?

A. APS's narrow view of avoided costs only considers avoided costs for generation demand and energy.[37] As a result, the credits that APS uses in its COSS to account for the value of solar supplied by NEM customers explicitly assumes away any potential benefits of the solar generation on costs for providing transmission or distribution service. This is clearly unreasonable.

Q. Why is this unreasonable?

A. By assuming that all NEM customers' solar systems do not reduce demands on the APS distribution system, APS effectively assumes that all solar systems owned by NEM customers on each distribution feeder fail to generate at precisely the same moment, essentially requiring standby service. This is not a reasonable assumption given the geographic diversity and high reliability of photovoltaic systems during daylight hours.

Q. Is it reasonable to ignore the impact of the energy that NEM customers inject onto the system when their generation exceeds their load?

A. No. This power is consumed by other customers on the distribution system; it is not fed back onto the transmission system through the interconnection between the transmission and distribution systems.[38] As such, it reduces the loads that APS must serve on the feeder upon which the NEM customer is located or on another part of the distribution system. Thus, it effectively reduces the cost to serve other residential customers on the distribution system by reducing loading on the interconnection between the transmission and distribution systems as well as the distribution substations and primary wires. It also reduces loading on the transmission system for those customers. Finally, it reduces the amount of generation that APS must supply to those customers. For that reason, it would

[37] Snook Testimony, pp. 15-17.
[38] See APS Response to TASC Data Request 4.4 (See Exhibit WAM-2).

not be reasonable to ignore the impact of excess NEM generation in determining the net cost of service for NEM customers.

Q. What would be the effect of changing this assumption?

A. By properly crediting the value of excess generation from NEM customers to the solar customer class, the cost of service for those customers will be reduced relative to the cost of service estimated by APS.

Q. Have you developed an estimate for this benefit?

A. Yes. My estimated credits discussed below account for both solar energy that is used by NEM customers onsite as well as energy that NEM customers inject onto the distribution system.

Q. What do you recommend?

A. APS's COSS cannot be used to develop the appropriate cost of service based on delivered loads. Therefore, I was unable to develop estimates of the actual cost to serve NEM customers based on delivered load plus a credit for deliveries of excess generation to the APS distribution grid. As a result, I develop alternate estimates of the various costs avoided by NEM customers. These credits are much larger than those developed by APS.

C. APS Relies on Flawed Assumptions in Its COSS

Q. What is the purpose of this section of your testimony?

A. This section identifies various flawed assumptions used by APS in its COSS. The use of these flawed assumptions renders the results of APS's COSS meaningless with respect to valuing NEM customers. The flawed assumptions described below are:

1. Allocating costs based on gross load instead of delivered load overstates allocation of distribution costs to the hypothetical NEM class; and
2. Allocating costs based on non-coincident peak overstates allocation of certain infrastructure (i.e., primary distribution and distribution substation) to NEM customers.

1. APS Unfairly Uses Different Billing Determinants To Allocate Costs To NEM Customers

Q. What are the specific allocators that APS uses to allocate generation and distribution demand costs to different customer classes?

A. APS uses the Average and Excess allocator to allocate generation demand costs to customers. APS uses Non-Coincident Peak Loads for customers to allocate demand costs for distribution substations and primary distribution lines. APS uses the Sum of Individual Max demands to allocate demand costs of distribution transformers and secondary distribution lines.[39]

Q. How does APS develop these allocators for its non-NEM customers?

A. APS uses metered loads to develop allocators for its COSS.[40] This is the approach that APS has historically used to allocate demand costs to residential (and other) customers.

Q. Does APS propose to use metered loads to develop the allocators for residential NEM customers?

A. APS uses the NEM customer's gross load at the home (i.e., load served both by APS and the customer's rooftop solar system) as the starting point for cost allocations to develop the Coincident Peak (CP), the Non-coincident Peak (NCP) and the Sum of Individual Max demand allocators.[41]

Q. Is APS's proposed approach to developing allocators for residential NEM customers based on a historical approved methodology specific to NEM customers?

A. No. APS is proposing a new sub-class of residential customers and is therefore proposing a new methodology for residential NEM customers.[42]

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[39] Snook Testimony, p. 11.
[40] Snook Testimony, p. 11.
[41] Snook Testimony, p. 15.
[42] Snook Testimony, pp. 11-12.

Q. Why does APS use different methodologies for incorporating loads for NEM and non-NEM customers into its COSS?

A. APS appears to believe that it must account for load that would have materialized had the customer not installed solar DG, and then credit the customer for DG after the fact. APS does not justify why it chose this relatively complicated approach rather than simply using metered load.

Q. Is this approach reasonable?

A. It is one way to attempt to measure the net costs that NEM customers impose on the APS system. However, as discussed below, APS chooses to ignore at least one component of avoided costs in its application of this approach. For this reason, APS's estimates overstate the costs to serve NEM customers.

Q. Does APS use a similar approach for allocation of costs to other residential customers that modify their delivered loads by installing technology behind-the-meter?

A. No. Despite the fact that customers can and do install energy efficiency measures, participate in demand response programs, or install appliances that do not use electricity to serve end-uses that other APS customers serve using electricity and that these measures result in changes in their demands on the distribution system, APS uses the metered load as the basis for allocating distribution costs for those customers. In other words, APS reduces cost allocation to non-NEM customers for reducing demands on the distribution system through load modifications using behind-the-meter technology.

Q. What would be the impact if APS were to use the metered loads for NEM customers to derive the billing determinants used in the COSS instead of the derived loadshape that it is proposing to use?

A. Using metered loads for the residential solar customers would likely reduce the distribution demand costs that are allocated to those customers. This would reduce the difference in the COSS between revenues collected through rates and the revenue requirements for the residential NEM class as constructed by APS.

Q. Have you estimated the impact on the COSS of your proposed change in allocators?

A. I attempted to estimate the impacts of revising the cost allocators and billing determinants used in APS's COSS but was unable to do so because APS's "working" COSS model was not fully functional.[43] As a result, I develop estimates of credits that should be applied against the costs to serve NEM customers to arrive at the net cost of service for those customers.

2. Use Of NCP To Allocate Substation and Primary Distribution Costs Is Incorrect

Q. Is the use of NCP for NEM and non-NEM customers reasonable for allocation of distribution demand costs?

A. APS's own data shows that its loads on a representative sample of distribution feeders are highly correlated with system peak demands and are not randomly distributed. The following figure presents the loads on 8 representative feeders by month (colored lines). Also shown in these figures is APS's system peak load (black dashed line).[44]

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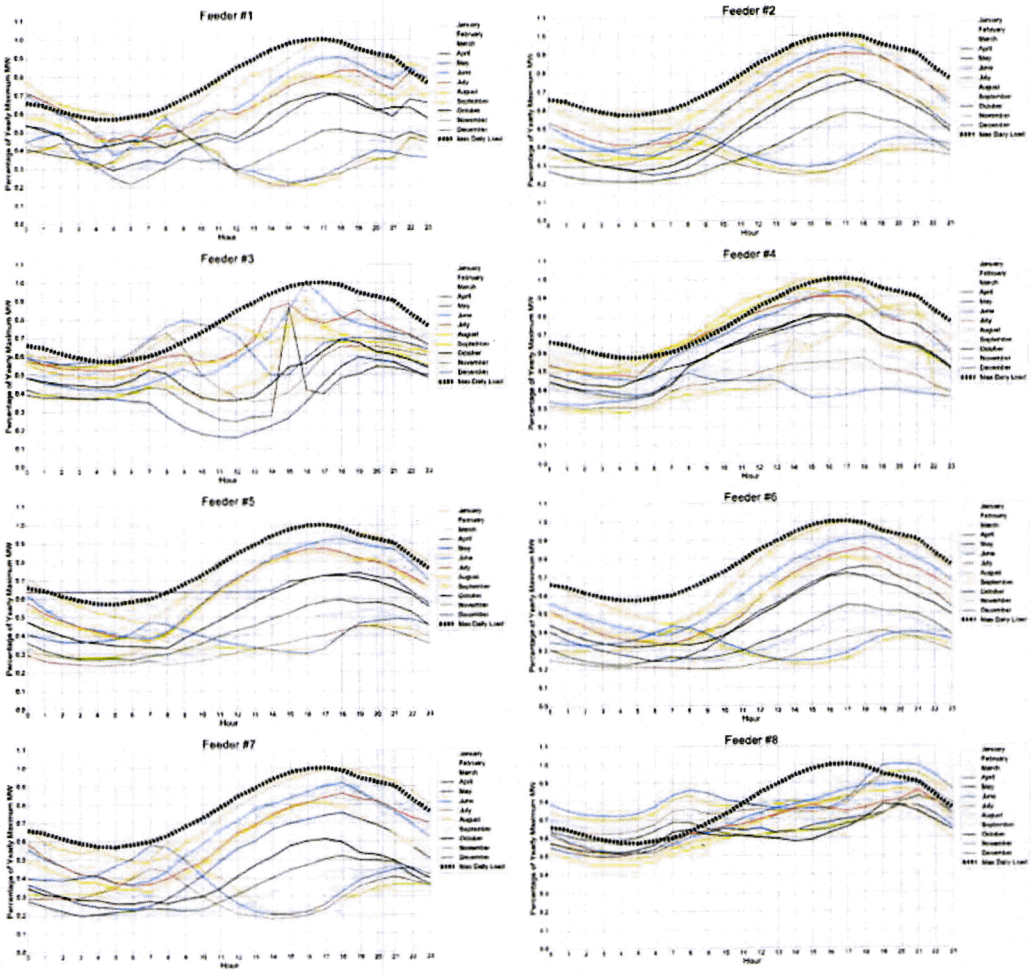
[43] APS's "working" model was not linked to the model that APS claims was used to develop the billing determinants and allocation factors that are used in the COSS. The data structure for inputs to the "working" model was very different than the data structure for the outputs from the "allocation factor" model. As such, it was not possible to use the "working" model to examine the impact of different allocation factors or billing determinants on the cost of service for NEM customers.

[44] These figures present the hourly load on each feeder on the day with the maximum demand for each month, normalized using the maximum feeder loading for the year. Data based on APS Response to TASC Data Request 1.15, which is presented in Exhibit WAM-2.

Supplemental WAM

and APS Response to TASC Data Request 2.1b WAM

1 **Figure 3: Normalized Hourly Loading on Representative Feeders**



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4 **Q. How were these figures[45] developed?**

5 A. For each representative feeder, the maximum daily load for each month was normalized.
6 I determined the maximum annual loading on each feeder and the day of each month with
7 the monthly maximum loading of that feeder. I then normalized each hourly load for the
8 12 peak days by the annual maximum loading. Similarly, the maximum load (dashed

[45] See Exhibit WAM-8 for larger versions of these figures.

black line) is the hourly load of the day with the highest demand of the year divided by the maximum peak hour demand for the year.

Additionally, there were five anomalous days (**Table 2**) that were smoothed by averaging the hourly value of the previous day and the next day.

Table 2: Anomalous Days

Feeder	Month	Day	Hours Smoothed
3	April	14	14, 15
3	April	15	11
3	April	16	11, 12, 13, 14
8	May	18	11
8	May	19	11

Q. Please discuss your conclusions from these figures.

A. As seen from these figures, it is clear that during the summer months, which is when APS's system demands peak, there is a high coincidence between APS's loads and the loads on these representative feeders. Maximum monthly demand for Feeders 1, 2, 4, 5, 6 and 7 occurs in August between 3:00 and 6:00 pm. The maximum daily load (also occurring in August) peaks at 5:00 pm. Thus, use of NCP is not the appropriate allocator to use for allocating APS's distribution demand charges and the appropriate allocator is the coincident peak demand.

Q. What portion of the APS distribution system is loaded consistent with the figures shown above?

A. The loading on the feeders shown in the figures is the load that is delivered from the APS transmission system to the feeders through the distribution substations and over the primary distribution lines. From these figures it is clear that the loading of the distribution substations and primary distribution lines is coincident with peak demand.

Q. What is the more appropriate allocator to use for distribution demand costs related to distribution substations and primary distribution lines?

A. For these components of the distribution system, it would be more appropriate to use a cost allocator for generation and transmission demand costs instead of NCP.

Q. What would be the impact if APS were to allocate primary wires and distribution substation costs based on the same allocator as used for generation demand?

A. If the actual metered loads for solar customers were used in the allocation process, there would be a reduction in substation and primary wire-related distribution costs allocated to residential solar customers. This would reduce the difference in the COSS between revenues collected through rates and the revenue requirements for the residential solar class as constructed by APS.

Q. Have you estimated the impact of your recommended allocator on the COSS?

A. No. As noted above, APS's "working" COSS model could not be used to apply different sets of billing determinants or allocators to determine the cost of service for NEM customers. As a result, I developed a credit for avoided distribution costs as discussed below.

D. Revised Credits and Estimates Of Net Cost Of Service for NEM Customers

Q. What is the purpose of this section?

A. This section presents estimates of credits that should be netted against APS's cost of service estimates based on gross loads for NEM customers to arrive at the proper level of net cost of service for these customers. These credits differ from and are greater than the credits used by APS.

Q. Do you present credits for environmental impacts or other externalities?

A. While such credits are appropriately considered in a value of solar study (as discussed in Mr. Beach's testimony), I do not include those estimates here.

Q. How did you develop your recommended credits?

A. I used the Peak Capacity Allocation Factors (PCAFs) to determine the portion of primary distribution and distribution substation costs that are avoided by NEM customers.[46]

Q. Have others used a similar approach to determine cost responsibility or avoided costs for generation, transmission, and distribution demand costs?

A. Yes. As described by TASC witness Mr. Beach, the California Public Utilities Commission's Public Model, which was used to determine the cost-effectiveness of NEM resources, used PCAFs.[47] In addition, Pacific Gas & Electric (PG&E) allocates different parts of the costs of its distribution system using two different allocators. PG&E allocates primary distribution costs via PCAFs (which are similar to coincident demand) and allocates secondary distribution costs and new business on primary distribution costs based on FLTs (final line transformer loads, which are similar to non-coincident demand). PG&E does this by division (i.e., there's a separate marginal cost for each of these items for each division; each rate schedule gets a weighted average cost based on the amount of PCAF/FLT load in each division in that rate schedule.) PG&E describes this process as follows:

> The substation-level PCAF-weighted loads are weather-normalized weighted loads that indicate what contribution a class has made to a substation's peak. These PCAF-weighted loads are then summarized by division for the calculation of primary demand-related marginal cost revenue.
>
> FLT loads are either the class' diversified non-coincident demand at the FLT (residential and small commercial classes) or the class' undiversified non-coincident demand at the FLT (all other classes). Non-coincident demand is the class' highest observed demand during the year. As more than one residential or small commercial customer are served by a FLT, the FLT loads for these classes are scaled down (diversified) to reflect the fact that not all the customers served by that transformer will be operating at the time the FLT reaches its peak. For all the other classes, PG&E assumes that there is one customer per FLT.[48]

[46] For this analysis, I did not include any other direct benefits of solar, such as fuel hedging or market price mitigation. See Beach Testimony, Exhibit 2, pp. 9-11.
[47] Beach Testimony, Exhibit 2, pp. 1, 12
[48] "Pacific Gas and Electric Company, 2014 General Rate Case Phase II, Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design," Application 13-04-012, p. 2-8. (See Exhibit WAM-9).

This approach has been approved by the California Public Utilities Commission.[49]

Q. Has TASC developed PCAFs for allocation of demand costs in this proceeding?

A. Yes. TASC witness Mr. Beach developed PCAFs in support of his estimates of the value of solar in this docket.[50] Mr. Beach used the PCAFs to estimate the generation, transmission, and distribution demand costs avoided by NEM customers. Those same PCAFs are applicable here. These are presented below in **Table 3**.

Table 3: TASC-Recommended Demand Credits vs. Credits Proposed by APS

	Generation Demand	Transmission Demand	Distribution Demand (Substation/ Primary Distribution)	Distribution Demand (Secondary/ Transformer)
APS (Energy Rates)[51]	18.66%	N/A	N/A	N/A
APS (Demand Rates)[52]	14.64%	N/A	N/A	N/A
TASC (South-Facing)[53]	36.2%	36.2%	36.2%	20.1%
TASC (West Facing)[54]	53.21%	53.21%	53.21%	36%

Q. Has TASC developed revised energy credit rates?

A. Yes. TASC witness Mr. Beach has estimated that APS's avoided energy costs for solar DG as 4.215 cents per kWh for 2016.[55] I have used this value to assign energy credits to residential solar customers, as opposed to APS's 2.895 cents per kWh.[56]

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[49] The California Public Utilities Commission ultimately approved a settlement agreement using PCAF-based marginal distribution cost allocation factors: California Public Utilities Commission, D.15-08-005, *Decision Adopting Eight Settlements and Resolving Contest Issues Related to Pacific Gas and Electric Company's Electric Marginal Costs, Revenue Allocation, and Rate Design*, August 18, 2015 (See Exhibit WAM-10). *See also*: California Public Utilities Commission, A.13-04-012, *Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case*, Appendix A, July 16, 2014. (See Exhibit WAM-11).

[50] Beach Testimony, Exhibit 2, pp. 11-15.

[51] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.2 of 37 (Exhibit WAM-3).

[52] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.2 of 37 (Exhibit WAM-3).

[53] Beach Testimony, Exhibit 2, p. 12.

[54] Beach Testimony, Exhibit 2, p. 12.

[55] Beach Workpaper "Avoided Energy and Social Costs.xlsx," tab "Energy & Societal" Cell Q9

[56] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.1 of 37 (Exhibit WAM-3).

Q. What would be the impact if APS were to allocate demand credits based on the PCAFs, and energy credits based on the rates developed by Mr. Beach?

A. Because each recommended credit is larger than the credit used by APS in calculating its net cost of service for NEM customers, the result of using the recommended credits would be to reduce the net cost of service relative to APS's estimates.

Q. Why is that?

A. APS only credits approximately 19% of the costs of generation demand to NEM customers. Mr. Beach's PCAFs credit NEM customers with between 36.2% and 53.2%, depending on the orientation of the PV system.[57] In addition, APS gives absolutely no credit to NEM customers for avoiding distribution or transmission demand costs. Regarding energy credits, APS uses a conservative value for avoided fuel costs, whereas Mr. Beach's energy credit rate more accurately reflects the actual avoided costs that APS would see.

Q. Is the application of larger credits the only factor that affects APS's stated contributions towards cost of service for NEM customers?

A. No. There is one further change that needs to be implemented to determine the net cost of service for NEM customers. Mr. Snook states in his testimony that the NEM customers on energy-based rates cover only approximately 36% of the cost to serve them while NEM customers on demand rates cover around 72% of the cost to serve them.[58] However, Mr. Snook also notes that past decisions in APS rate cases have established that the residential rate class covers a lower percentage of the cost of service as a whole (approximately 87%), and the difference is made up for by other customer classes.[59] Mr. Snook's calculations of NEM customers covering only 36% and 72% of the cost to serve them, for energy-rates and demand-rates respectively, are based on a retail ROR of 8.07% being applied across the board to all classes, thus implying the residential class has to cover the full cost to serve them, as opposed to a lower ROR as directed by the

[57] Beach Testimony, Exhibit 2, p. 12.
[58] Snook Testimony, p. 20.
[59] Snook Testimony, p. 20.

Commission. APS ignores its own target of a 4.99% ROR from these customers.[60] In effect, APS is ignoring the Commission's established policy regarding cost responsibility for the various classes in presenting its comparison of the percentage of costs of service recovered through rates. This is misleading at best.

Q. What adjustments would you recommend to the cost of service calculation, to implement the changes mentioned above?

A. I would recommend a two-pronged approach to estimating the true net cost of service for the hypothetical residential solar customer class:

1. In place of using an 8.07% ROR as Mr. Snook has done, an ROR of 4.99% should be used for developing the revenue requirement for NEM customers. This revenue requirement with a lower ROR should then be used for determining what percentage of the cost to serve NEM customers are already meeting. The return target of 4.99% is consistent with APS's method for calculating demand and energy credits for NEM customers.[61]
2. TASC's revised demand and energy credits should be used to determine the net cost to serve NEM customers.

Q. What would be the combined impact of these two changes?

A. The combined impact of these two changes would be to reduce the net cost to serve NEM customers.

Q. Have you estimated the appropriate credits that are associated with the solar generation by NEM customers?

A. Yes. I have calculated the estimated credits based on the credits discussed above. **Table 4** below presents a comparison between APS's energy credits, and TASC's revised energy credits.

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[60] APS Response to Vote Solar Data Request 2.1, Attachment APS15767, p. 2 of 48 (See Exhibit WAM-3).

[61] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 2 of 37 – 4 of 37 (See Exhibit WAM-3).

Table 4: Comparison between APS and TASC Energy Credits Allocated to Residential Solar Customers

	Generation (MWh)	Credit Rate ($/MWh)	Credit ($)
APS Solar Energy Credit	291,498	28.95	$8,438,867
TASC Solar Energy Credit	291,498	42.15	$12,286,641
Difference	0	13.2	$3,847,774

Table 5 below presents a comparison between APS's allocated demand credits, and TASC's recommended demand credits, using the credit percentages noted in **Table 3** for south oriented solar systems. The credits presented here are for solar customers on energy rates and demand rates combined, based on APS's targeted ROR of 4.99%.

Table 5: Comparison between APS and TASC Demand Credits Allocated to Residential Solar Customers

	Generation Demand	Transmission Demand	Distribution Demand (Substation/ Primary Distribution)	Distribution Demand (Secondary/ Transformer)	Total
APS' Solar Demand Credit	$2,356,788	$0	$0	$0	$2,356,788
TASC Demand Credit (South-Facing)[62]	$4,630,343	$1,034,833	$2,019,171	$688,104	$8,372,451
Difference	$2,273,555	$1,034,833	$2,019,171	$688,104	$6,015,664

Q. Have you estimated the impact of using the revised credits, and a 4.99% ROR on the net cost to serve NEM customers relative to collected revenue?

A. Yes. I have estimated the impacts on the portion of their cost to serve that the NEM customers on energy rates pay in a couple of different ways.

Assuming a retail ROR of 8.07% as APS has done (which, as mentioned above, is misrepresentative of the real world situation), but using TASC's recommended credits, NEM customers on energy rates pay 46% of their cost of service, as opposed to 36% as

[62] These demand credits have been calculated assuming all customer solar systems have a south-facing orientation. This understates the actual total demand credits that would accrue to solar customers as a whole, because some solar systems would be west facing, and would have a greater impact on peak demand, thus having a higher credit percentage applicable to them. The total demand credits in such a situation would be higher than the value presented here, but lower than if ALL solar systems were west facing.

APS has stated.[63] However, if I correct APS's revenue requirement to reflect its targeted 4.99% ROR[64] and then continue to use APS's credits, NEM customers on energy rates pay 42% of the cost to serve them. Using the same 4.99% ROR assumption and using TASC's recommended credits results in an increases to 58%.

Q. Please comment on your results.

A. Using more appropriate credits for NEM generation reduces the net cost to serve NEM customers, meaning that the shortfall between the estimated net cost of service and revenue collected from NEM customers under current rates is less than presented by APS witness Snook. The results presented above are conservative in that I assumed that all NEM systems were oriented facing due south when developing my demand credits, which results in a lower demand credits than if some NEM systems were oriented toward the west. This is consistent with the statements of TASC witness Mr. Beach, which pointed out that encouraging and incentivizing west-facing systems could improve the value of solar delivered by NEM systems.[65]

Finally, it should be noted that these estimates of net cost of service for NEM customers do not account for any of the other important direct benefits identified in TASC witness Mr. Beach's testimony, such as fuel hedging or market price mitigation, or any societal benefits.

Q. Does this complete your rebuttal testimony?

A. Yes.

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[63] Snook Testimony, p.3

[64] APS Response to Vote Solar Data Request 2.3, Attachment p. 2 of 37 – 4 of 37 (See Exhibit WAM-3).

[65] Beach Testimony, p. 24.

EXHIBIT WAM-1

RESUME FOR WILLIAM A. MONSEN

Table of Exhibits

Exhibit WAM-1: Resume of William A. Monsen

Exhibit WAM-2: APS Responses to TASC Data Requests

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

Exhibit WAM-4: Excerpt from "Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015

Exhibit WAM-5: Excerpt from "Energy Star: Program Requirements for Programmable Thermostats,"

Exhibit WAM-6: Excerpt from Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Exhibit WAM-7: California Energy Markets, Issue No. 1379, April 1, 2016

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures

Exhibit WAM-9: Excerpt from PG&E 2014 General Rate Case Phase II Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design, Application 13-04-012

Exhibit WAM-10: Excerpt from California Public Utilities Commission, Decision15-08-005

Exhibit WAM-11: Excerpt from California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

Exhibit WAM-1: Resume of William A. Monsen

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.

William A. Monsen

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (California PUC) Applications 90-08-066, 90-08-067, 90-09-001
   Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.

2. California PUC Application 90-10-003
   Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.

3. California Energy Commission Docket No. 93-ER-94
   Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.

4. California PUC Rulemaking 94-04-031 and Investigation 94-04-032
   Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.

5. Massachusetts Department of Telecommunications and Energy DTE 97-120
   Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.

6. California PUC Application 97-12-039
   Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.

7. California PUC Application 99-09-053
   Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.

8. California PUC Application 99-09-053
   Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.

9. California PUC Rulemaking 99-10-025
   Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. California PUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.

11. California PUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.

12. California PUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.

13. California PUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.

14. California PUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. California PUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.

16. California PUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.

17. Arizona Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.

18. California PUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.

19. California PUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.

20. California PUC Rulemaking 01-10-024
Direct testimony of William A. Monsen Regarding Long-Term Resource Planning Issues On Behalf of the City of San Diego. June 23, 2003.

21. California PUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.

22. California PUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation On Behalf of the Local Government Commission Coalition. April 15, 2004.

23. California PUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.

24. California PUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.

25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. October 18, 2004.

28. California PUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.

29. California PUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. California PUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.

31. California PUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.

32. California PUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.

33. California PUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.

34. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.

35. California PUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.

36. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.

37. Colorado PUC Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.

38. California PUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.

39. California PUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association Regarding Integrated Resource Planning. September 13, 2006.

41. California PUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company For Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.

42. Colorado PUC Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy Association. April 28, 2008.

43. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.

44. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.

45. California PUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of The California Demand Response Coalition Concerning Demand Response Cost-Effectiveness And Baseline Issues. November 24, 2008.

46. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation And Rate Design Issues In The San Diego Gas & Electric Company And Southern California Gas Company Biennial Cost Allocation Proceeding. December 23, 2008.

47. California PUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost Allocation And Rate Design. January 9, 2009.

48. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. January 27, 2009.

49. California PUC Application 08-11-014
Testimony of William A. Monsen on Behalf of The City of San Diego Concerning the Application of San Diego Gas & Electric Company tor Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.

51. Public Utilities Commission of the State of Colorado 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.

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Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.

53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," September 15, 2010.

54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," November 2, 2010.

55. California PUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.

56. Public Service Company of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.

57. California PUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. July 16, 2012.

59. California PUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding. July 23, 2012.

60. California PUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. July 23, 2012.

61. California PUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.

62. California PUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. August 3, 2012.

63. California PUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates' Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. September 14, 2012.

65. Public Utilities Commission of the State of Colorado Docket No 11A-869E Supplemental Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. October 5, 2012.

66. Public Utilities Commission of the State Oregon Docket No UM 1182 Northwest and Intermountain Power Producers Coalition Direct Testimony of William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness Reply Testimony of William A. Monsen. January 14, 2013.

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Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. September 30, 2013.

69. California PUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. October 14, 2013.

70. California PUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy Alliance Regarding the Proposed Merger of NV Energy, Inc. with Midamerican Energy Holdings Company. October 24, 2013.

71. California PUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission and Storage Rate Application. August 11, 2014.

72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August 25, 2014.

73. California PUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission & Storage Application. September 15, 2014.

74. California PUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning Residential Electric Rate Design Reform. September 15, 2014.

75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Phase1A of the 2014 Long-Term Procurement Planning Proceeding. September 24, 2014.

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.

79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.

80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.

81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.

82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen On Behalf of The Alliance for Solar Choice (TASC). October 27, 2015.

Exhibit WAM-2: APS Responses to TASC Data Requests

This Exhibit includes the following Data Responses: TASC DR 1.15, 4.1, and 4.4 (Note: Response to DR 1.15 includes feeder data that has not been included here. It can be provided on request.

TASC'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 26, 2016

TASC 1.15: Please provide, in Excel format, hourly load data, for the most recent historical year for which data is available, for a representative sample of distribution feeders on the APS system.

Response: APS is gathering this information and will provide a response as soon as possible.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.1: Please provide hourly loads for all of APS's residential customers for 2014 and 2015 in Excel format. In addition, please provide hourly loads for the following subsets of residential customers:

a. Customers participating in APS's energy efficiency programs;

b. Customers participating in APS's demand response programs;

c. Customers located in the city limits of Phoenix;

d. Customers located in the Phoenix metropolitan area;

e. Customers with rooftop solar;

f. Customers that do not have central air conditioning;

g. Customers that have swimming pools;

h. Customers that have setback thermostats that control their air conditioners;

i. Customers that are dual fuel customers (as discussed on page 26 of Mr. Snook's testimony);

j. Customers living in apartments (as discussed on page 25 of Mr. Snook's testimony);

k. Customers that are "empty nesters" (as discussed on page 25-26 of Mr. Snook's testimony).

For each set of hourly loads, please indicate the average number of customers included in each set.

Response: Hourly loads for each of APS's 1.1 million residential customers would consist of over 9.5 million data points annually, and is too voluminous to provide. However, APS is providing as APS15876 the total hourly load for 2014 for customers on each residential rate APS offers. These loads are disaggregated by each load type used by APS in the 2014 Cost of Service Study as discussed in APS Witness Snook's direct testimony. APS15876 also provides customer counts for each of the load types. Additionally, please see APS15871, provided in the Company's response to TASC Question 3.2, for average hourly loads for dual fuel, winter visitor, and apartment customers for 2014 as discussed in Mr. Snook's testimony. If average per customer loads are desired, please divide the total hourly loads by the customer count provided.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.1 Supplemental Response:

a - b. APS does not possess hourly load data for energy efficiency and demand response participants as the Company's customer information system (CIS) does not track these customers.

c – d. APS objects to this request as unduly burdensome and seeking irrelevant information that is not likely to lead to the discovery of admissible evidence. Further, no documents exist with this information. Although APS's customer information system does contain the zip codes in which customers live, any document showing this information would have to be created through targeted queries to its database, compilation of data, and organization and labeling of data into an understandable Excel format.

e. Please see APS15876 for total hourly loads and customer counts of customers with rooftop solar, from which an average hourly load can be easily derived.

f – h. APS does not possess hourly load data for central air conditioning, swimming pools, or setback thermostat customers as the Company's CIS does not track these customers.

i – j. Please see APS15878, provided in the Company's second supplemental response to TASC Question 3.2, for average hourly loads for dual fuel customers and apartment dwellers.

k. APS does not possess hourly load data for "empty nesters", as CIS does not track these customers.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.4: Is APS aware of any instances in which power flows from residential NEM systems interconnected at the secondary distribution voltage level have resulted in power being backfed onto APS's transmission system? If your response is anything except for an unqualified "no," please provide data indicating precisely when such backfeeding occurred and the costs incurred by APS as a result of that backfeeding.

Response: APS is not currently aware of any power backfed into APS's transmission system solely from residential NEM systems; however, APS is aware of several distribution feeders that have experienced reverse flow directly due to residential NEM systems.

Attached as APS15879 is a table showing APS's top 25 distribution feeders by interconnected residential NEM systems and the number of NEM systems connected to each. The eleven feeders that experienced reverse power flow in 2015 are designated in yellow.

To date, APS has not incurred equipment or system costs directly attributable to these reverse power flows. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of reverse power flows will only increase.

Reverse Power Flows in 2015 – Highest System Count NEM Distribution Feeders				
Feeder	NEM System Count	Lowest 15 Min	Lowest 15 Min 2015 (MWs)	Total Hours of Reverse Flow
1	848	5/8 @ 12:45	-0.9368	328.75
2	702	1/16 @ 13:15	0.0005	
3	689	5/9 @ 12:45	-2.0783	935.50
4	467	4/16 @ 13:00	-0.6794	133.25
5	451	5/8 @ 12:45	-0.5829	49.75
6	409	5/8 @ 12:45	-0.4658	184.50
7	402	3/15 @ 12:30	1.1599	
8	353	4/16 @ 10:30	0.0203	
9	338	8/7 @ 19:45	-0.0008	18.00
10	331	9/29 @ 10:15	-0.0011	2.25
11	324	10/8 @ 13:15	1.2314	
12	322	5/8 @ 13:30	-0.1282	15.75
13	284	11/17 @ 13:00	0.8633	
14	274	11/6 @ 13:30	0.8384	
15	268	4/16 @ 12:30	0.4930	
16	260	4/16 @ 12:30	0.6152	
17	258	11/5 @ 12:15	0.7298	
18	253	5/8 @ 13:45	-0.1101	29.00
19	229	4/27 @ 11:15	-0.0020	0.50
20	228	6/10 @ 9:15	0.0008	
21	224	4/16 @ 12:30	0.1960	
22	208	11/9 @ 10:15	1.0964	
23	202	9/2 @ 3:30	4.5452	
24	194	9/23 @ 3:00	2.2743	
25	189	3/9 @ 13:15	-0.0927	1.50

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

This Exhibit includes the following Data Responses: Vote Solar DR 1.1, 2.1, 2.3, and 2.4

2014 Allocation Factor Input Page

Line No.	Customer Class	# of Customers	Energy Consumption (MWh)	Delivery Level %	CP (MW)	NCP (MW)	12CP (MW)	36CP (MW)	Inst. Size (MW)	Delivery Level %	Line No.
	Residential										
0	Residential - Solar Site (Energy Rates)	37 675	388 700		123 485	112 803	71 599	122 516	108 840		0
0	Residential - Solar Site (Demand Rates)	1 176	23 453		7 530	6 084	4 086	7 503	11 030		0
1	R-12 (No Solar)	488 377	3 870 040		847 208	865 067	647 720	1 138 337	2 127 417		1
2	RT-1 (No Solar)	149 665	3 808 026		705 798	697 056	438 662	902 882	1 119 152		2
3	RCT-1 (No Solar)	37 488	728 449		180 141	176 778	127 434	242 342	303 340		3
4	RT-2 (no Solar) or RT-6P	388 739	4 630 634		1 170 898	1 080 180	781 280	1 341 702	2 163 108		4
5	RCT-2 (no Solar)	91 251	2 002 497		551 562	5 15 475	234 491	501 438	807 202		5
6	Total Residential	1 154 180	15 451 594		3 196 180	3 300 531	2 347 317	4 242 196	6 540 547		6
	General Service										
7	G-20	439	39 042		11 200	8 930	6 917	32 443	28 138		7
8	G-32 E-32 G-32LV	105 708	1 453 588		276 400	263 300	238 083	341 735	545 276		8
9	G-32 TV-100kW	14 484	2 878 376		636 400	608 735	388 317	636 708	847 773		9
10	Total G-32 G-32 G-100kW	120 274	4 333 372		912 800	872 035	626 375	978 522	1 393 049		10
11	Total G-32 G-32 G-100kW @ Dist. Primary	53		0 981768					3 564	0 981484	11
12	Total G-32 G-32 G-100kW @ Secondary T-d	120 221		0 988200					1 386 686	0 988016	12
13	Total G-32 G1-400kW	4 252	3 193 872		538 872	538 872	442 242	538 864	814 177		13
14	Total G-32 G1-400kW @ Dist. Primary	35		0 979200					12 072	0 979484	14
15	Total G-32 G1-400kW @ Secondary T-d	4 217		0 988200					801 604	0 984186	15
16	Total G-32 G1-600kW	634	1 688 182		384 800	339 800	338 087	388 842	383 833		16
17	Total G-32 1 000kW	121	1 488 116		186 200	168 780	133 868	188 888	394 302		17
18	Total G-32 G1-Hvy	755	3 857 276	-	645 800	508 580	579 275	454 658	667 693		18
19	Total G-32 G1-Hvy @ Transmission Level	3		0 999000					3 746	0 999253	19
20	Total G-32 G1-Hvy @ Dist. Primary	57		0 983800					103 387	0 987917	20
21	Total G-32 G1-Hvy @ Secondary T-d	715		0 987200					653 387	0 989120	21
22	Total G-32 G-32	126 221	13 031 482		1 673 600	1 579 635	1 424 487	2 102 104	2 808 539		22
23	G-32 TOU 0-20kW	204	3 516		530	500	540	537	1 384		23
24	G-32 TOU 21-100kW	132	34 742		6 000	4 800	4 125	5 700	6 100		24
25	Total G-32 TOU 0-100kW	336	38 258		5 530	5 300	4 715	6 025	8 484		25
26	Total G-32 TOU 0-100kW @ Dist. Primary	1		0 983200					32	0 986872	26
27	Total G-32 TOU 0-100kW @ Secondary T-d	335		0 990200					8 434	0 994729	27
28	G-32 TOU 101-400kW	73	76 184		16 800	16 230	8 880	11 600	16 775		28
	Total G-32 TOU 101-400kW @ Dist. Primary			0 994200					2 729	0 997000	
	Total G-32 TOU 101-400kW @ Secondary T-d			0 995200					13 041	0 998000	
29	G-32 TOU 401-600kW	45	132 848		15 000	14 230	14 880	15 800	24 074		29
30	G-32 TOU 1000+kW	14	131 782		15 200	14 529	15 467	23 000	30 300		30
31	Total G-32 TOU 401+kW	61	264 798		30 200	28 759	30 348	43 700	54 374		31
32	Total G-32 TOU 401+kW @ Dist. Primary	14		0 993200					8 172	0 993017	32
33	Total G-32 TOU 401+kW @ Secondary T-d	47		0 997800					43 794	0 998000	33
34	Total G-32 TOU	408	375 041		56 000	47 575	44 175	60 054	80 139		34
35	General Service School TOU	116	110 000		19 200	16 130	14 000	35 000	43 172		35
36	Total G-34	30	201 000		40 500	37 475	117 100	42 840	121 933		36
37	Total G-34 @ Transmission Level	3		0 100000					31 425	0 120870	37
38	Total G-34 @ Dist. Substation	-		0 000000					-	0 000000	38
39	Total G-34 @ Dist. Primary	13		0 012700					121 388	0 000153	39
40	Total G-34 @ Secondary T-d	9		0 204000					43 488	0 203877	40
41	Total G-35	37	2 177 [illegible]		228 000	219 400	245 000	286 781	286 110		41
42	Total G-35 @ Transmission Level	3		0 100000					31 425	0 000000	42
43	Total G-35 @ Dist. Substation	-		0 000000					-	0 000000	43
44	Total G-35 @ Dist. Primary	13		0 425000					121 388	0 974436	44
45	Total G-35 @ Secondary T-d	21		0 472000					241 588	0 998043	45
46	Total General Service	127 [illegible]	15 [illegible]		3 245 000	3 100 351	1 880 217	3 [illegible]	1 [illegible]		46
47	E-20+	1 457	346 679		42 000	40 175	34 475	73 305	123 484		47
48	STREETLIGHTS	14 [illegible]	142 [illegible]		-	-	5 230	30 000	33 060		48
49	DARK TO DAWN	6 316	37 [illegible]		-	-	1 325	6 200	6 200		49
50	Total ROR	1 [illegible]	27 [illegible]		9 [illegible]	6 [illegible]	1 [illegible]	6 [illegible]	10 [illegible]		50

2014 Allocation Factor Input Page

	ENERGY Line Loss Values		DEMAND Line Loss Values				
	1.01832	(3) to (4)	1.01300	(2) to (4)			
	1.00302	(4) to (5)	1.01300	(2) to (5)			
	1.04629	(5) to (6)	1.03000	(6) to (6)			
	1.00200	(6) to (7)	1.00300	(6) to (7)			
	1.00200	(7) to (8)	1.01237	(7) to (8)			
	1.02000	(8) to (9)	1.01238	(8) to (9)			
	1.04637		1.04637				
Residential Credit Customers							
SHP MINERAL	1	43012	8 880	4.276	8 947	15.300	15.300
MEXICO TAP BOSS	1	38 014	4 600	4 326	3 917	4.700	4 700
MEXICO TAP BENDA	1	1 629	139	149	117	700	700
MEXICO TAP MEDOSA	1	1 364	200	200	233	600	600
MEXICO TAP PALACION	1	4 684	600	600	697	1 300	1 300
SOLANA PLANT	1	34 340	-	-	2 828	20 100	20 100
BLAS ARLINGTON	1	10 324	-	-	148	17 300	17 300
MARQUERALA PLANT	1	10 345	-	-	1 040	11 300	11 300
MESQUITE PLANT	1	2 484	-	-	118	6 600	6 600
PANDA PLANT	1	34 893	-	-	578	16 100	16 100
Total Residential Credit Customers	43	177 732	15 020	10 000	16 584	98 400	98 400
	1 143 057	37 384 621	6 047 700	5 088 882	4 317 723	7,077,676	10 634,203
Residential - E-12 Solar Delivered	13 326	72 757	28 734	22 479	18 974	32 428	54 700
Residential - ET-1 Solar Delivered	6 149	61 184	21 888	18 943	12 830	23 800	38 600
Residential - ET-2 Solar Delivered	11 054	133 231	48 314	43 248	27 335	38 417	81 300
Residential - Solar Delivered (Energy Rates)	37 570	267 212	98 954	81 139	58 139	104 757	174 600
Residential - E-12 Solar Net	13 326	10 701	28 685	18 959	18 340	32 428	54 700
Residential - ET-1 Solar Net	6 149	39 837	21 270	17 484	11 808	23 800	38 600
Residential - ET-2 Solar Net	11 054	70 842	44 613	37 017	25 335	38 417	81 300
Residential - Solar Net (Energy Rates)	37 570	111 238	92 569	73 371	55 483	114 737	174 600
Residential - E-CT-1 Solar Delivered	355	5 917	2 280	1 801	1 284	2 675	3 651
Residential - ET-2 Solar Delivered	821	12 773	3 975	3 695	2 407	4 700	7 673
Residential - Solar Delivered (Demand Rates)	1 176	18 690	6 177	5 488	3 691	7 374	11 044
Residential - E-CT-1 Solar Net	355	4 827	2 285	1 498	1 248	2 675	3 651
Residential - ET-2 Solar Net	821	8 715	3 914	3 234	3 215	4 700	7 673
Residential - Solar Net (Demand Rates)	1 176	13 538	6 200	5 140	3 439	7 375	11 014
Residential - E-12 Solar Received	-	43 209	7 101	3 628	2 734	-	-
Residential - ET-1 Solar Received	-	21 32*	833	1 311	882	-	-
Residential - ET-2 Solar Received	-	27 589	1 781	2 629	2 087	-	-
Residential - Solar Received (Energy Rates)	-	108 918	9 715	7 568	5 703	-	-
Residential - E-CT-1 Solar Received	-	3 099	24	55	48	-	-
Residential - ET-2 Solar Received	-	4 079	57	101	119	-	-
Residential - Solar Received (Demand Rates)	-	6 999	81	156	168	-	-
Residential - E-12 Solar Site	13 326	126 038	35 835	32 600	31 583	35 828	54 704
Residential - ET-1 Solar Site	6 149	82 539	37 748	34 377	16 456	37 748	43 917
Residential - ET-2 Solar Site	11 054	161 391	53 848	54 499	30 429	38 729	81 139
Residential - Solar Site (Energy Rates)	37 570	369 768	127 428	112 053	78 468	112 016	180 040
Residential - E-12 Solar Delivered	13 326	72 757	28 734	22 479	18 974	32 428	54 700
Residential - ET-1 Solar Delivered	6 149	61 184	21 888	18 943	12 830	23 800	38 600
Residential - ET-2 Solar Delivered	11 054	133 231	48 314	43 248	27 335	38 417	81 300
Residential - Solar Delivered (Energy Rates)	37 570	267 212	98 954	81 139	58 139	104 737	174 600
Residential - E-CT-1 Solar Site	355	5 940	3 081	3 176	1 673	2 675	4 545
Residential - ET-2 Solar Site	821	16 792	4 895	4 579	3 172	4 673	7 647
Residential - Solar Site (Demand Rates)	1 176	22 432	7 976	7 754	4 845	7 348	11 893
Residential - E-CT-1 Solar Delivered	355	5 917	2 280	1 801	1 284	2 675	3 651
Residential - ET-2 Solar Delivered	821	12 773	3 975	3 695	2 407	4 700	7 673
Residential - Solar Delivered (Demand Rates)	1 176	18 690	6 177	5 488	3 691	7 374	11 044
Residential - E-12 Solar (Customer Usage)		32 831	6 180	10 530	5 708	3 807	3 204
Residential - ET-1 Solar (Customer Usage)		21 888	6 340	6 663	3 676	1 930	3 746
Residential - ET-2 Solar (Customer Usage)		48 825	12 956	14 457	8 234	2 722	7 673
Residential - Solar (Customer Usage)(Energy Rates)		102 557	25 541	31 414	17 618	8 679	15 764
Residential - E-CT-1 Solar (Customer Usage)		1 732	320	438	239	63	310
Residential - ET-2 Solar (Customer Usage)		4 009	867	1 113	625	111	364
Residential - Solar (Customer Usage)(Demand Rates)		5 710	1 186	1 550	864	174	770
Residential - E-12 Solar Generation		53 357	11 272	14 210	8 449	3 807	3 204
Residential - ET-1 Solar Generation		53 357	6 675	7 793	4 603	1 930	3 746
Residential - ET-2 Solar Generation		133 088	13 033	18 879	12 291	2 722	7 673
Residential - Solar Generation (Energy Rates)		239 472	31 780	38 782	25 343	8 679	15 764
Residential - E-CT-1 Solar Generation		3 652	616	510	388	63	310
Residential - ET-2 Solar Generation		8 317	1 304	1 304	785	117	364
Residential - Solar Generation (Demand Rates)		11 969	1 920	1 790	1 182	180	770

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.1: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company provided a chart depicting the "Cost of Service Results for A Typical Solar Customer." Please provide all workpapers supporting this chart, including linked references to the Cost of Service Working Model provided by APS in response to VS 1.1.

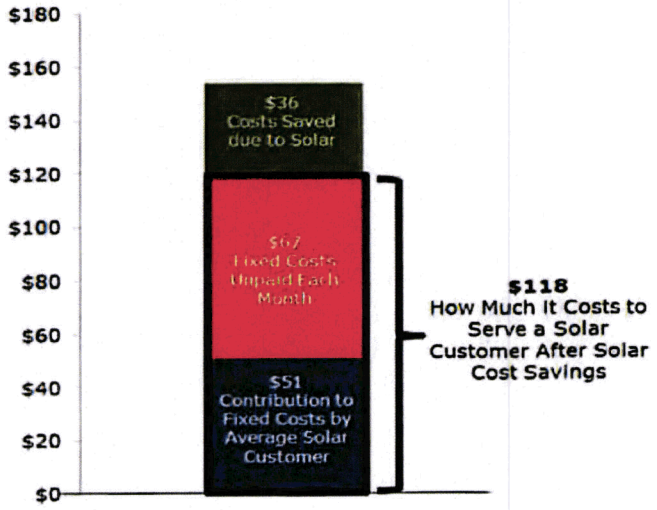
Response: See attached as APS15767 for the workpapers supporting this chart.

Back-Up for Chart:

	(A)		(B)	(C)	(D)
	Total Monthly Cost to Serve Typical Solar Customer		What Solar Customers Should Pay	What Solar Customers are Actually Paying	Unrecovered Amount (Column B-C)
Base Cost to Serve a Customer	$136		$104	$44	$61
Adjustors	$18		$14	$8	$6
Total	$154		$118	$51	$67

Costs Saved due to Solar	$36

Cost of Service Results for A Typical Solar Customer



Residential Solar @ Actual ROR (Energy Rates - 8/TE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission &	Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base														
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,602	$0		$6,218,572	$20,756,268	$20,411,249	$0	$4,840,752	$0	$0	$6,019,457	$114,452,695
2)	Customer Accounts								$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense								$563,497					$563,497
4)	Customer Deposits					(42,601)	(164,230)	(143,235)						(370,065)
5)	Customer Advances	(15,524)				(11,125)	(38,870)	(32,347)						(98,866)
6)	Total Rate Base	$51,435,845	$1,356,602	$0		$6,162,420	$20,553,172	$20,427,672	$2,374,732	$4,840,752	$107,877	$121,842	$6,019,457	$116,570,818
7)	Actual Earned ROR @ 4.34%													
8)	Return on Rate Base (Line 6 * Line 7)	[illegible]	[illegible]	$0		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]
Computation of Income Taxes														
9)	Weighted Cost of Long Term Debt @ 2.40%													
10)	Tax Rate @ 39.19%													
11)	Income Taxes (Line 7*Line 9)/(Line 10)*(1-Line 10)-Line 9)	[illegible]	[illegible]	$0		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Expenses														
12)	Expenses	$8,029,890	$5,637,930	$3,661,494		$567,284	$2,791,108	$2,036,147	$0	$1,337,751	$0	$0	$1,208,727	$23,172,905
13)	Customer Accounts	$0	$0	$0		$0	$0	$0	$1,520,621	$0	$304,842	$115,894	$0	$1,964,157
14)	Cust. Service & Info and Sales Expense	$0	$0	$0		$0	$0	$0	$700,635	$0	$0	$0	$0	$700,635
15)	Total Expenses	$8,029,890	$5,637,930	$3,661,494		$567,284	$2,791,108	$2,036,147	$2,221,257	$1,337,751	$304,842	$115,894	$1,208,727	$27,005,704
Revenue Requirement														
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,457,294	$5,456,171	$3,661,494	[illegible]	$567,500	[illegible]	[illegible]	$1,890,679	$633,061	$255,256	$103,191	$863,832	$19,707,483
17)	Less: Revenue Credits	$1,586,373	$2,732,994	$847,066	$35,400	$201,831	$125,584	$4,763	$4,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @ 4.34%**	**$11,870,919**	**$2,702,177**	**$2,714,428**	**($104,247)**	**($146,429)**	**($11,202)**	**$1,876,047**	**$611,000**	**$233,246**	**$103,191**	**$863,832**	**$14,133,463**	
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs ($/kWh)**	**0.0444**	**0.0101**	**0.0102**	**-0.0004**	**-0.0006**	**-0.0000**	**0.0070**	**0.0023**	**0.0011**	**0.0004**	**0.0032**	**0.0530**	
21)	**Number of Customers**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**
22)	**Functional Unit Costs ($/Customer/month)**	**$0.29**	**$20.01**	**$0.20**	**-$0.32**	**-$0.45**	**-$0.07**	**$5.56**	**$2.00**	**$0.86**	**$0.32**	**$2.70**	**$43.80**	

Residential Solar @ Targeted ROR (Energy Rates - 8/TE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission &	Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base														
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,602		$0	$6,218,572	$20,756,268	$20,411,249		$4,840,752			$6,019,457	$114,452,695
2)	Customer Accounts								$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense								$563,497					$563,497
4)	Customer Deposits					(42,601)	(164,230)	(143,235)						(370,065)
5)	Customer Advances	(15,524)				(11,125)	(38,870)	(32,347)						(98,866)
6)	Total Rate Base	$51,435,845	$1,356,602	$0		$6,162,420	$20,553,172	$20,427,672	$2,374,732	$4,840,752	$107,877	$121,842	$6,019,457	$116,570,818
7)	Targeted ROR @ 4.95%													
8)	Return on Rate Base (Line 6 * Line 7)	$2,546,629	$67,154	$0		$304,511	$1,016,848	$1,010,236	$117,495	$239,594	$5,340	$6,030	$(10,531)	$5,770,335
Computation of Income Taxes														
9)	Weighted Cost of Long Term Debt @ 2.40%													
10)	Tax Rate @ 39.19%													
11)	Income Taxes (Line 7*Line 9)/(Line 10)*(1-Line 10)-Line 9)	$628,727	$22,841	$0		$49,202	$472,152	$325,175	$38,262	$77,864	$1,736	$1,961	$46,841	$1,610,939
Expenses														
12)	Expenses	$8,029,890	$5,637,930	$3,661,494		$567,284	$2,791,108	$2,036,147		$1,337,751			$1,208,727	$23,172,905
13)	Customer Accounts								$1,520,621		$304,842	$115,894		$1,964,157
14)	Cust. Service & Info and Sales Expense								$700,635					$700,635
15)	Total Expenses	$8,029,890	$5,637,930	$3,661,494		$567,284	$2,791,108	$2,036,147	$2,221,257	$1,337,751	$304,842	$115,894	$1,208,727	$27,005,704
Revenue Requirement														
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$11,425,211	$5,727,195	$3,661,494	$973,110	$4,524,614	$3,286,836	$2,351,917	$1,357,259	$1,317,759	$109,937	$123,853	$1,408,037	$30,407,942
17)	Less: Revenue Credits	$1,586,373	$2,732,994	$847,066	$35,400	$201,831	$125,584	$8,763	$22,010	$0	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @4.95%**	**$9,838,838**	**$2,994,201**	**$2,814,428**	**$937,710**	**$4,322,784**	**$3,161,254**	**$2,343,154**	**$1,335,249**	**$1,317,759**	**$109,937**	**$123,853**	**$1,408,037**	**$25,833,922**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs ($/kWh)**	**0.0368**	**0.0112**	**0.0105**	**0.0035**	**0.0162**	**0.0118**	**0.0123**	**0.0050**	**0.0049**	**0.0004**	**0.0005**	**0.0053**	**0.1000**
21)	**Number of Customers**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**	**27,075**
22)	**Functional Unit Costs ($/Customer/month)**	**$30.34**	**$21.81**	**$0.00**	**$2.58**	**$13.30**	**$10.04**	**$7.20**	**$4.08**	**$4.05**	**$0.34**	**$0.38**	**$4.33**	**$104.50**
23)	**Under Recovery (Targeted less Actual)($/Customer/month)**	**$20.34**	**$0.76**	**$0.00**	**$0.20**	**$10.70**	**$10.79**	**$1.24**	**$2.08**	**$0.00**	**$0.02**	**$1.32**	**$60.50**	

Residential Targeted ROR	[illegible]
Rate Base	[illegible]
Outstanding Income	[illegible]
Current Rate of Return	[illegible]

Residential Solar @ Actual ROR (Energy Rates - 8/TE)

Unbundled Functional Revenue Requirement before Energy Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$11,481,389	$1,356,802		$8,216,872	$28,798,298	$23,811,346	$0	$4,840,752			$3,014,487	$114,462,869
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,487					$580,487
4)	Customer Deposits				[illegible]	[illegible]	[illegible]						[illegible]
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base	$11,481,389	$1,356,802	$0	$8,102,466	$28,253,498	$23,427,649	$2,374,721	$4,840,752	$107,877	$121,842	$3,014,487	$116,550,910
7)	Actual Earned ROR @ -10.77%												
8)	Return on Rate Base (Line 6 * Line 7)	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 38.19%												
11)	Income Taxes (Line 7 Line Income Income (Line 1 Line 10)	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Expenses												
12)	Expenses	10,277,250	17,706,864	3,561,464	567,284	2,791,108	2,098,147		1,337,751			1,258,737	$39,466,609
13)	Customer Accounts							1,910,501		304,542	115,864		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,695					$700,695
15)	Total Expenses	$10,277,250	$17,706,864	$3,561,464	$567,284	$2,791,108	$2,098,147	$2,234,259	$1,337,751	$304,542	$115,864	$1,258,737	$42,140,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$342,121	$17,844,618	$3,561,464	[illegible]	[illegible]	[illegible]	$1,775,980	$401,725	$263,605	$62,369	$625,507	$18,727,421
17)	Less: Revenue Credits	$1,596,373	$2,733,984	$847,099	$30,400	$201,811	$129,984	$9,783	$22,010	$0	$0	$0	$6,574,021
18)	**REVENUE REQUIREMENT @-10.77%**	**($1,254,252)**	**$14,710,634**	**$2,714,428**	**($904,802)**	**($1,408,704)**	**($2,028,242)**	**$1,766,196**	**$380,715**	**$263,605**	**$62,369**	**$625,507**	**$14,153,390**
19)	**Energy Consumption (kWh)**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**
20)	**Functional Unit Costs (cents/kWh)**	**-0.0047**	**0.0001**	**0.0102**	**-0.0034**	**-0.0053**	**-0.0079**	**0.0066**	**0.0014**	**0.0011**	**0.0003**	**0.0023**	**0.0530**
21)	**Number of Customers**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**
22)	**Functional Unit Costs ($/Customer/month)**	**-$3.87**	**$45.27**	**$8.35**	**-$1.39**	**-$7.84**	**-$6.29**	**$5.48**	**$1.17**	**$0.87**	**$0.20**	**$1.93**	**$43.99**

Residential Solar @ Targeted ROR (Energy Rates - 8/TE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$11,481,389	$1,356,802		$8,216,872	$28,798,298	$23,811,346		$4,840,752			$3,014,487	$114,462,869
2)	Customer Accounts							1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,487					$580,487
4)	Customer Deposits				[illegible]	[illegible]	[illegible]						[illegible]
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base	$11,481,389	$1,356,802	$0	$8,102,466	$28,253,498	$23,427,649	$2,374,721	$4,840,752	$107,877	$121,842	$3,014,487	$116,550,910
7)	Targeted ROR @ 4.00%												
8)	Return on Rate Base (Line 6 * Line 7)	$459,639	$57,708	$0	$324,099	$1,130,140	$1,137,486	$115,489	$241,904	$5,393	$6,092	$150,671	$5,780,620
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 38.19%												
11)	Income Taxes (Line 7 Line Income Income (Line 1 Line 10)	$836,727	$21,981	$0	$88,824	$423,167	$326,135	$38,282	$77,994	$1,738	$1,963	$48,649	$1,859,938
	Expenses												
12)	Expenses	10,277,250	17,706,864	3,561,464	567,284	2,791,108	2,098,147		1,337,751			1,258,737	$39,466,609
13)	Customer Accounts							1,910,501		304,542	115,864		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,695					$700,695
15)	Total Expenses	$10,277,250	$17,706,864	$3,561,464	$567,284	$2,791,108	$2,098,147	$2,234,259	$1,337,751	$304,542	$115,864	$1,258,737	$42,140,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,572,636	$17,786,553	$3,561,464	$970,120	$4,324,414	$3,561,568	$2,387,017	$1,657,299	$311,753	$123,927	$1,408,057	$48,800,202
17)	Less: Revenue Credits	$1,596,373	$2,733,984	$847,099	$30,400	$201,811	$129,984	$9,783	$22,010	$0	$0	$0	$6,574,021
18)	**REVENUE REQUIREMENT @4.00%**	**$12,074,229**	**$15,052,488**	**$2,714,428**	**$934,720**	**$4,322,603**	**$3,391,582**	**$2,391,284**	**$1,635,289**	**$311,753**	**$123,927**	**$1,408,057**	**$46,226,181**
19)	**Energy Consumption (kWh)**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**	**397,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0452**	**0.0564**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0090**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1656**
21)	**Number of Customers**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**	**27,079**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.19**	**$46.36**	**$8.35**	**$2.88**	**$13.31**	**$10.44**	**$7.36**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$142.00**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$41.02**	**$1.07**	**$0.00**	**$4.87**	**$20.16**	**$16.26**	**$1.84**	**$3.86**	**$0.08**	**$0.19**	**$2.41**	**$42.66**

Note: The target ROR of 4.00% is the average residential non-solar ROR.

	Demand Credit	Energy Credit
Line 12 before credits	**$10,277,250**	**$17,706,864**
Line 12 after credits	**$8,030,004**	**$8,037,002**
Difference in the credits	**($2,247,246)**	**($9,669,862)**

	Weighted Average ROR
Incremental Targeted ROR	[illegible]
Rate Base	$ [illegible]
Operating Income	[illegible]
Current Rate of Return	[illegible]

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.3: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company stated that its cost of service study "incorporates and credits to solar customers the measurable costs that APS avoids when a customer installs rooftop solar."

a) Please list the categories of avoided costs that APS incorporated into its cost of service study.

b) Please describe the methodology APS used to calculate each category of avoided costs listed in response to subquestion (a).

c) For each category of avoided costs listed in response to subquestion (a), please describe where the Cost of Service Working Model provided in response to VS 1.1 calculates each avoided cost.

Response: a & b. In the cost of service study, the avoided costs for which APS credited solar customers are:

- A "Production Demand Credit" which provides the solar customers with a credit for their reduced demand on APS's system. This was calculated by taking the total megawatts APS delivers to the customer as a percent of the customer's total site load (see APS's response to VS 2.4.c 'Solar Site' for a description of this term) for both non-coincident and coincident peak during the 4 system peak months of the year (June-September). This is consistent with the "average and excess" method of allocating production demand cost required by the ACC. This then derived a blended average that credits the solar customers for offsetting a portion of APS's peak load. The total amount credited for solar energy customers was $2.2M (or a reduction of 18.66% in their production demand cost) and for solar demand customers it was $109k (or a reduction of 14.64% in their production demand cost). See APS15768.

- An "Energy Fuel Credit" which provides the solar customers with a credit for the energy they actually produce. This is calculated by first grossing up their total energy production to recognize the line loss benefit. Then APS applied the EPR-6 excess generation rate (see APS15773 for a copy of the EPR-6 tariff) to the grossed

up amount of energy produced to calculate the Energy Fuel Credit. This amount is then credited to the solar energy customers. The total amount credited for solar energy customers was $8M and for solar demand customers it was $370k. See APS15768.

- An explicit "Transmission Credit" was not developed in this study. However, transmission costs were allocated on a delivered energy basis. This is conservative and over-credits solar energy customers for avoided transmission. A more precise method would be to allocate cost at the 4 system coincident peak months and credit the difference based on the delivered data.

- A "Distribution Credit" was not applied since the non-coincident peak occurred at nearly the same time for both site and delivered data, thus indicating no significant avoided distribution costs.

No other avoided costs existed as a results of rooftop solar generation.

c. The credits are inputs into the working model, but attached as APS15768 are the workpapers that calculate each avoided cost mentioned above. The calculation is done as a separate analysis using load data and information from the cost of service and then the credits are applied in the O&M report in the cost of service, which reduces the overall cost to serve those customers.

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Energy Credit
Test Year Ending 12/31/2014

	Customer Class	MWhs @ Customer Level	MWhs @ Generation Level	EPR-6 Fuel Rate (cents/kWh)	2014 Solar Fuel Credit
1.	Residential - Solar Generation (Energy Rates)	258,473	278,731	2.895	$8,069,264
2.	Residential - Solar Generation (Demand Rates)	11,839	12,767	2.895	$369,612
3.	Total	270,312	291,498		$8,438,876

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Demand Credit
Test Year Ending 12/31/2014

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
1.	Residential - Solar Generation (Energy Rates)				
	June	76.5	104.1	93.4	104.8
	July	94.9	122.5	111.3	122.5
	August	93.2	119.8	94.2	105.1
	September	60.0	103.8	99.2	107.1
	Average	81.2	112.6	99.5	109.9
	Relationship - Delivery versus Site		27.90%		9.42%
	Peak 2 Point Average				**18.66%**

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
2.	Residential - Solar Generation (Demand Rates)				
	June	5.1	6.5	6.1	6.6
	July	6.2	7.5	7.1	7.5
	August	6.2	7.5	6.0	6.5
	September	4.0	6.3	6.2	6.6
	Average	5.4	7.0	6.4	6.8
	Relationship - Delivery versus Site		22.66%		6.62%
	Peak 2 Point Average				**14.64%**

Calculation of Demand Credit - Residential - Solar Generation (Energy Rates)

	Revenue Requirement @ -6.54% (Before Demand Credit)	Targeted Revenue Requirement @ Avg Residential ROR 4.99%
Total Rate Base	$51,435,445	$51,435,445
Return on Rate Base	($3,363,878)	$2,566,629
Taxes	($3,023,197)	$798,893
Expense	$10,277,250	$10,277,250
Revenue Credits	($1,598,373)	($1,598,373)
Revenue Requirement @ -6.54% (before Demand Credit)	$2,291,802	$12,044,399
% Difference in Delivery vs. Site		**18.66%**
Solar Demand Credit		**$2,247,395**

Residential - Solar Generation (Demand Rates)

	Revenue Requirement @ .79% (Before Demand Credit)	Targeted Revenue Requirement @ Avg Residential ROR 4.99%
Total Rate Base	$3,289,477	$3,289,477
Return on Rate Base	$25,987	$164,145
Taxes	($37,948)	$51,092
Expense	$651,121	$651,121
Revenue Credits	($119,754)	($119,754)
Revenue Requirement @ -6.54% (before Demand Credit)	$519,406	$746,604
% Difference in Delivery vs. Site		**14.64%**
Solar Demand Credit		**$109,301**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Energy Rates - SITE)

		Unbundled Functional Revenue Requirement											
		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,389	$1,356,802		$6,216,972	$26,756,256	$20,811,249		$4,840,752			$3,019,457	$114,452,869
2)	Customer Accounts							$0					$2,023,953
3)	Cust. Service & Info and Sales Expense							$1,794,234		$107,677	$121,842		
4)	Customer Deposits							$560,497					$560,497
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base				[illegible]	[illegible]	[illegible]						[illegible]
		$51,435,445	$1,356,802	$0	$6,102,496	$26,263,496	$20,427,943	$2,374,731	$4,840,752	$107,677	$121,842	$3,019,457	$116,050,610
7)	Actual Earned ROR @ -5.94%												
8)	Return on Rate Base (Line 6 * Line 7)	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.15%												
11)	Income Taxes (Line 7 Line 9) Line 6) Line 10) Line 15)	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Expenses												
12)	Expenses	$10,277,250	$9,637,530	$3,561,494	$567,284	$2,791,108	$2,036,147		$1,337,751			$1,208,737	$31,419,401
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,535					$700,535
15)	Total Expenses	$10,277,250	$9,637,530	$3,561,494	$567,284	$2,791,108	$2,036,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return (Line 7 Line 9) and Expenses (Line 6 + Line 11 + Line 15)	$2,690,175	$9,469,147	$3,561,494	[illegible]	[illegible]	[illegible]	$1,930,370	$736,643	$291,249	$180,764	$837,791	$19,663,406
17)	Less: Revenue Credits	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$0	$0	$0	[illegible]
18)	**REVENUE REQUIREMENT @-6.04%**	**$2,291,602**	**$6,795,153**	**$2,714,426**	[illegible]	[illegible]	[illegible]	**$1,929,907**	**$714,533**	**$291,249**	**$180,764**	**$833,791**	**$14,088,395**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs ($cents/kWh)**	**0.0086**	**0.0252**	**0.0102**	**-0.0006**	**-0.0025**	**-0.0023**	**0.0072**	**0.0027**	**0.0011**	**0.0004**	**0.0031**	**0.0527**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$7.05**	**$20.73**	**$8.35**	**-$0.70**	**-$2.07**	**-$1.92**	**$5.94**	**$2.20**	**$0.90**	**$0.31**	**$2.57**	**$43.36**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

		Unbundled Functional Revenue Requirement											
		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,389	$1,356,802		$6,216,972	$26,756,256	$20,811,249		$4,840,752			$3,019,457	$114,452,869
2)	Customer Accounts							$0					$2,023,953
3)	Cust. Service & Info and Sales Expense							1,794,234		107,677	121,842		
4)	Customer Deposits							$560,497					$560,497
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base				[illegible]	[illegible]	[illegible]						[illegible]
		$51,435,445	$1,356,802	$0	$6,102,496	$26,263,496	$20,427,943	$2,374,731	$4,840,752	$107,677	$121,842	$3,019,457	$116,052,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,546	$1,019,354	$118,499	$241,554	$5,363	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.15%												
11)	Income Taxes (Line 7 Line 9) Line 6) Line 10) Line 15)	$790,893	$21,074	$0	$94,788	$407,925	$317,286	$36,864	$75,146	$1,670	$1,892	$46,849	$1,802,496
	Expenses												
12)	Expenses	10,277,250	9,637,530	[redacted]	567,284	2,791,108	2,036,147		1,337,751			1,208,737	$31,419,401
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,535					$700,535
15)	Total Expenses	$10,277,250	$9,637,530	$3,561,494	$567,284	$2,791,108	$2,036,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return (Line 7 Line 9) and Expenses (Line 6 + Line 11 + Line 15)	$13,642,772	$9,726,408	$3,561,494	$988,580	$4,509,580	$3,374,787	$2,369,639	$1,654,491	$311,701	$123,866	$1,406,306	$41,667,625
17)	Less: Revenue Credits	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$0	$0	$0	[illegible]
18)	**REVENUE REQUIREMENT @4.99%**	**$12,944,369**	**$6,992,414**	**$2,714,426**	**$981,180**	**$4,507,749**	**$3,348,259**	**$2,079,679**	**$1,622,481**	**$311,701**	**$123,866**	**$1,408,306**	**$38,903,804**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs ($cents/kWh)**	**0.0481**	**0.0262**	**0.0102**	**0.0036**	**0.0101**	**0.0122**	**0.0080**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1451**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.67**	**$21.91**	**$8.35**	**$2.87**	**$13.39**	**$10.00**	**$7.32**	**$5.02**	**$0.96**	**$0.36**	**$4.33**	**$111.07**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$30.01**	**$0.78**	**$0.00**	**$3.58**	**$15.53**	**$11.82**	**$1.38**	**$2.82**	**$0.06**	**$0.07**	**$1.76**	**$67.71**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Demand Rates - 9/TE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,466	$93,321		$363,088	$1,648,723	$1,164,809	$0	$210,234			$207,678	$8,998,345
2)	Customer Accounts							$77,824		$4,665	$5,290		$87,801
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				[illegible]	[illegible]	[illegible]						[illegible]
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,665	$5,290	$207,678	$8,477,364
7)	Actual Earned ROR @ 0.79%												
8)	Return on Rate Base (Line 6 * Line 7)	$25,987	$737	$0	$2,900	$12,483	$8,816	$815	$1,661	$37	$42	$1,641	$66,121
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.56%												
10)	Tax Rate @ 38.19%												
11)	Income Taxes (Line 7 Line 9 Line 8) Line 10)/(1-Line 10)	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Expenses												
12)	Expenses	$651,121	$878,242	$241,673	$41,673	$17,988	$113,594		$58,089			$83,137	$2,237,527
13)	Customer Accounts							$56,609		$13,231	$5,033		$94,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$878,242	$241,673	$41,673	$17,988	$113,594	$103,683	$58,089	$13,231	$5,033	$83,137	$2,379,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$676,180	$879,000	$241,673	$45,338	$196,242	$126,535	$113,908	$57,338	$13,214	$5,014	$82,982	$2,344,103
17)	Less: Revenue Credits	[illegible]	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$0	$0	[illegible]
18)	**REVENUE REQUIREMENT @6.79%**	**$616,408**	**$872,035**	**$144,224**	**$40,338**	**$184,201**	**$87,866**	**$104,270**	**$53,880**	**$12,364**	**$5,014**	**$82,982**	**$1,867,875**
19)	**Energy Consumption (MWh)**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**
20)	**Functional Unit Costs (kwh/kWh)**	**0.0294**	**0.0042**	**0.0073**	**0.0020**	**0.0093**	**0.0049**	**0.0064**	**0.0027**	**0.0006**	**0.0005**	**0.0042**	**0.0094**
21)	**Number of Customers**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**
22)	**Functional Unit Costs ($/Customer/month)**	**$36.01**	**$47.70**	**$10.22**	**$2.87**	**$11.03**	**$6.98**	**$7.85**	**$3.82**	**$0.87**	**$0.36**	**$5.84**	**$134.48**

Residential Solar @ Targeted ROR (Demand Rates - 9/TE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,466	$93,321		$363,088	$1,648,723	$1,164,809		$210,234			$207,678	$8,998,345
2)	Customer Accounts							77,824		4,665	5,290		$87,801
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				[illegible]	[illegible]	[illegible]						[illegible]
5)	Customer Advances	[illegible]			[illegible]	[illegible]	[illegible]						[illegible]
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,665	$5,290	$207,678	$8,477,364
7)	Targeted ROR @ 4.90%												
8)	Return on Rate Base (Line 6 * Line 7)	$161,146	$4,457	$0	$18,000	$78,847	$56,778	$5,140	$10,491	$234	$264	$10,383	$346,172
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.56%												
10)	Tax Rate @ 38.19%												
11)	Income Taxes (Line 7 Line 9 Line 8) Line 10)/(1-Line 10)	$51,092	$1,440	$0	$5,702	$24,542	$17,934	$1,622	$3,295	$73	$82	$3,229	$108,371
	Expenses												
12)	Expenses	$651,121	$878,242	[redacted]	$41,673	$17,988	$113,594		$58,089			$83,137	$2,237,527
13)	Customer Accounts							$56,609		$13,231	$5,033		$94,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$878,242	$241,673	$41,673	$17,988	$113,594	$103,683	$58,089	$13,231	$5,033	$83,137	$2,379,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$865,358	$883,340	$241,673	$65,396	$275,377	$188,306	$120,431	$71,895	$13,538	$5,379	$96,729	$2,829,014
17)	Less: Revenue Credits	[illegible]	[illegible]	[illegible]	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$0	$0	[illegible]
18)	**REVENUE REQUIREMENT @4.90%**	**$746,604**	**$870,379**	**$144,224**	**$66,594**	**$275,180**	**$174,201**	**$113,401**	**$68,200**	**$12,882**	**$5,379**	**$96,729**	**$2,579,869**
19)	**Energy Consumption (MWh)**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**	**10,002**
20)	**Functional Unit Costs (kwh/kWh)**	**0.0370**	**0.0046**	**0.0073**	**0.0033**	**0.0138**	**0.0084**	**0.0058**	**0.0035**	**0.0006**	**0.0005**	**0.0048**	**0.1289**
21)	**Number of Customers**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**	**1,170**
22)	**Functional Unit Costs ($/Customer/month)**	**$52.91**	**$48.13**	**$10.22**	**$4.69**	**$19.50**	**$12.34**	**$8.04**	**$4.83**	**$0.90**	**$0.38**	**$6.85**	**$186.01**
23)	**Under Recovery (Targeted less Actual)($/Customer/month)**	**$16.91**	**$0.44**	**$0.00**	**$1.80**	**$7.75**	**$5.46**	**$0.19**	**$1.05**	**$0.02**	**$0.03**	**$1.02**	**$51.13**

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.4: Regarding APS's Response to VS 1.1:

Please provide the following information regarding VS 1.1_2014 COS Load Data_APS15747.xlsm.

a) Please describe the methodology APS used for the load data analysis.

b) Please indicate whether the load data shown for solar customers is the result of a statistical sampling of a subset of actual APS solar customers. If so, please describe the sampling methodology and indicate what proportion of APS solar customers were included in the sample. If not, please describe the derivation of the solar customer load data.

c) Please describe the meaning of the following terms as used in the titles of the spreadsheet tabs: "No Solar," "Solar Delivered," "Solar Site," "Solar Del," and "Solar Net."

Response:

a.) APS queries its energy data "warehouse" for all Residential AMI interval data. The AMI data is then sorted into the corresponding rates and categories (i.e. "No Solar", "Solar Delivered", "Solar Site", and "Solar Net"). A mean-per-unit analysis technique is then used to obtain the peak values for the report.

b.) APS's load data shown for solar customers is based on all solar customers' interval data.

c.) Term Definitions are as follows:

- *No Solar* – measured energy delivered from APS to customers who are not on a solar rate.
- *Solar Del / Solar Delivered* – measured energy delivered from APS to customers on a solar rate.
- *Solar Site* – the energy used by a customer based on the following formula: [Delivered Electricity + (Produced Electricity – Received Electricity)], where Delivered Electricity means energy delivered from APS to the customer and Received Electricity means energy delivered from the customer to APS.
- *Solar Net* – the energy used by a customer based on the following formula: [Delivered Electricity – Received Electricity].

Exhibit WAM-4: Excerpt from
"Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures,"
National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015

Effects of Home Energy Management Systems on Distribution Utilities and Feeders under Various Market Structures

Preprint

Mark Ruth, Annabelle Pratt, Monte Lunacek, Saurabh Mittal, Hongyu Wu, and Wesley Jones
National Renewable Energy Laboratory

Presented at the 23rd International Conference on Electricity Distribution
Lyon, France
June 15–18, 2015

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

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Conference Paper
NREL/CP-6A20-63500
July 2015

Contract No. DE-AC36-08GO28308

controllers and custom reduced-order building models [10]. The model predictive controllers were also only run once per day, and a real-time price was provided as an input, based on historical CAISO prices and weather.

In this paper, we describe the IESM's structure. We then define the scenario used in the analysis; report results on the impact of HEMS technology on a feeder; and provide conclusions and propose future work.

INTEGRATED ENERGY SYSTEM MODEL

The Integrated Energy System Model (IESM) is being developed to analyze interactions between multiple technologies within various market and control structures, and to identify financial and physical impacts on both utilities and consumers. Physical impacts include both consumer comfort (e.g., difference between actual and desired temperature) and distribution feeder operations including voltage profiles and equipment loading. In addition, the IESM will be dynamically integrated into hardware in the loop (HIL) testing of technologies in the National Renewable Energy Laboratory's (NREL's) Energy Systems Integration Facility (ESIF) by providing market signals to technologies and equipment.

To meet these objectives, the IESM is being designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure. The IESM uses co-simulation, wherein multiple simulators with specific modeling capabilities co-operate towards a common objective of bringing the capabilities together in a shared execution environment, and manages time and data exchange between component models. The co-simulation execution is performed on a high-performance computer (HPC).

In the current version, GridLAB-D, which performs distribution feeder, household, and market simulations, is co-simulated with Pyomo [11], which implements a HEMS for each household. GridLAB-D is an agent-based, open source power system simulation tool developed by the Pacific Northwest National Laboratory. It performs quasi-steady state simulations for distribution feeders, including end-use loads such as heating-cooling systems, water heaters and electric vehicles. It also manages retail markets and responses to market signals [8]. Similar to [10], the wholesale market is not included.

The IESM can include both price responsive thermostats, responding to the current price, and model predictive controllers which can be run several times during the day, which models the operation of such devices more realistically. In the reported case, the IESM utilizes HEMS, implemented in Pyomo, minimizes its house's cooling cost using a model predictive control approach and sets the cooling setpoint to a calculated optimal value while constrained by an envelope around the desired temperature [12]. No custom HVAC model was developed for the HEMS, instead, through the IESM's co-simulation structure, models available in existing software simulation packages are accessed.

Ultimately, the IESM will utilize an internal discrete event coordinator that operates on abstract time and an enterprise message bus as shown in Figure 1. The scheduler is expected to manage GridLAB-D's simulation of distribution feeders; actual or simulated loads and DER either in experimental hardware, GridLAB-D, or another simulation package such as Energy Plus [13]; and simulation of technologies, such as HEMS, markets, and consumers. Component libraries allow the creation of comprehensive scenarios, including different types of houses and market structures in a plug-and-play component-based manner.

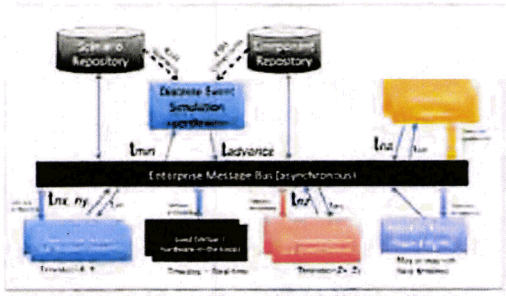

Figure 1. Integrated Energy System Model (IESM) architecture

SCENARIO DEFINITION

A scenario was created for a distribution feeder in the state of North Carolina in the Southeast of the United States in the summer for the month of July when air conditioning use is high. A distribution feeder based on the IEEE 13-node test feeder is used and about 3% of the load is replaced with houses in order to provide a price-responsive, varying load component [14].

The feeder is populated with 20 well-insulated houses with identical parameters, which are connected through four 25 kVA single-phase, center-tapped transformers – each serving 5 houses. The air conditioner in the house is modeled explicitly, and the rest of the household loads are modelled as a lumped ZIP load with a time-varying base power profile. The desired cooling temperature profile is motivated by EPA's Energy Star Recommendations [15]. The desired profile for each house is different, as shown in Figure 2. Each house has a desired daytime temperature between 72° and 77° F (22.2-25.0°C) that is set at uniformly distributed random time between 4:00 AM and 8:00 AM. The desired daytime temperature is constant for 16 hours and is set back by 3°F (1.7°C) at night for 8 hours. Each household's ZIP load base power profile has the same shift in time as the desired temperature.

Two retail electricity tariff structures that are currently in place for households in North Carolina are used. The first has a flat structure with a constant electricity price of $0.093587/kWh and a monthly service fee of $11.80 [16]. The TOU rate structure is shown in Figure 3. It has a varying electricity price with peak, shoulder, and off-peak rates and a monthly service fee of $14.13. The peak, shoulder, and off-peak rates are $0.2368/kWh,

$0.11961/kWh, and $0.06936/kWh, respectively. Summer peak hours are 1:00 PM to 6:00 PM, Monday through Friday and shoulder rates are in effect during the two hours before and after the peak hours [17]. All weekend hours are off-peak. Vertical shaded areas in this and other figures indicate peak and should pricing time periods.

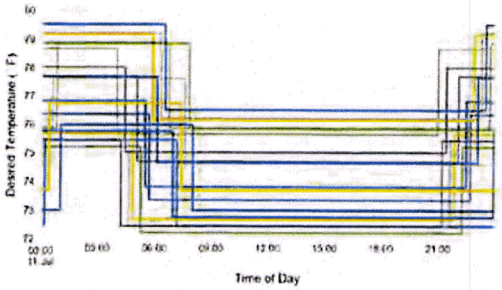

Figure 2. Desired temperature profile for each of the houses in the simulation. Daytime temperatures are randomly distributed between 72 and [illegible] (22.2-25.0°C), set at a random time between 4:00 and 8:00 AM. After 16 hours, the desired temperature increases by 3°F (1.7°C).

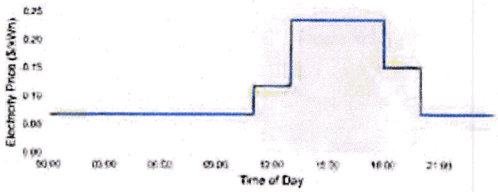

Figure 3. Time-of-use pricing profile for weekdays. All weekend hours are off-peak and have the lowest price

Three HEMS penetrations (0%, 50%, and 100%) are simulated to show how IESM can be used to evaluate the physical and financial impacts of distributed technologies, such as HEMS, in the presence of different markets or tariffs, on the system. Each house's HEMS uses model predictive control to adjust the cooling setpoint from the desired temperature to minimize cost. The HEMS does not allow the setpoint to be above the desired temperature, but does allow it to be down to 5°F (2.8°C) below the desired temperature so that the house can be precooled before peak electricity prices.

RESULTS

Figure 4 shows the range of electricity expenses for the households in the population. Those expenses vary because of variations in desired temperatures and their profiles between houses. For the time period analyzed, the uniform tariff has a lower cost than TOU due to high demand for cooling and other loads during peak hours. Presumably, that load will not be as large at other times of the year and bills under TOU tariffs will be lower during those seasons. Under TOU tariffs, bills are about 5% lower when HEMS are used to manage cooling.

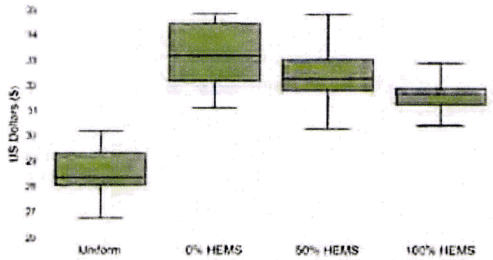

Figure 4. Box plot of the population's electricity bills over the time period from July 7-17, 2012. Use of HEMS reduces each household's bill by about 5%.

Cost savings are driven by the use of power during off-peak and shoulder times for precooling the houses. Figure 5 displays the total cooling power of all the houses over each day with vertically shaded bars indicating peak-price hours and shoulders. The solid lines display the mean total cooling loads over all 11 days, and the shaded areas indicates a 95% confidence interval. Results for the uniform price distribution are identical to the scenario with 0% HEMS penetrations.

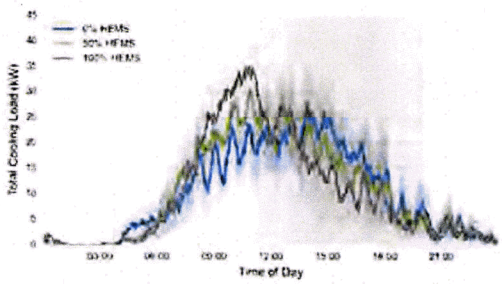

Figure 5. Daily profile of total cooling power load at several levels of HEMS penetrations. When HEMS are present, power use is shifted from peak hours to earlier times when it is less expensive.

When HEMS are present, power use is shifted from times when cost is higher (peak-price periods from 1:00 PM to 6:00 PM) to earlier hours when it is not as expensive. In addition, with the HEMS penetration levels simulated here, the peak is higher during the time period before prices increase than at any time without HEMS. The HEMS used in this study does not adjust any other household loads so they are not shifted due to pricing.

Figure 6 shows the total load on the distribution transformers. The solid line shows the mean and the shaded area shows a 95% confidence interval. The peak load during peak pricing is reduced with the HEMS penetration levels simulated here, but a new, higher peak load is created during the time period before peak pricing. Because the peak load is just shifted, the distribution feeder still experiences peak stress even though the TOU rate structure was likely designed to reduce the peak load.

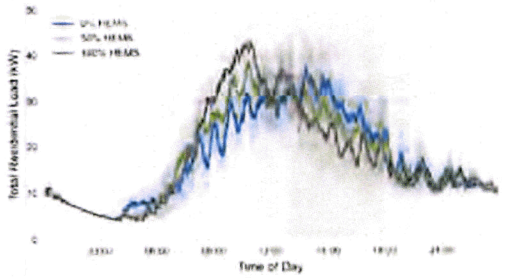

Figure 6. Daily profile of the total distribution transformer load with several HEMS penetrations. Presence of HEMS reduces the peak load during peak pricing but creates a new peak load in the time period before peak pricing is in effect.

Using power to precool intrinsically indicates that the house's temperature setpoint is lower than desired for a time before the peak pricing period. Figure 7 shows the daily profile of the population's average temperature over all days with and without HEMS. The solid line shows the mean and the shaded area shows a 95% confidence interval. The average of the population with HEMS precools by almost 2°F (1.2°C) as compared to the population without HEMS (i.e., without cost optimization). Note that the starting time for cooling is consistent because the two populations have the same time for the initial house's change in desired temperature and, during that time, the setpoint for both is the desired temperature.

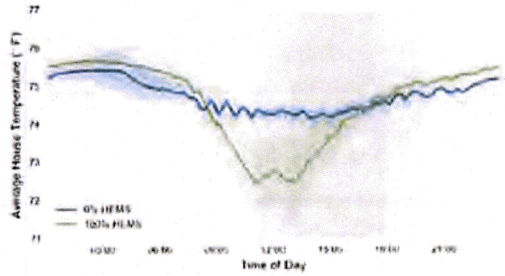

Figure 7. Daily profile of mean household temperature for the population with and without HEMS. HEMS minimize cost by precooling by about 2°F (1.1°C) before peak pricing is in place.

Figure 8 shows the daily profile of the primary voltage of the distribution transformer at node 652. It serves five houses. The solid lines display the mean and the shaded area indicates a 95% confidence interval. With HEMS, the lowest voltage is experienced at an earlier time in the day, coinciding with the peak transformer load moving earlier due to precooling. The minimum voltage is lower in this case, due to the fact that the peak transformer load is higher with HEMS than without. Overall the voltage variation is small due to the fact that only a small percentage of the load at this node is replaced with houses that provide a time-varying load component.

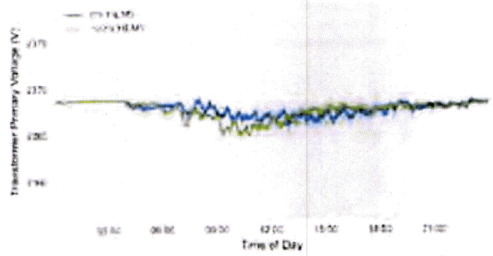

Figure 8. Daily profile of primary voltage of the transformer at node 652 and serving five houses. Use of HEMS shifts time of low voltage to coincide with new peak introduced by HEMS.

Utility net revenue is calculated as the difference between income from the household electricity bills reported above and the wholesale cost of the electricity provided. The wholesale cost of the electricity is calculated as the product of the total electricity demand for the feeder and the Midcontinent Independent Service Operations hourly real-time locational marginal prices for a hub in North Carolina (price node 746136) and are assumed to be unaffected by the modelled changes in the load.

Table 1: Comparison of household expenditures and utility net revenue between scenarios

	Sum of household expenditures	Utility net revenue
Uniform rate	$573	$470
TOU rate – 0% HEMS	$665	$562
TOU rate – 50% HEMS	$650	$547
TOU rate – 100% HEMS	$632	$530

Table 1 shows the utility net revenue and the total household expenditure for the four scenarios. Utilizing HEMS reduces the sum of household expenditures by $33 in the time period analyzed, but only reduces the utility net revenue by $32. Where bulk power prices are unaffected by load, utility net revenue is reduced by approximately the same amount as household expenditure reductions; thus, indicating that the TOU rate structure provides similar net revenue at all times.

CONCLUSIONS AND FUTURE WORK

This paper presented results from a specific scenario simulated using a co-simulation platform, the Integrated Energy System Model (IESM), under development to study the physical and economic impact of distributed technologies under different markets or tariff structures.

The results reported here show that the combination of time-of-use (TOU) pricing and Home Energy Management Systems (HEMS) controlling residential cooling systems reduces peak load during high price hours but moves the load peak to hours with off-peak and shoulder prices. This situation would be further exacerbated with HEMS that are able to shift the operation of multiple loads within a household in

Exhibit WAM-5: Excerpt from
"Energy Star: Program Requirements for Programmable Thermostats,"

ENERGY STAR® Program Requirements for Programmable Thermostats

Partner Commitments
DRAFT 1

Commitment

The following are the terms of the ENERGY STAR Partnership Agreement as it pertains to the manufacturing of ENERGY STAR qualified programmable thermostats. The ENERGY STAR Partner must adhere to the following program requirements:

- comply with current ENERGY STAR Eligibility Criteria, defining the performance criteria that must be met for use of the ENERGY STAR certification mark on programmable thermostats and specifying the testing criteria for programmable thermostats. EPA may, at its discretion, conduct tests on products that are referred to as ENERGY STAR qualified. These products may be obtained on the open market, or voluntarily supplied by Partner at EPA's request;

- comply with current ENERGY STAR Identity Guidelines, describing how the ENERGY STAR marks and name may be used. Partner is responsible for adhering to these guidelines and for ensuring that its authorized representatives, such as advertising agencies, dealers, and distributors, are also in compliance;

- qualify at least one ENERGY STAR qualified programmable thermostat model within one year of activating the programmable thermostat portion of the agreement. When Partner qualifies the product, it must meet the specification (e.g., Tier 1 or 2) in effect at that time;

- provide clear and consistent labeling of ENERGY STAR qualified programmable thermostats. The ENERGY STAR mark must be clearly displayed on the front/inside of the product, on the product packaging, in product literature (i.e., user manuals, spec sheets, etc.), and on the manufacturer's Internet site where information about ENERGY STAR qualified models is displayed;

> **Note:** EPA requires the labeling of all ENERGY STAR qualified products according to one or more of the following options, depending on product design and visibility at both the time of sale and over the use of the product: on the product; in product literature; and on the manufacturer's Internet site. The ENERGY STAR mark is well known by consumers and large purchasers as the symbol for energy efficiency. The ENERGY STAR mark should be placed in an area of high visibility, preferably on front of the product, so that the purchaser and end users can see that by purchasing and using an ENERGY STAR qualified programmable thermostat, they are helping to reduce air pollution and greenhouse gases through energy efficiency. EPA is open to discussing additional placement options.

- provide to EPA, on an annual basis, an updated list of ENERGY STAR qualifying programmable thermostat models. Once the Partner submits its first list of ENERGY STAR qualified programmable thermostat models, the Partner will be listed as an ENERGY STAR Partner. Partner must provide annual updates in order to remain on the list of participating product manufacturers;

- provide to EPA, on an annual basis, unit shipment data or other market indicators to assist in determining the market penetration of ENERGY STAR. Specifically, Partner must submit the total number of ENERGY STAR qualified programmable thermostats shipped (in units by model) or an

1. **Default Program.** The setbacks and setups periods are required to be a minimum of 8 hours, but may exceed 8 hours. Partners must have four events on the weekday and two on the weekend, partners may choose to add additional setbacks and/or setups as long as the setback/setup period is at least eight-hours long. Listed below are the suggested events along with setbacks/setups and appropriate temperatures (Tables 1-3).

Table 1: Programmable Thermostat Setpoint Temperatures

Events	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Day	setback at least 8°F (4.4°C)	setup at least 8°F (3.8°C)
Evening	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Night	setback at least 8°F (4.4°C)	setup at least 3°F (2.2°C)

Table 2: Acceptable Weekday Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	6 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	8 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	10 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Table 3: Acceptable Weekend Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	8 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	10 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	11 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Exhibit WAM-6: Excerpt from

Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Hardware Design of Smart Home Energy Management System With Dynamic Price Response

Qinran Hu, *Student Member, IEEE*, and Fangxing Li, *Senior Member, IEEE*

***Abstract*—The smart grid initiative and electricity market operation drive the development known as demand-side management or controllable load. Home energy management has received increasing interest due to the significant amount of loads in the residential sector. This paper presents a hardware design of smart home energy management system (SHEMS) with the applications of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can easily achieve a real-time, price-responsive control strategy for residential home loads such as electrical water heater (EWH), heating, ventilation, and air conditioning (HVAC), electrical vehicle (EV), dishwasher, washing machine, and dryer. Also, consumers may interact with suppliers or load serving entities (LSEs) to facilitate the load management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then a machine learning algorithm is applied to intelligently help consumers reduce total payment on electricity without or with little consumer involvement. Finally, simulation and experiment results are presented based on an actual SHEMS prototype to verify the hardware system.**

***Index Terms*—Controllable load, demand response, dynamic pricing, embedded system, machine learning, optimal control strategies, peak shaving, remote operation, smart home energy management system (SHEMS).**

NOMENCLATURE

F_i	Signals from sensors.
C	User's activity.
$X_T(t)$	Temperature in electrical water heater at time t, °C.
$X_a(t)$	Ambient temperature at time t, °C.
a	Thermal resistance of tank walls, W/°C.
$A(t)$	Rate of energy extraction when water is in demand at time t.
$q(t)$	Status of the hot water demand at time t, ON/OFF.
P_{EWH}	Power rating of the heating element, W.
P_{EV}	Power rating of charging station, W.
P_H	Power rating of dishwasher, washing machine, or dryer, W.
$m(t)$	Thermostat binary state at time t, ON/OFF.
$RTP(t)$	Real time price at time t, $/MWh.
$S_{EV}(t)$	Status of charging station, ON/OFF.
TF_{EV}	The time EV needs to get fully charged (hour).
R_{EV}	Desired percentage of battery being charged.
T_{start}	The time when EV is connected to charging station.
T_{end}	The time when the user needs to drive EV.
T_{hstart}	The time when dishwasher, washing machine, or dryer starts to work.
T_{huse}	Time duration for dishwasher, washing machine, and dryer to complete the work once started.
T_{hready}	The time when dishwasher, washing machine, and dryer is ready to use.
T_{hend}	The time when the user needs to pick up things from the dishwasher, the washing machine or the dryer.

Manuscript received October 14, 2012; revised February 26, 2013 and April 04, 2013; accepted April 04, 2013. Date of publication June 06, 2013; date of current version November 25, 2013. This work was supported by the NSF under Grant ECCS 1001999. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program. Paper no. TSG-00720-2012.

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Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSG.2013.2258181

I. INTRODUCTION

THE electricity prices in a competitive power market are closely related to the consumers' demand. However, the lack of real-time pricing (RTP) technologies presents challenges to electricity market operators to optimally signal and respond to scarcity, because electricity cannot be stored economically [1]. In the past a few years, the deployment of advanced metering infrastructures (AMI) and communication technologies make RTP technically feasible [2]. RTP, generally speaking, reflects the present supply-demand ratio and provides a means for load-serving entities (LSEs) and independent system operators (ISOs) to solve issues related to demand side management such as peak-load shaving. Applications of RTP enable consumers and suppliers to interact with each other, which also creates an opportunity for consumers to play an increasingly active role in the present electricity market with optimal control strategies at the demand side.

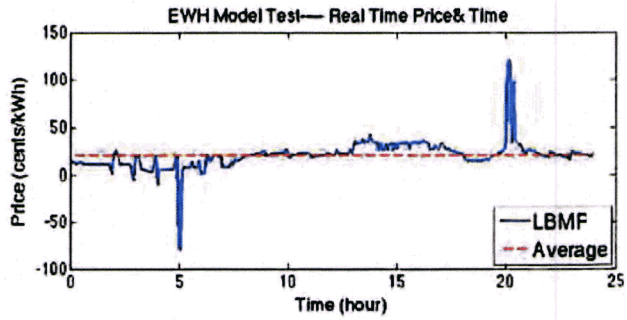


Fig. 11. Real time price curve for 24 hours.

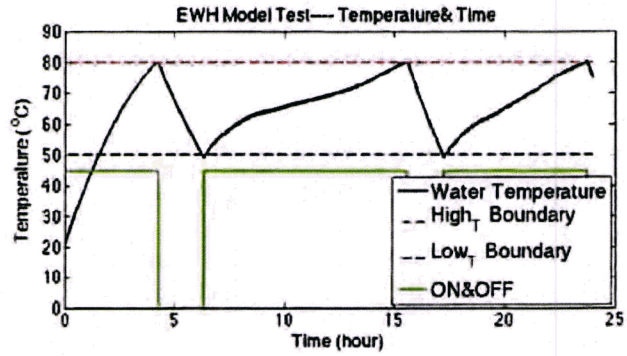


Fig. 12. Typical EWH strategy [26].

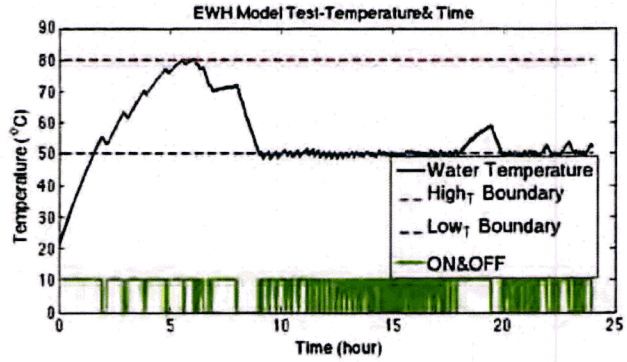


Fig. 13. Optimized EWH strategy.

signal may change as fast as every 5 minutes which is a discrete variable. The model can be described by:

$$\frac{dX_T}{dt} = -a\left(X_T(t) - X_a(t)\right) - A(t)q(t) + P_{EWH} \cdot m(t) \quad (2)$$

Table II shows the specifications of EWH used in the experiment. For testing and simulation purposes, Table III shows some useful information applied here. Also, a typical water usage curve as shown in Fig. 10 is obtained from [25].

In this study, the locational marginal price (LMP) on a randomly selected day from NYISO is used as the real-time price, which is shown in Fig. 11. The result without SHEMS is shown in Fig. 12, and the results after applying an RTP-responsive algorithm to change the ON and OFF strategy of EWH is shown in Fig. 13.

The optimized strategy used in the test can be further improved in future algorithm/software studies, while this paper focuses on the hardware part. Nevertheless, the straightforward algorithm still works greatly. A brief description of the algorithm is presented next.

The principle of the algorithm is to turn EWH on for a while before the dropping temperature reaches the lower bound. Meanwhile, the algorithm also considers whether the EWH can provide comfortable hot water based on the predicted consumer demand of water usage with a look-ahead consideration. For example, the algorithm will preheat the EWH to a higher temperature before the consumer takes a shower. The mathematical description is an optimization model given below.

$$\min \int_0^{24} RTP(t) \cdot m(t) \cdot P_{EWH} \quad (3)$$

$$\text{s.t.}: \quad \text{Eq. (2)}$$

$$T_{low} \leq X_T(t) \leq T_{high} \quad (4)$$

Since $RTP(t)$ refreshes every 5 minutes, this model given by (2), (3), and (4) is discretized into a time interval of 5 minutes. The genetic algorithm (GA), an intelligent search algorithm using stochastic operations, is customized in this work to solve the model to find the global optimal scheduling for the EWH. With this approach, SHMES can reduce the total payment and energy consumption while meeting the consumer's needs.

The result verifies that SHEMS helps reduce the thermostat ON time by 14%, while reducing the consumer's payment by 60% of the original payment on heating water.

The proposed SHEMS system has been programmed and tested to connect and disconnect a mock EWH load in accordance with Fig. 13.

B. Heating, Ventilation, and Air Conditioning (HVAC)

The American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) has compiled modeling procedures in its Fundamentals Handbook [27]. The Department of Energy has produced the Energy Plus program for computer simulation [28]. Also, the detailed model for simulating HVAC systems is given in [29], [30]. Accurate model for energy consumption needs to consider many factors including weather, season, thermal resistance of rooms, solar heating, cooling effect of the wind, and shading. Unlike EWH which has constant and relatively accurate parameters, those HVAC parameters are difficult to be precisely modeled with the possibility to change over the time due to other factors.

Thus, the testing here is not based on any detailed model but relies on the actual measurement from the experiments performed at the University of Tennessee with the SHEMS prototype and a portable HVAC unit.

In this experiment, the SHEMS optimizes the HVAC based on three parameters: the mock RTP from the prices in a randomly selected day in NYISO used in the previous EWH test, the real-time temperature in the test room, and the temperature setting by the user. Table IV shows the related parameters.

For comparison purpose, a parameter named "Comfort Level" is considered here. In market economics, a consumer has to compromise between quality and price. The introduction of "Comfort Level" is based on similar idea for home energy management. Simply speaking, "Comfort Level" in this case

TABLE IV
HVAC PARAMETERS IN THE TEST

Room Area	800 sq ft
Room Type	Single room
HVAC Power Rate	3.5kW
Room Temperature Setting	73°F (23°C)

TABLE V
HVAC RESULTS WITH SHEMS

	Different Comfort Level		
	+/- 0°C	+/- 3°C (5.8°F)	+/- 5°C (9°F)
Energy Consumption (% w.r.t the case w/o SHEMS)	91%	79%	72%
Payment (% w.r.t the case w/o SHEMS)	86%	73%	64%

means the difference between the actual indoor temperature and the temperature desired by the consumer.

Table V shows the energy consumption and the total payment reduction of the cases under different comfort levels with SHEMS. The results are in percentage with respect to the case without SHEMS. As shown in the table, considerable reduction of energy consumption and payment is achieved. Further, if a consumer can tolerate a higher temperature difference, more payment or credit to HVAC from the supplier can be achieved. This is sensible from the standpoint of market economics.

C. EV, Dishwasher, Washing Machine and Dryer

In order to fully exploit the potential of SHEMS and contribution to the power grid, low cost is an important characteristic of the prototype. Since considering bidirectional power flow will significantly increase the total cost of SHEMS design, the electric vehicle (EV) model in the proposed prototype is to charge a battery. That is, this design of SHEMS does not include the consideration for EV to send power back to grid.

Loads such as charging the battery for an EV are interruptible [15]. It is possible to charge the battery for 1 h, then stop charging for another hour, and then finish the charging after that. In contrast, the loads like dishwasher, washing machine and dryer demonstrate similar features to EV, but differ from EV considerably because they are uninterruptible. That is, as soon as the corresponding appliance starts operation, its operation should continue till completion.

1) Electrical Vehicles: An EV should be fully charged, for example, at 8 A.M. but the EV user does not care when or how the EV battery is charged. Therefore, SHEMS chooses the possible hours with the low electricity price to charge. Meanwhile, SHEMS must make sure EV to be fully charged before being used at 8 A.M..

As an interruptible load, the mathematical expression of the discrete model of EV can be expressed in (5) and (6). Since the real-time price refreshes every 5 minutes, the time interval of discrete model is also set to 5 minutes. Here, $S_{EV}(t)$ is the optimal solution that needs to be generated by SHEMS.

TABLE VI
PARAMETERS OF DISHWASHER, WASHING MACHINE, AND DRYER

	Model	P_H (W)	T_{huse} (min)
Dishwasher	Danby	1000	30
Washing machine	Danby	400	45
Dryer	Whirlpool	3000	40

$$\min \sum_{t=T_{start}}^{T_{end}} P_{EV} \cdot RTP(t) \cdot S_{EV}(t) \tag{5}$$

$$\text{s.t.}: \frac{1}{12} \cdot \sum_{t=T_{start}}^{T_{end}} S_{EV}(t) = TF_{EV} R_{EV} \tag{6}$$

2) Dishwasher, Washing Machine, and Dryer: As an uninterruptible load, the mathematical expression of the discrete model of dishwasher, washing machine and dryer can be all expressed in (7), (8), and (9), respectively. The time interval of discrete model is also set to 5 minutes. T_{hstart} is the optimal solution which needs to be generated by SHEMS.

$$\min \sum_{t=T_{hstart}}^{T_{hstart}+T_{huse}} P_H \cdot RTP(t) \tag{7}$$

$$\text{s.t.}: T_{hready} \leq T_{hstart} \leq T_{hend} \tag{8}$$

$$T_{hready} \leq (T_{hstart} + T_{huse}) \leq T_{hend} \tag{9}$$

D. Effects of SHEMS in Load Shifting

Based on the previous analysis on EWH and HVAC, it is rational to conclude that SHEMS can make substantial contribution to reduce home energy consumption from not only EWH and HVAC but also EV, dishwasher, washing machine, dryer, etc. To study the effect of SHEMS in a large-scale system, this section demonstrates a comparison on the load curves with and without SHEMS.

The simulation here is to give a quantified verification that SHEMS will play a critical role in load shifting. The total real-time load curve (including residential, commercial, industrial and other) is selected from NYISO again. The date of the data is the same as the date of the selected RTP.

The EWH and HVAC parameters are the same as from the previous Sections V-B and V-C. The EV parameters are chosen based on Nissan Leaf [31] for this simulation study:

- Charging power rate: approx. 6 kW;
- Battery volume: 24 kWh;
- Time of fully charging: 4 hour; and
- The percentage of EV battery to be charged is set as 100%.

The parameters of dishwasher, washing machine, and dryer are shown in Table VI.

The reduction of energy consumption from individual appliance is scaled up to simulate the optimized residential load consumption. The results are shown in Fig. 14, which illustrates that SHEMS can help with load shifting. In addition, it reduces the loads in peak hours by nearly 10 percent which is significant.

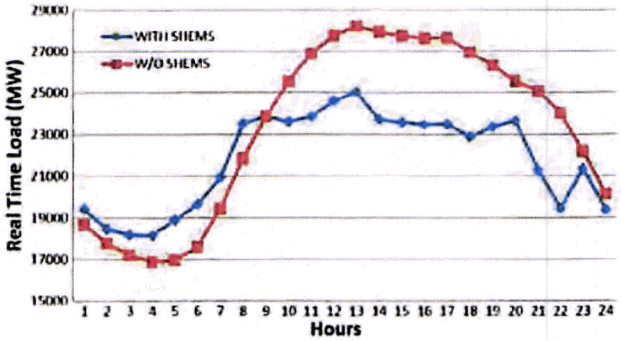


Fig. 14. Load curve comparison with and without SHEMS.

VI. Comparative Analysis and Conclusion

A. Comparative Analysis

As mentioned in the Introduction, there are several companies working on products related to demand response. However, those early products do not take full considerations of all aspects mentioned in this paper. Most of these previous products focus on displaying and monitoring the status of home energy consumption. Some advanced ones may help analyze power usages of different appliances, then offer tips for conserving energy and reducing payment in electricity, which is represented by the "Indirect Feedback" [32], [33]. None of those previous works has reported any real intelligent control down to the appliance level, and users' interaction is needed. However, the proposed design and the actual prototype carried out in our Smart Home lab implements automated, intelligent controls for smart home energy management to the appliance level.

As for the cost, the proposed design typically costs less than $200 with off-the-shelf retail prices for materials and components. The actual cost also depends on the number of appliances that consumers want to install load interfaces, as well as the number of rooms to be monitored. Here is the cost breakdown in a typical case. The main controller costs around $80 based on to the off-the-shelf retail price($15 for a microcontroller, $20 for making PCB and accessories, $15 Wi-Fi module, and $30 for touch screen). Each load interface and room monitoring unit costs around $20 ($15 for Wi-Fi module and $5 for accessories). With the assumption that a consumer wants to control HVAC and EWH, and has 3~4 rooms to monitor, the total cost will be around $200 in this typical setting. In addition, this design is expandable and can be easily upgraded by updating programs running in the processor without any change of existing hardware.

Table VII provides a high-level comparison of the proposed design and 4 SHEMS-like devices from commercial vendors. These 4 devices include Monitor12 by Powerhouse, Home monition and Control by Verizon, Nucleus by GE, and Thermostat controller by NEST. The listed features are monitoring, remote control, real-time price responsive, machine learning, and easy setting. They are randomly named Vendor 1 to 4 without any particular order in Table VII. One of the vendor's cost is the annual service cost, while the device is sold separately. The cost of the system from Vendor 1 is relatively low, but with relatively simple functions. It does not have machine learning algorithm and cannot provide optimized schedule for home appliances. Vendor 4 provides a fancy user interface which is easy and efficient, but cannot control appliances other than HVAC.

TABLE VII
Comparison of Existing SHEMS

Name	Appliances	Monitor /Control	Response	Learn	Easy Setting	Cost ($)
Proposed Design	Extendable	X	X	X	X	~200
Vendor 1	Vendor's own devices	X	X			199
Vendor 2	12 switches	X				1024
Vendor 3	Extendable	X				120/yr
Vendor 4	Thermostat	X		X	X	250

Note that the cost of the developed prototype may not be directly comparable with the costs of the four vendors' products since the cost of the developed prototype does not include labor cost and the expected profit. However, on the other hand, the prototype cost is based on retail prices of various materials and components, which are usually higher than wholesale prices under mass production. Nevertheless, the cost information is listed in Table VII for future references.

B. Conclusion

This paper presents a hardware design of a smart home energy management system (SHEMS) with the application of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can achieve a RTP-responsive control strategy over residential loads including EWHs, HVAC units, EVs, dishwashers, washing machines, and dryers. Also, they may interact with suppliers or load serving entities (LSEs) to facilitate the management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then apply machine learning algorithm to intelligently help consumers reduce total electricity payment without much involvement of consumers. In order to verify the effort, this paper also includes testing and simulation results which show the validity of the hardware system of the SHEMS prototype. The expandable hardware design makes SHEMS fit to houses regardless of its size or number of appliances. The only modules to extend are the sensors and load interfaces.

Also, if this design can be widely used in the future, the administrator-user structure will provide good potentials for electricity aggregators. Most likely, utilities may not be interested or motivated to administrate all individual, millions of end consumers directly and simultaneously. Therefore, electricity aggregators can play as agents between consumers and utilities. This business mode may facilitate the popularity of SHEMS or similar systems and create win-win results for all players.

Acknowledgment

The authors would like to thank NSF for financial support under Grant ECCS 1001999 to complete this research work. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program.

Exhibit WAM-7: Excerpt from

California Energy Markets, Issue No. 1379, April 1, 2016

AN INDEPENDENT NEWS SERVICE FROM ENERGY NEWSDATA

CALIFORNIA ENERGY MARKETS

♦ Friday, April 1, 2016 ♦ No. 1379 ♦

BILLBOARD No. 1379

Gas-Storage Reform Bill Moves Ahead in State Senate ..... [5]

Utilities Try Algae to Reduce Power Plant CO_2..... [6]

EPA Defends Clean Power Plan in Court Filing..... [7]

Developer: Deal Near for LNG Project That FERC Nixed..... [8]

FPPC Opens Investigation of Brown Aide ..... [8.1]

Bottom Lines: 'Cattle Call' Inappropriate for SGIP..... [9]

SDG&E Seeks OK of Storage, Efficiency Contracts..... [11.1]

Cal-ISO Board Approves Transmission Plan..... [14.1]

Stump's Cell-Phone Messages to Stay Secret ..... [17]

Enel Touts Solar-Geothermal Hybrid Power Plant..... [17.1]

Judge Rejects Referendum on Nevada NEM Rates..... [17.2]

Western Price Survey

Despite Rains, California Drought Persists ..... [10]

[1] CARB Sets Sights on Including International Offsets in Cap and Trade

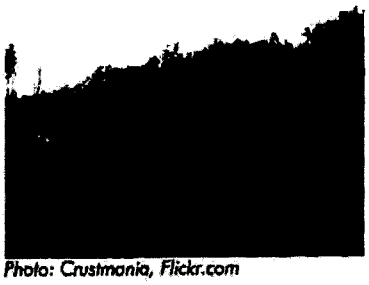


Photo: Crustmania, Flickr.com

The California Air Resources Board is considering whether to allow programs aimed at reducing GHG emissions from tropical deforestation to count as offset credits in the state's cap-and-trade program. Initiatives that prevent deforestation are a critical part of addressing global climate change, and may even provide for direct environmental benefits within California, according to CARB. Energy companies are advocating for additional sources of offsets, saying they are needed for cost containment. *Sinking carbon at [13].*

[2] Cal-ISO: Resources Adequate to Meet Summer Loads

Cal-ISO expects to have adequate resources to meet summer demand. Peak demand should be up slightly in 2016, based on projected economic growth and new behind-the-meter solar installations, while hydroelectric capacity is projected to be near normal for both spring and summer. Cal-ISO did warn, however, of possible natural gas curtailments related to the Aliso Canyon natural gas storage facility. Meanwhile, the growth of rooftop solar helped cancel transmission upgrades planned for the Pacific Gas & Electric service area. *At [14], generation and transmission.*

[3] CEC to Allow More Time for Puente Review

NRG Energy calls its Puente Power Project, a 262 MW natural gas plant proposed on the Southern California coast at Oxnard, "a bridge to California's energy future." Project opponents this week called for the California Energy Commission to allow more time to evaluate and comment on its environmental review of that "bridge." *At [11], the CEC says it plans to revise its proposed schedule for Puente.*

[4] Davis, Yolo County to Form JPA for Launch of CCA Program

The City of Davis and Yolo County have agreed to form a joint-powers authority that will administer a community choice aggregation program, with the launch of service expected in 2017. The CCA would serve electricity customers in Davis and unincorporated areas of the county, in competition with incumbent utility Pacific Gas & Electric. The door is open for other cities in Yolo County to join in the aggregation effort down the road. *At [15], stronger together?*

[14.1] Cal-ISO Board Approves Annual Transmission Plan

Thirteen new transmission projects with an estimated $288 million-dollar price tag were approved for construction by the Cal-ISO Board of Governors to ensure continued grid reliability.

According to the ISO's 2015-2016 Transmission Plan, each of the 13 projects costs less than $50 million and two-thirds are high-voltage upgrades needed to address reliability. None of the projects planned are policy- or economically-driven, which means there will be no need to take projects out for competitive bids, according to Cal-ISO, which approved the plan at its March 25 board meeting.

The transmission plan also called for canceling 13 sub-transmission projects in the Pacific Gas & Electric service area valued at $192 million. Some of these projects were originally approved in 2005. Of these, only two needed board approval—the Monta Vista-Wolfe and Newark-Applied Materials substation upgrades. Both 115 kV substation-upgrade projects were valued at $1 million each. However, Neil Millar, executive director of infrastructure development for Cal-ISO, said it is valuable "to get these cleared out of the way to focus on other projects going forward."

'We really appreciate the reappraisal of these projects.'

In his remarks to the board, Eric Eisenman, director of ISO relations and FERC policy for PG&E, conveyed the utility's support for the plan, including the project cancellations.

"The need for those is just not there anymore," he said. "We really appreciate the reappraisal of those projects." Load forecast has flattened in the service area from a combination of energy efficiency and rooftop solar, which eliminates the need for these upgrades, Eisenman said.

The utility plans to work with Cal-ISO on planning to prevent overbuilding and to ensure customers have affordable services. Future surveys, Eisenman said, would need to consider resources in the Oakland-East Bay area, which has an aging generation plant that may go off line. Roughly two-thirds of PG&E's $1 billion transmission budget is used to address maintenance and replacement of aging infrastructure.

This year's Cal-ISO transmission plan is "light" compared to previous plans, noted Steve Berberich, the grid operator's president and CEO, in his comments to the board. The 2012-2013 and 2013-2014 transmission plans were project-heavy to address issues in the PG&E service area and reliability requirements created by the early retirement of Units 2 and 3 of the San Onofre Nuclear Generating Station.

Among the new reliability projects identified in the 2015-2016 transmission plan are seven different projects, at a projected cost of $202 million, in the PG&E service area, including the reconductoring of the Panoche-Ora Loma 115 kV line and the Wilson 115 kV static VAR compensator (SVC) project.

Five projects are in the San Diego Gas & Electric service area and one is in the Southern California Edison service area. There are no projects planned in the Valley Electric Association service area in this planning cycle.

None of the transmission projects address the 2020 or 2030 renewables portfolio standards; however, Millar says there is a pressing need to better manage generation from renewable sources, which creates wider changes in operating conditions. Ultimately, this will require more voltage support across the system. The system operator is seeing "the impacts in real time" and needs to address these and other voltage-control issues, Millar said.

An upgrade to the Lugo-Victorville 500 kV line is needed, Millar and Berberich said, but Cal-ISO is coordinating with the Los Angeles Department of Water & Power on the project. A detailed cost-benefits analysis is needed because it is an interregional project, which pushes it into the 2016-2017 planning cycle. The needs of the Los Angeles Basin and San Diego areas specific to 230 kV loading in the region will also be addressed in that time frame.

Striving to meet the 50 percent RPS may require looking carefully at transmission needs. "As the system is changing in ways we hadn't historically anticipated," said Berberich, "we're going to have to be agile around re-evaluating the transmission system and what's really needed.

"There are lots of moving parts." *–L. D. P.*

[14.2] Cal-ISO Approves Changes to Commitment Cost-Bidding Process

The Cal-ISO Board of Governors on March 25 approved changes to the commitment cost-bidding process after weighing concerns that the proposal might hinder the use of preferred resources and did not adequately address concerns from demand-response providers.

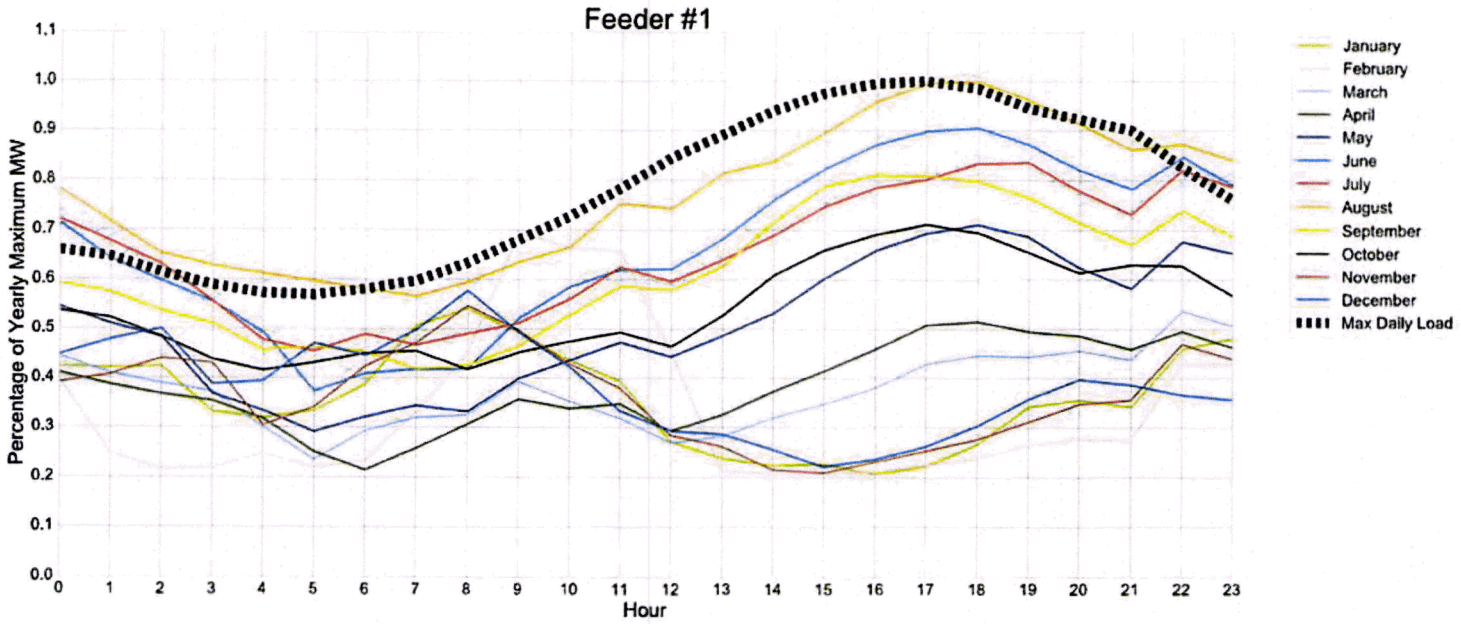
Under the changes, use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. The move will allow the ISO to eliminate the "registered cost" option for bidding commitment costs, under which a market participant can bid fixed costs for 30 days.

Cal-ISO now has roughly 35,000 MW of use-limited resources available. The goal is to commit these resources when they are of most value to the grid and at maximum profit for the generation owner.

The original language on commitment costs was altered to reflect comments made by CPUC Commissioner Mike Florio.

Florio's changes address concerns related to the use-limited status of preferred resources. This includes giving parties that might be affected—including investor-owned utilities, demand-response and energy-storage providers, and others—more time to better understand and manage the transition to the cost-bidding structure.

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures


Feeder #1
Percentage of Yearly Maximum MW
Hour
1.1
1.0
0.9
0.8
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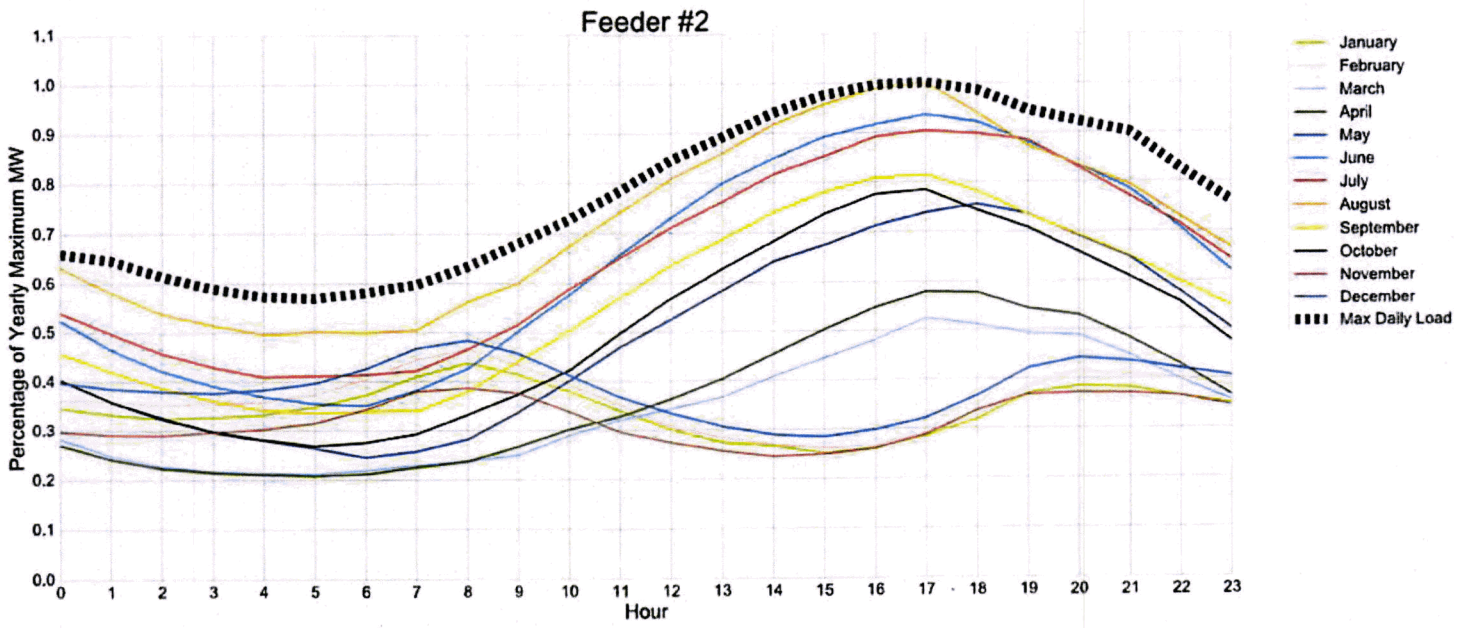
Max Daily Load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Percentage of Yearly Maximum MW
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0.9
0.8
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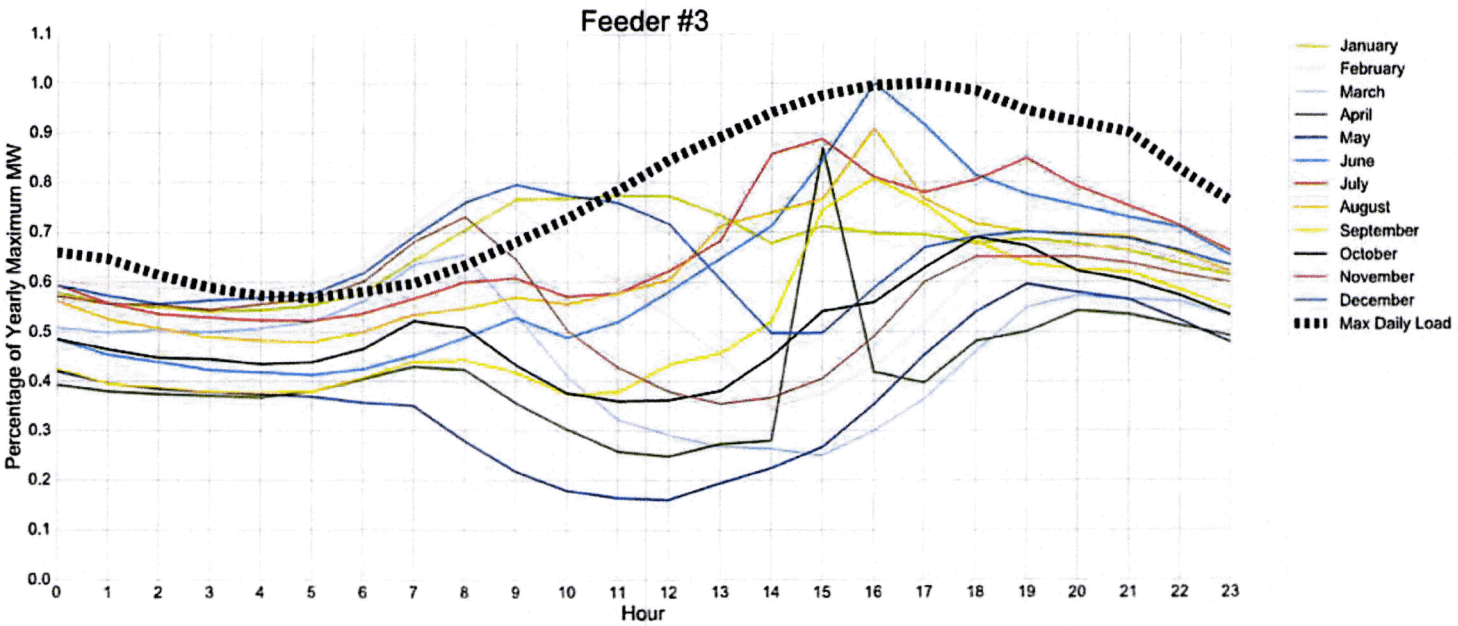
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Percentage of Yearly Maximum MW
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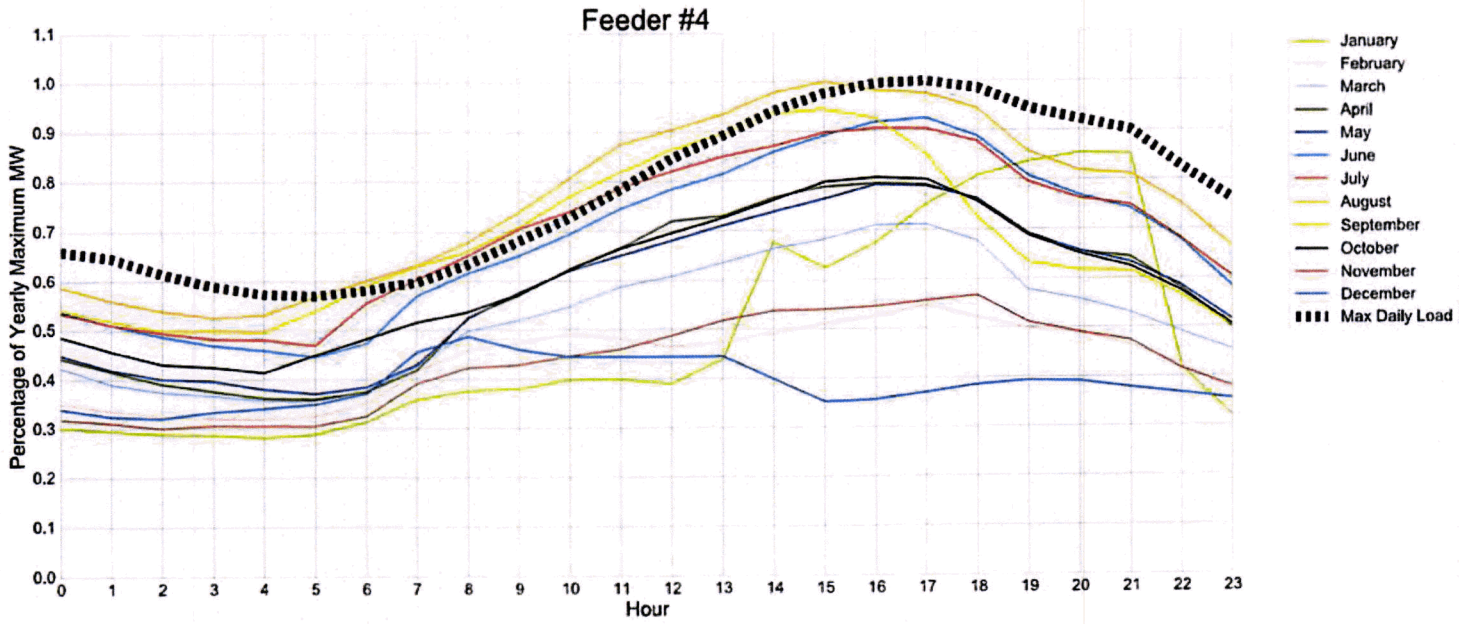
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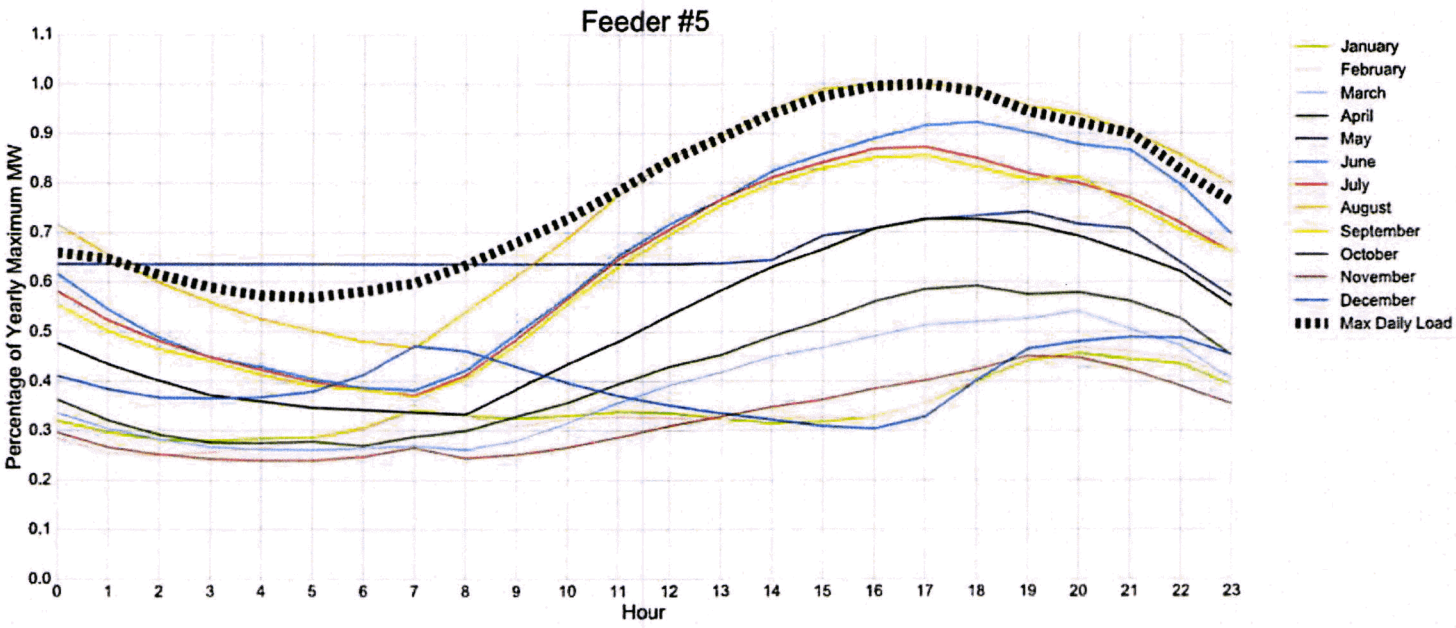
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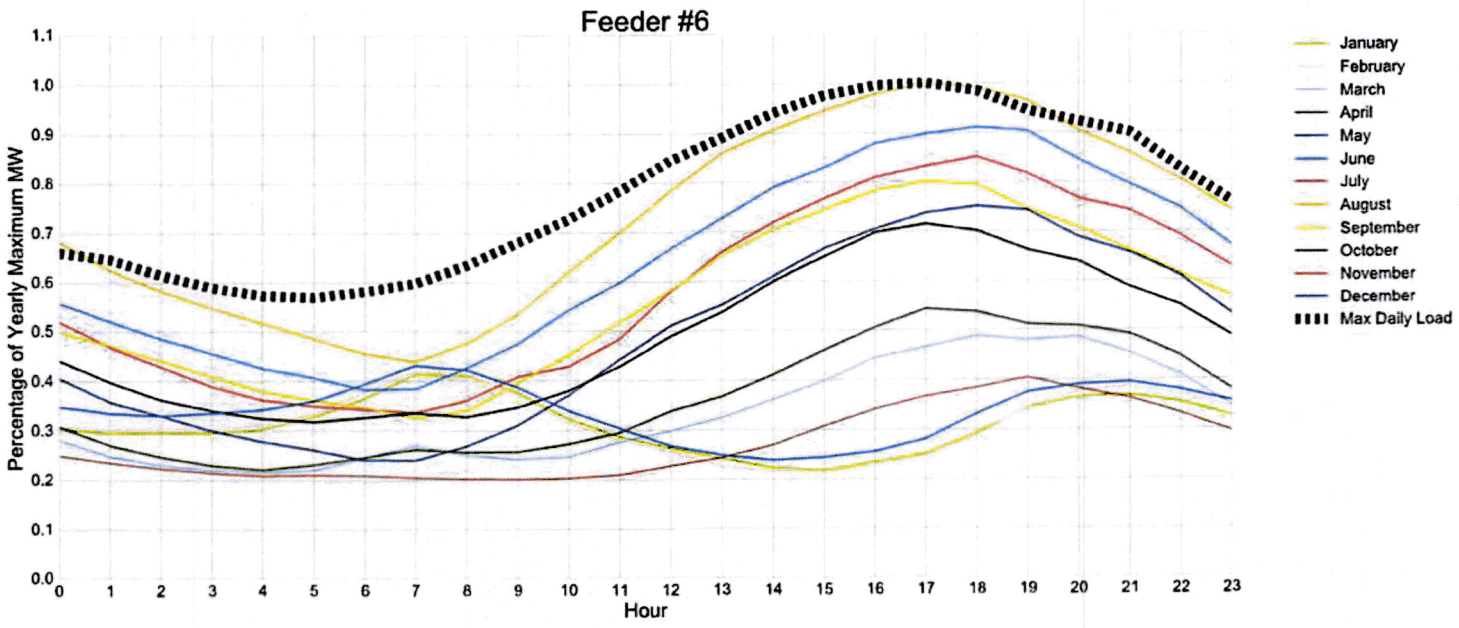
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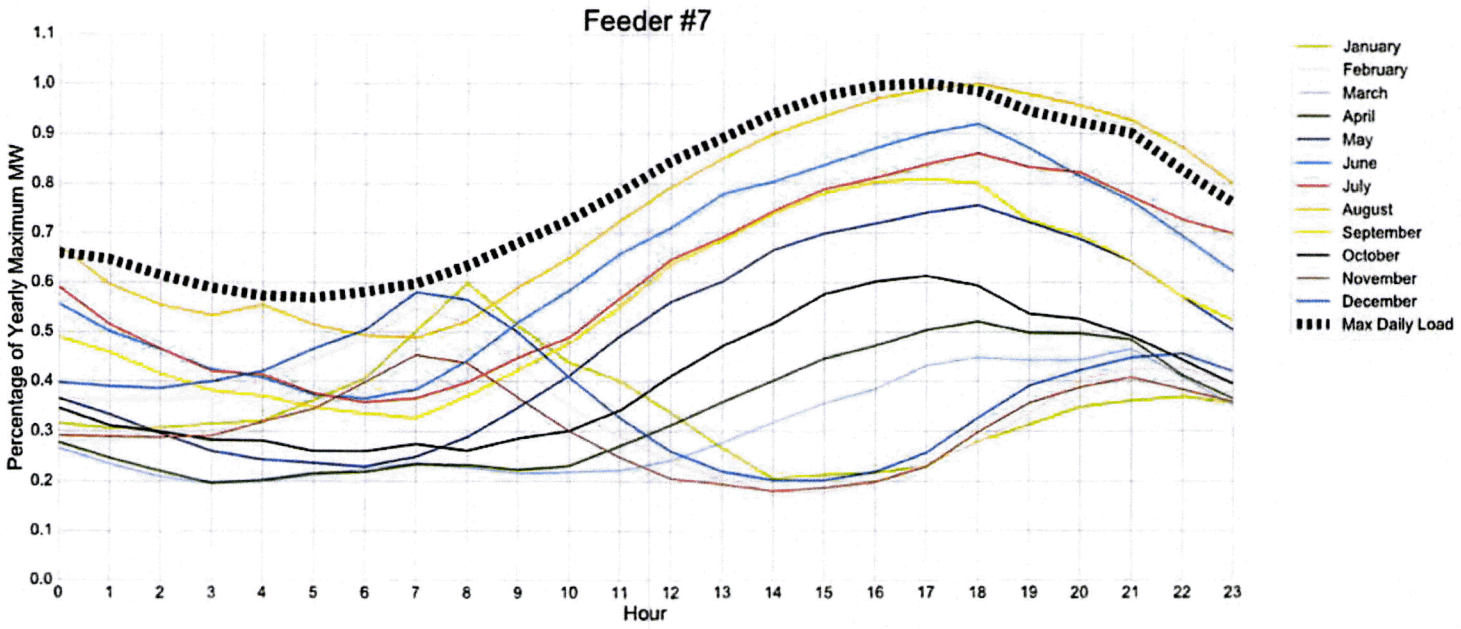
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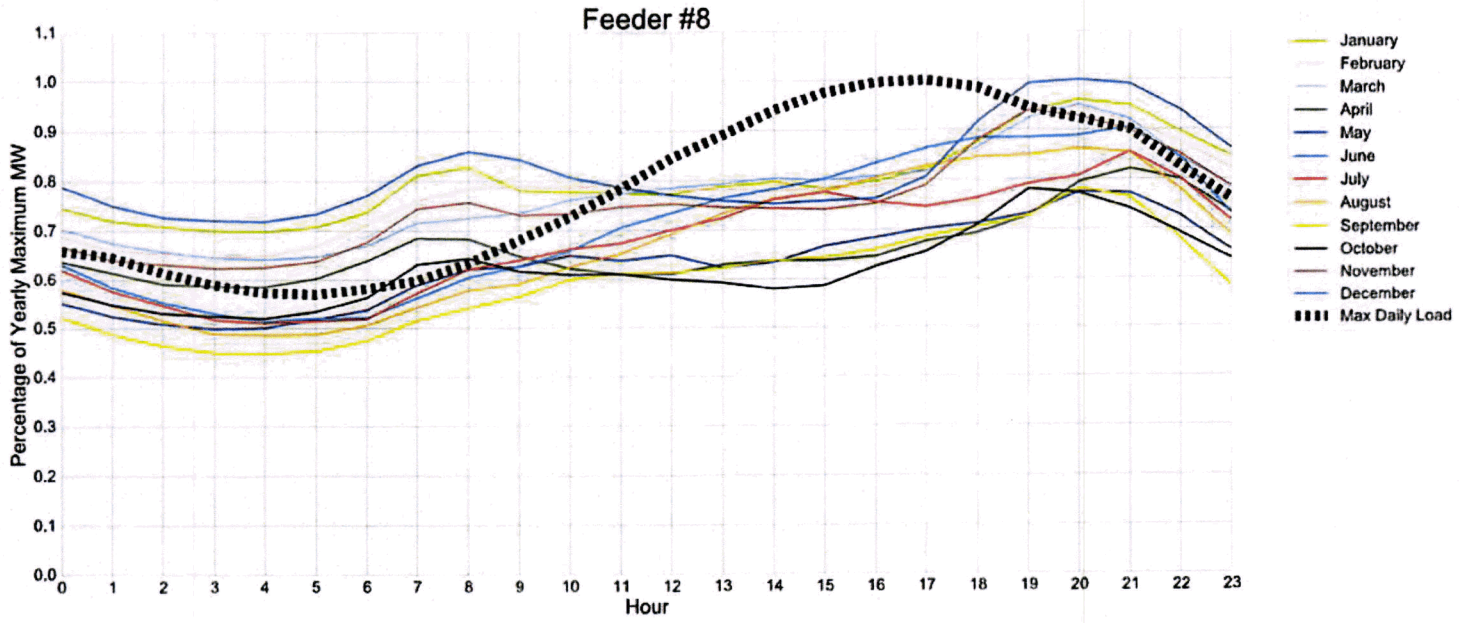
Max Daily Load


Feeder #8
Percentage of Yearly Maximum MW
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Max Daily Load

Exhibit WAM-9: Excerpt from PG&E 2014 General Rate Case Phase II Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design, Application 13-04-012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs. Revenue Allocation. and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18. 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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Dated: July 16. 2014

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION ISSUES IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in the proceeding captioned above. The details of this Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement are set forth herein.

This MC/RA Settlement Agreement is a direct result of Administrative Law Judge (ALJ) Douglas Long and Assigned Commissioner Michael Peevey's encouragement to the active parties to meet and seek a workable compromise. The active parties hold differing views on numerous aspects of PG&E's initial marginal cost and revenue allocation proposals in Phase II of this General Rate Case (GRC) proceeding. However the Parties bargained earnestly and in good faith to seek a compromise and to develop this MC/RA Settlement Agreement, which is the product of arms-length negotiations among the Settling Parties on a number of disputed issues. These negotiations considered the interests of all of the active parties on marginal cost and revenue allocation issues, and the MC/RA Settlement Agreement addresses each of these interests in a fair and balanced manner.

The Settling Parties developed this MC/RA Settlement Agreement by mutually accepting concessions and trade-offs among themselves. Thus, the various elements and sections of this

MC/RA Settlement Agreement are intimately interrelated, and should not be altered, as the Settling Parties intend that this Settlement Agreement be treated as a package solution that strives to balance and align the interests of each party. Accordingly, the Settling Parties respectfully request that the Commission promptly approve the MC/RA Settlement Agreement without modification. Any material change to the MC/RA Settlement Agreement shall render it null and void, unless all of the Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows[1/]:

- Agricultural Energy Consumers Association (AECA);
- California City-County Street Light Association (CAL-SLA);
- California Farm Bureau Federation (CFBF);
- California Large Energy Consumers Association (CLECA);
- California League of Food Processors (CLFP);
- California Manufacturers & Technology Association (CMTA);
- Direct Access Customer Coalition (DACC);
- Energy Producers and Users Coalition (EPUC);
- Energy Users Forum (EUF);
- Federal Executive Agencies (FEA);
- Office of Ratepayer Advocates (ORA);
- Pacific Gas and Electric Company (PG&E);
- Small Business Utility Advocates (SBUA);
- The Utility Reform Network (TURN); and
- Western Manufactured Housing Communities Association (WMA).

1/ Although the following parties have not joined the MC/RA Settlement Agreement, they have, nonetheless, affirmatively indicated that they do not oppose the MC/RA Settlement Agreement as presented herein: City and County of San Francisco (CCSF), Marin Clean Energy (MCE), Solar Energy Industries Association (SEIA), California Solar Energy Industries Association (CALSEIA), and the Modesto and Merced Irrigation Districts (MMID).

III. SETTLEMENT CONDITIONS

This MC/RA Settlement Agreement resolves the issues raised by the Settling Parties in A.13-04-012 (Phase II), on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This MC/RA Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This MC/RA Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the MC/RA Settlement Agreement only to arrive at the agreement embodied herein. Nothing contained in the MC/RA Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This MC/RA Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.
4. The Settling Parties agree that this MC/RA Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.
5. The Settling Parties agree that the language in all provisions of this MC/RA Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that this MC/RA Settlement Agreement addresses all marginal cost and revenue allocation issues.
7. This MC/RA Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this MC/RA Settlement Agreement and shall actively support its prompt approval. Active support shall include

written and/or oral testimony (if testimony is required), briefing (if briefing is required), comments and reply comments on the proposed decision,[2/] advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

9. The Settling Parties intend the MC/RA Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MC/RA Settlement Agreement, the Settling Parties reserve their rights under Rule 12 of the CPUC's Rules of Practice and Procedure, and the MC/RA Settlement Agreement should not be admitted into evidence in this or any other proceeding.

IV. OVERALL PROCEDURAL HISTORY

On January 24, 2013, PG&E requested, and the CPUC approved, a two-month extension of time to file its Application in Phase II of the 2014 GRC. The extension revised the filing date from February 13, 2013 (as required under the CPUC's Rate Case Plan) to April 18, 2013.

On April 18, 2013, PG&E filed A.13-04-012, related to electric marginal costs, revenue allocation, and rate design. As set forth at page 1 of that application, PG&E's marginal cost, revenue allocation and rate design proposals were intended:

> [T]o make progress in moving electric rates closer to cost of service, in order to send more economically efficient price signals and promote more equitable treatment among all customers. At the same time, PG&E balances other objectives including customer acceptance, rate stability, and simplifying electric rates to make them easier for customers to understand.

The application was protested on May 20, 2013, by ORA, TURN, Greenlining/CforAT, AECA/CFBF, and MCE.

A prehearing conference was held on June 3, 2013, before ALJ Long. The scope of issues and procedural schedule were set forth in the Assigned Commissioner's Scoping Memorandum and Ruling dated July 12, 2013 (Scoping Memo). Per the Scoping Memo, PG&E's updated testimony required under the CPUC's Rate Case Plan was due on August 2,

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2/ Any oral and written testimony that the CPUC might require may be prepared and submitted jointly among parties with similar interests.

2013. On July 26, 2013, at PG&E's request, ALJ Long granted a two-week extension of that filing date. On August 16, 2013, PG&E updated its showing on marginal costs, revenue allocation, and rate design.

In a ruling issued October 18, 2013, ALJ Long modified the scope of A.13-04-012 to suspend work on residential rate design in anticipation that residential rate design issues would be considered in the Residential Rate Reform Order Instituting Rulemaking (RROIR, R.12-06-013), in which the CPUC would be examining and modifying residential rate structures in accordance with Assembly Bill (AB) 327.[3/] On Wednesday, November 6, 2013, ALJ Long clarified that electric master meter discounts and gas baseline quantities would not be suspended but rather would remain within the scope of GRC Phase II. On November 8, 2013, PG&E issued a notice of availability of revenue allocation and rate design models that were consistent with the suspension and deferral of residential electric rate design.

ORA served its prepared testimony on November 15, 2013, on marginal cost, revenue allocation, non-residential rate design, and residential electric master meter discounts. On December 13, 2013, fifteen intervenors (AECA, CAL-SLA, CFBF, CLECA/CMTA, CCSF, DACC, EUF, EPUC, FEA, MMID, MCE, SBUA, SEIA, TURN, and WMA) served their prepared testimony. On January 17, 2014, ALJ Long issued a ruling granting the parties' joint request for a continuance in the original schedule for Phase II of PG&E's 2014 GRC, in recognition of the parties' ongoing efforts to seek settlement, as discussed below.

V. SETTLEMENT HISTORY

Pursuant to Rule 12 of the CPUC's Rules of Practice and Procedure, on January 9, 2014, PG&E served on all parties a notice of a settlement conference to be held January 17, 2014. Immediately after that settlement conference, PG&E on behalf of the parties, emailed a request to the ALJ, and ALJ Long promptly issued an email ruling on January 17, 2014, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, with settlement status reports to be filed on February 14 and March 12, 2014. On March 20, and

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3/ The CPUC, accordingly, re-categorized the RROIR as a ratesetting proceeding in January 2014.

on May 21, 2014, ALJ Long granted further continuances in the schedule to allow the parties time for additional work on settlement of issues in this proceeding.

On March 13, 2014, the parties participating in settlement discussions reached an agreement in principle on the terms of this MC/RA Settlement Agreement. On March 20, 2014, PG&E orally notified ALJ Long that the active parties to the proceeding had reached settlement in principle regarding marginal cost and revenue allocation-related issues. As part of the joint settlement status reports filed in this proceeding, PG&E informed ALJ Long that the parties were continuing separate settlement discussions among sub-groups of parties interested in the remaining GRC Phase II issues, as discussed in Section VI below.

VI. SETTLEMENT TERMS

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this MC/RA Settlement Agreement. The revenue allocation amounts, percentages, and procedures agreed to in this MC/RA Settlement Agreement are reasonable and based on the record in this proceeding.

No later than July 25, 2014, PG&E and ORA will jointly serve a comparison exhibit showing the impact of the MC/RA Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a).

The Settling Parties agree that all testimony served prior to the date of this MC/RA Settlement Agreement that addresses the issues resolved by this MC/RA Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree to try to reach agreement on additional issues in A.13-04-012 including the remaining residential rate design issues and the non-residential rate design issues that are not resolved by this MC/RA Settlement Agreement.[4/] To the extent all of those rate design issues are not ultimately settled, the Settling Parties agree to pursue litigation in this

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4/ PG&E is still conducting separate settlement discussions in the areas of: (1) small and medium commercial rate design, (2) large commercial and industrial rate design (including standby), (3) agricultural rate design, (4) streetlight rate design, (5) rates for Schedule E-Credit, and (6) limited residential rate design issues not being considered in the RROIR. If and as settlements are reached on such rate design issues, they will be submitted as supplements to this Settlement, as was done in PG&E's 2011 GRC Phase II proceeding.

proceeding on those rate design issues only, provided those issues do not affect the outcome of issues agreed upon in this MC/RA Settlement Agreement.

The Settling Parties agree that Agricultural party proposals relating to aggregation of accounts and Public Utilities Code § 744(c)'s potential requirements, as well as adjustments for the transfer of customers from flat rates to Time-Of-Use (TOU) rates, will be removed from revenue allocation discussions in this proceeding. These items will be included among the other issues to be considered in the Agricultural rate design settlement discussions, and shall be resolved in such a way as not to have revenue allocation implications when combined with other agricultural rate design changes. Specifically, any revenue loss from the transfer of customers to TOU rates or from any load aggregation proposals that may be adopted will not result in inter-class revenue transfers. The details of how this will be accomplished will be addressed with the Agricultural rate design in this proceeding.

VII. MARGINAL COSTS SETTLEMENT

This MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below. The Settling Parties agree that this MC/RA Settlement Agreement addresses all necessary marginal cost issues including the specific marginal costs to be used solely for the purpose of establishing costs where needed for customer specific contract analysis including as required by Schedule E-31 and for analysis of contribution to margin for customers taking service under Schedule EDR. The marginal costs to be used for these analyses are provided in Appendix A to this MC/RA Settlement Agreement. Nothing in this MC/RA Settlement Agreement shall preclude any Settling Party from advocating for its preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this or other rate design proceedings.

If the Commission were to adopt new marginal costs/methodologies, the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the agreed revenue allocation, as set forth in this MC/RA Settlement Agreement.

VIII. REVENUE ALLOCATION SETTLEMENT

1. Revenue Allocation Principles for the Phase II Allocation

The Settling Parties agree that electric revenue should be allocated as a result of A.13-04-012 on an overall revenue-neutral basis to preserve then-required total authorized revenue. The Settling Parties agree to the Phase II revenue allocation to be implemented as a result of this proceeding as set forth in the following Table 1. Table 1 shows the electric revenue based on present rates used to prepare this Settlement, the electric revenue that results from the Settlement, and the percentage change for both bundled and Direct Access/Community Choice Aggregation (DA/CCA) customers. The Settling Parties agree that upon implementation PG&E will target the average percentage change for every customer group shown in Table 1, but the actual results may vary based on rate and sales changes that will occur before this MC/RA Settlement Agreement is implemented. The Settling Parties agree as follows:

a. The revenue allocation percentages shown in Table 1 establish the basis for the Phase II allocation resulting from this proceeding.

b. The parties agree that rate design changes that may be considered in future settlements in this proceeding will be designed so as not to result in projected revenue shortfalls from any class. This provision includes, but is not limited to, agricultural account aggregation and any additional transition of agricultural customers from flat to TOU rates.

c. There is no agreement on the specific marginal cost values for purposes of revenue allocation.

d. There is no change to the allocation of Nuclear Decommissioning, the Department of Water Resources (DWR) bond charge, the Energy Costs Recovery Amount, the New System Generation Charge (NSGC), Greenhouse Gas Allowance Return, the Competition Transition Charge (CTC), or, for DA/CCA customers, the Power Charge Indifference Adjustment (PCIA).

e. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

f. There is no change to the allocation of Public Purpose Program (PPP) rates except due to the recalculation of the cost of the CARE discount. PPP rates will be developed as the sum of public purpose program components:

1. The cost of the CARE discount will be determined based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the California Solar Initiative cost, and the DWR bond charge. This cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This requires an iterative determination of the CARE surcharge in PG&E's revenue allocation and rate design model.

2. There is no change to the methodology for setting rates for the remaining public purpose program components for the Phase II allocation.

g. After the allocations of all the revenues described above have been determined, PG&E will seek to create the following bundled and DA/CCA percentage changes agreed to in this proceeding by implementing the following three steps:

Step 1: For each customer class, set the bundled increase not to exceed 0.95 percent and the bundled decrease not to be less than -0.78 percent. For each customer class, set the DA/CCA increase not to exceed 2.60 percent and the DA/CCA decrease not to be less than -1.40 percent. In addition, the bundled residential increase will be limited to 0.50 percent. The revenue allocation mitigation methodology shall be consistent with that set forth in Exhibit PG&E-4, p. 2-12, line 11 through p. 2-13, line 2, modified to substitute the agreed limits on increases and decreases set forth above.

Step 2: At the time this agreement was signed, PG&E's revenue allocation and rate design model showed that the above limits on increases and decreases would result in full collection of PG&E's revenue based on the assumptions used in the model at that time. However, if at the time

this Settlement is implemented, the use of these agreed limitations results in revenue adjustments that do not add to zero (i.e., do not collect the then-required revenue), PG&E shall allow the DA/CCA class level revenue for E-19 to adjust so that any revenue changes necessary to collect the then-required revenue are taken up by that class, provided however, the change to the DA/CCA class level revenue to E-19 is as small as reasonably possible and does not exceed the cap or floor. Similarly, for bundled customers, any necessary revenue changes necessary to collect the then-required revenue would be taken up by the residential class whose change should also be as small as reasonably possible and not exceed the cap or floor. Should these adjustments not be sufficient to collect the then-required revenue, further adjustments will be made to the revenue for all classes as necessary to collect the then-required revenue and will be as small as reasonably possible.[5/]

Step 3: As a final step, once the model is able to fully collect the then-required revenue, if the solution results in a rate increase to the bundled residential class of more than 0.50 percent, all bundled percentage changes will be increased by an identical amount until this increase is equal to the amount that the residential increase is over 0.50 percent. For example, a bundled increase not to exceed 0.98 percent for the Streetlighting and Agricultural classes, a bundled decrease not to be less than -0.75 percent for the Small, Medium, E-19, E-20 and Standby customer classes, and a bundled increase of 0.53 percent for the Residential class would result in an increase of 0.03 percent above the agreed upon level for all classes.

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5/ Step 2 would not be required if the then-required revenue is fully collected in Step 1.

Table 1
Pacific Gas and Electric Company Phase II
Settlement Revenue Allocation Results

Bundled Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$5,309,098,010	$5,335,623,998	0.50%
Small Light & Power	$1,613,868,527	$1,601,320,699	-0.78%
Medium Light & Power	$1,239,640,531	$1,230,002,326	-0.78%
E-19	$1,816,293,284	$1,802,171,604	-0.78%
Streetlight	$69,901,669	$70,565,734	0.95%
Standby	$57,392,554	$56,946,327	-0.78%
Agricultural	$864,359,596	$872,571,013	0.95%
E-20T	$368,809,086	$365,941,596	-0.78%
E-20P	$577,978,010	$573,484,231	-0.78%
E-20S	$231,273,602	$229,478,926	-0.78%
Total Bundled	$12,148,614,871	$12,138,106,453	-0.09%

DA/CCA Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$85,603,947	$84,405,491	-1.40%
Small Light & Power	$32,281,647	$31,829,704	-1.40%
Medium Light & Power	$53,964,217	$55,367,287	2.60%
E-19	$223,887,070	$228,173,886	1.91%
Streetlight	$887,638	$910,716	2.60%
Standby	$1,707,723	$1,683,818	-1.40%
Agricultural	$3,111,140	$3,192,029	2.60%
E-20T	$50,464,260	$51,645,799	2.34%
E-20P	$121,563,706	$124,721,565	2.60%
E-20S	$44,386,361	$45,529,739	2.58%
FPP T[2]	$3,336,837	$3,554,126	6.51%
FPP P[2]	$196,285	$204,185	4.02%
FPP S[2]	$1,727,634	$1,783,220	3.22%
Total DA/CCA	$623,118,465	$633,001,568	1.59%

(1) Present rate revenue is based on rates effective May 1, 2013.

(2) FPP revenue is combined with E-20, by voltage, for application of caps and floors.

2. Timing of the Phase II Rate Change

If the rate change pursuant to this MC/RA Settlement Agreement occurs in 2014, it shall

Exhibit WAM-10: Excerpt from
California Public Utilities Commission, Decision15-08-005

ALJ/DUG/SCR/ek4 **Date of Issuance 8/18/2015**

Decision 15-08-005 August 13, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M).	Application 13-04-012 (Filed April 18, 2013)

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision adopts eight separate settlements as proposed by the settling parties and resolves the remaining outstanding issues based on the merits of the litigated positions. This completes the current review of Pacific Gas and Electric Company's (PG&E) electric marginal costs, revenue allocation, and rate design. Adoption of these new rates will reallocate the existing authorized revenue requirement amongst the various customer classes and within those customer classes. One settlement was partially contested and this decision resolves those contested issues primarily in accordance with the proposed settlements.

Because this proceeding deals with only rate design related questions and not operating or capital costs, or how PG&E operates its electric system, there are no changes to PG&E's overall authorized revenue requirement, although individual customer's bills may change as a result of changes in rate design. Also, there is no impact on employee, customer, or public safety, again because this decision does not change PG&E's revenue requirement or have any direct impact on electric operations.

This proceeding is closed.

1. Procedural History

The proceeding has a complex history, as parties sought and were granted numerous extensions of time to complete settlement negotiations with various sub-groups of interested parties which resulted in eight separate settlements covering all but a few issues that were litigated. All settlement rules were followed and all parties had notice and opportunity to participate. The

find that they contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds for its adoption; that the settlement was limited to the issues in this proceeding; and that the settlement included a comparison indicating the impact of the settlement in relation to the utility's application and contested issues raised by the interested parties in prepared testimony, or that would have been contested in a hearing. These two findings that the settlement complies with Rule 12.1(a), allow us to conclude, pursuant to Rule 12.1(d), that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Based upon our review of the settlement documents we find, pursuant to Rule 12.5, that the proposed settlements would not bind or otherwise impose a precedent in this or any future proceeding. We specifically note, therefore, that neither PG&E nor any party to any of the settlements may presume in any subsequent applications that the Commission would deem the outcome adopted herein to be presumed reasonable and it must, therefore, fully justify every request and ratemaking proposal without reference to, or reliance on, the adoption of these settlements.

7. Summary of Settlements

A copy of all eight of the Settlement Agreements, fully executed by all interested parties, are available at the links below following each settlement. The final language of the settlement controls the terms and conditions of the adopted rates except as specifically modified herein. The proposed settlements are as follows:

1. Settlement Agreement on Marginal Cost and Revenue Allocation Issues, filed July 16, 2014;

http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=99753189;

2. Residential Rate Design Supplemental Settlement Agreement, filed July 24, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=101125976;

3. Large Light and Power Rate Design Settlement Agreement, filed July 25, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=102226995;

4. Streetlight Rate Design Supplemental Settlement Agreement, filed August 29, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=103390568

5. Amended E-Credit Rate Design Supplemental Agreement, filed March 30, 2015;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=151726093;

6. Medium Commercial Rate Design Settlement Agreement, filed September 5, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=105647677;

7. Small Commercial Rate Design Settlement Agreement, filed September, 5, 2014; and

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=107147806

8. Agricultural Rate Design Settlement Agreement, filed December 2, 2014.

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=143515264.

Exhibit WAM-11: Excerpt from
California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

Pacific Gas and Electric Company
2014 General Rate Case Phase II, A.13-04-012

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION
Appendix A

Marginal Generation Energy Costs:

Table 1 - 2014 Marginal Generation Energy Costs by Time of Use (TOU) Rate Period and Voltage Level (¢/kWh)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	5.613	5.718	6.001
2	Summer Partial-Peak	4.791	4.881	5.123
3	Summer Off-Peak	3.654	3.722	3.907
4	Winter Partial-Peak	4.856	4.948	5.192
5	Winter Off-Peak	3.968	4.043	4.243
6	Annual Average	4.266	N.A.	N.A.

Marginal Transmission and Distribution Costs:

Table 2: 2014 Marginal Transmission Capacity Cost ($/kW-Yr)

Line No.	Transmission Capacity
1	34.86

Table 3: 2014 Distribution Marginal Customer Access Costs ($/Customer-Yr)

Line No.	Class	Marginal Customer Access Cost
1	Residential	73.72
2	Agricultural A	321.96
3	Agricultural B	1,457.43
4	Small L & P	323.37
5	A10 Medium L & P Secondary	638.43
6	A10 Medium L & P Primary	1,917.29
7	E19 Secondary	748.05
8	E19 Primary	6,288.92
9	E19 Transmission	6,650.02
10	E20 Secondary	5,559.77
11	E20 Primary	6,688.18
12	E20 Transmission	6,659.54
13	Streetlights	83.05
14	Traffic Control	105.91

Table 4: 2014 Marginal Distribution Capacity Costs by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Yr)	New Business on Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	95.45	12.31	4.00
2	De Anza	112.71	22.30	2.45
3	Diablo	52.57	20.78	4.01
4	East Bay	60.29	18.87	1.44
5	Fresno	30.31	8.05	1.61
6	Kern	31.43	7.95	1.97
7	Los Padres	40.87	9.75	2.03
8	Mission	19.87	9.90	1.81
9	North Bay	17.74	12.66	2.13
10	North Coast	42.22	12.65	3.13
11	North Valley	36.06	16.22	3.60
12	Peninsula	38.62	10.46	2.98
13	Sacramento	37.65	13.07	2.21
14	San Francisco	18.33	6.24	1.28
15	San Jose	38.50	12.18	2.79
16	Sierra	29.68	10.15	3.21
17	Stockton	38.26	8.85	2.30
18	Yosemite	45.78	17.54	2.94
19	System	37.33	11.26	2.33

Table 5: 2014 Marginal Distribution Capacity Costs by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	Carmel Valley 12kV	0.00	31.07	31.07	12.31	4.00
2	Central Coast	Gonzales	0.00	31.07	31.07	12.31	4.00
3	Central Coast	Hollister	16.07	31.07	47.14	12.31	4.00
4	Central Coast	King City	129.50	31.07	160.57	12.31	4.00
5	Central Coast	Monterey 21kV	0.00	31.07	31.07	12.31	4.00
6	Central Coast	Mty_4kV (Monterey Bk#1F	0.00	31.07	31.07	12.31	4.00
7	Central Coast	Oilfields	0.00	31.07	31.07	12.31	4.00
8	Central Coast	Prunedale	0.00	31.07	31.07	12.31	4.00
9	Central Coast	Pt Moretti	0.00	31.07	31.07	12.31	4.00
10	Central Coast	Salinas (4/12 kV)	33.73	31.07	64.80	12.31	4.00
11	Central Coast	Santa Cruz Area	0.00	31.07	31.07	12.31	4.00
12	Central Coast	Seaside 4kV	0.00	31.07	31.07	12.31	4.00
13	Central Coast	Seaside-Marina 12kV	60.75	31.07	91.82	12.31	4.00
14	Central Coast	Soledad	0.00	31.07	31.07	12.31	4.00
15	Central Coast	Watsonville (12/21kV)	277.75	31.07	308.82	12.31	4.00
16	Central Coast	Watsonville (4kV)	0.00	31.07	31.07	12.31	4.00
17	De Anza	Cupertino	0.00	15.15	15.15	22.30	2.45
18	De Anza	Los Altos (12 kV)	130.97	15.15	146.12	22.30	2.45
19	De Anza	Los Altos (4kV)	0.00	15.15	15.15	22.30	2.45
20	De Anza	Los Gatos	101.47	15.15	116.62	22.30	2.45
21	De Anza	Mountain View	70.62	15.15	85.77	22.30	2.45
22	De Anza	Sunnyvale	108.09	15.15	123.24	22.30	2.45
23	Diablo	Alhambra	0.00	28.54	28.54	20.78	4.01
24	Diablo	Brentwood	0.00	28.54	28.54	20.78	4.01
25	Diablo	Clayton / Willow Pass	0.00	28.54	28.54	20.78	4.01
26	Diablo	Concord	22.24	28.54	50.77	20.78	4.01
27	Diablo	Delta (Split Into Bw And Pitts)	0.00	28.54	28.54	20.78	4.01
28	Diablo	Pittsburg	18.00	28.54	46.54	20.78	4.01
29	Diablo	Walnut Creek 12 kV	24.79	28.54	53.32	20.78	4.01
30	Diablo	Walnut Creek 21 kV	30.60	28.54	59.14	20.78	4.01
31	East Bay	C-D-L	128.09	8.29	136.39	18.87	1.44
32	East Bay	Edes-J	0.00	8.29	8.29	18.87	1.44
33	East Bay	K-X	0.00	8.29	8.29	18.87	1.44
34	East Bay	North	0.00	8.29	8.29	18.87	1.44
35	East Bay	South	60.14	8.29	68.44	18.87	1.44

EXHIBIT
TASC 30
ADMITTED

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023** **THE ALLIANCE FOR SOLAR CHOICE'S (TASC) NOTICE OF FILING ERRATA OF DIRECT TESTIMONIES OF R. THOMAS BEACH AND WILLIAM A. MONSEN**

The Alliance for Solar Choice ("TASC") hereby provides this Notice of Filing Errata of the Direct Testimonies of R. Thomas Beach and William A. Monsen in the above referenced matter. Attached you will find corrections to the aforementioned testimonies.

RESPECTFULLY SUBMITTED this 5th day of May, 2016.

/s/ Court S. Rich
Court S. Rich
Attorney for The Alliance for Solar Choice

Original and 13 copies filed on this 5th day of May, 2016 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served the foregoing documents on all parties of record in this proceeding by sending a copy via electronic or regular mail to:

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EXHIBIT A

Errata corrections to

Direct Testimony of R. Thomas Beach

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
CHAIRMAN

BOB STUMP
COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

ERRATA CORRECTIONS TO DIRECT TESTIMONY OF R. THOMAS BEACH

Errata to Exhibit 2 to Direct Testimony of R. Thomas Beach on behalf of TASC

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

Page	Original	Corrected
8	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.3 cents per kWh, in 2014 dollars.	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.2 cents per kWh, in 2016 dollars.
14	The result is a solar DG value for transmission capacity equal to about $14 per kW-year for south-facing systems (i.e. $37 per kW-year x 39% contribution to peak) and $19 per kW-year for west-facing.	The result is a solar DG value for transmission capacity equal to about $16 per kW-year for south-facing systems (i.e. $43 per kW-year x 36% contribution to peak) and $23 per kW-year for west-facing.
14	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $8 per MWh (0.8 cents per kWh) for south-facing systems and $13 per MWh (1.3 cents per kWh) for west-facing systems.	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $9 per MWh (0.9 cents per kWh) for south-facing systems and $16 per MWh (1.6 cents per kWh) for west-facing systems.

EXHIBIT B

Errata corrections to
Direct Testimony of William A. Monsen

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

ERRATA CORRECTIONS TO DIRECT TESTIMONY OF WILLIAM A. MONSEN

The attached includes a complete set of exhibits to Mr. Monsen's testimony that fully incorporate the specific corrections identified below:

- Exhibit WAM-2, p. 2 (APS's Response to TASC's Data Request 1.15): Replaces original page with APS's Supplemental Response to Data Request 1.15 which should have been attached originally.

- Exhibit WAM-2, pp. 7-8 (APS's Response to TASC's Data Request 2.1): This data request response was inadvertently omitted from Mr. Monsen's testimony and is attached hereto.

- Exhibit WAM-3, p 2 (APS Response to Vote Solar' Data Request 1.1) This data request response was inadvertently omitted from Mr. Monsen's testimony and is attached hereto.

- Exhibit WAM-9 was replaced in its entirety by the new Exhibit WAM-9 (PG&E 2014 GRC Phase II Prepared Testimony, p. 2-8). The Settlement Document was inadvertently included instead of the Testimony attached hereto.

Table of Exhibits

Exhibit WAM-1: Resume of William A. Monsen

Exhibit WAM-2: APS Responses to TASC Data Requests

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

Exhibit WAM-4: Excerpt from "Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015

Exhibit WAM-5: Excerpt from "Energy Star: Program Requirements for Programmable Thermostats,"

Exhibit WAM-6: Excerpt from Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Exhibit WAM-7: California Energy Markets, Issue No. 1379, April 1, 2016

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures

Exhibit WAM-9: Excerpt from PG&E 2014 General Rate Case Phase II Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design, Application 13-04-012

Exhibit WAM-10: Excerpt from California Public Utilities Commission, Decision15-08-005

Exhibit WAM-11: Excerpt from California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

Exhibit WAM-1: Resume of William A. Monsen

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.

William A. Monsen

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (California PUC) Applications 90-08-066, 90-08-067, 90-09-001
   Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.

2. California PUC Application 90-10-003
   Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.

3. California Energy Commission Docket No. 93-ER-94
   Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.

4. California PUC Rulemaking 94-04-031 and Investigation 94-04-032
   Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.

5. Massachusetts Department of Telecommunications and Energy DTE 97-120
   Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.

6. California PUC Application 97-12-039
   Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.

7. California PUC Application 99-09-053
   Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.

8. California PUC Application 99-09-053
   Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.

9. California PUC Rulemaking 99-10-025
   Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. California PUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.

11. California PUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.

12. California PUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.

13. California PUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.

14. California PUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. California PUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.

16. California PUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.

17. Arizona Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.

18. California PUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.

19. California PUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.

20. California PUC Rulemaking 01-10-024
Direct testimony of William A. Monsen Regarding Long-Term Resource Planning Issues On Behalf of the City of San Diego. June 23, 2003.

21. California PUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.

22. California PUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation On Behalf of the Local Government Commission Coalition. April 15, 2004.

23. California PUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.

24. California PUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.

25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. October 18, 2004.

28. California PUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.

29. California PUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. California PUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.

31. California PUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.

32. California PUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.

33. California PUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.

34. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.

35. California PUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.

36. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.

37. Colorado PUC Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.

38. California PUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.

39. California PUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association Regarding Integrated Resource Planning. September 13, 2006.

41. California PUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company For Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.

42. Colorado PUC Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy Association. April 28, 2008.

43. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.

44. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.

45. California PUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of The California Demand Response Coalition Concerning Demand Response Cost-Effectiveness And Baseline Issues. November 24, 2008.

46. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation And Rate Design Issues In The San Diego Gas & Electric Company And Southern California Gas Company Biennial Cost Allocation Proceeding. December 23, 2008.

47. California PUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost Allocation And Rate Design. January 9, 2009.

48. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. January 27, 2009.

49. California PUC Application 08-11-014
Testimony of William A. Monsen on Behalf of The City of San Diego Concerning the Application of San Diego Gas & Electric Company tor Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.

51. Public Utilities Commission of the State of Colorado 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.

52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E
Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.

53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," September 15, 2010.

54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," November 2, 2010.

55. California PUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.

56. Public Service Company of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.

57. California PUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. July 16, 2012.

59. California PUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding. July 23, 2012.

60. California PUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. July 23, 2012.

61. California PUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.

62. California PUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. August 3, 2012.

63. California PUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates' Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. September 14, 2012.

65. Public Utilities Commission of the State of Colorado Docket No 11A-869E Supplemental Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. October 5, 2012.

66. Public Utilities Commission of the State Oregon Docket No UM 1182 Northwest and Intermountain Power Producers Coalition Direct Testimony of William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness Reply Testimony of William A. Monsen. January 14, 2013.

68. California PUC Rulemaking 12-03-014
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. September 30, 2013.

69. California PUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. October 14, 2013.

70. California PUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy Alliance Regarding the Proposed Merger of NV Energy, Inc. with Midamerican Energy Holdings Company. October 24, 2013.

71. California PUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission and Storage Rate Application. August 11, 2014.

72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August 25, 2014.

73. California PUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission & Storage Application. September 15, 2014.

74. California PUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning Residential Electric Rate Design Reform. September 15, 2014.

75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Phase1A of the 2014 Long-Term Procurement Planning Proceeding. September 24, 2014.

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.

79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.

80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.

81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.

82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen On Behalf of The Alliance for Solar Choice (TASC). October 27, 2015.

Exhibit WAM-2: APS Responses to TASC Data Requests

This Exhibit includes the following Data Responses: TASC DR 1.15, 4.1, and 4.4
(Note: Response to DR 1.15 includes feeder data that has not been included
here. It can be provided on request.

TASC'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 26, 2016

TASC 1.15: Please provide, in Excel format, hourly load data, for the most recent historical year for which data is available, for a representative sample of distribution feeders on the APS system.

Response: APS is gathering this information and will provide a response as soon as possible.

Supplemental Response: Attached as APS15804 (in native Excel format) please find hourly data for eight feeders on the APS system that are geographically representative of feeders with primarily residential load. Please note that the majority of feeders in the APS system are dynamic; that is, customer loads on feeders change due to a number of factors including technology adoption, customer growth, infill construction, mix of customer type and others. These feeders may not constitute a representative sample in the future.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 MARCH 14, 2016

TASC 4.1: Please provide hourly loads for all of APS's residential customers for 2014 and 2015 in Excel format. In addition, please provide hourly loads for the following subsets of residential customers:

a. Customers participating in APS's energy efficiency programs;

b. Customers participating in APS's demand response programs;

c. Customers located in the city limits of Phoenix;

d. Customers located in the Phoenix metropolitan area;

e. Customers with rooftop solar;

f. Customers that do not have central air conditioning;

g. Customers that have swimming pools;

h. Customers that have setback thermostats that control their air conditioners;

i. Customers that are dual fuel customers (as discussed on page 26 of Mr. Snook's testimony);

j. Customers living in apartments (as discussed on page 25 of Mr. Snook's testimony);

k. Customers that are "empty nesters" (as discussed on page 25-26 of Mr. Snook's testimony).

For each set of hourly loads, please indicate the average number of customers included in each set.

Response: Hourly loads for each of APS's 1.1 million residential customers would consist of over 9.5 million data points annually, and is too voluminous to provide. However, APS is providing as APS15876 the total hourly load for 2014 for customers on each residential rate APS offers. These loads are disaggregated by each load type used by APS in the 2014 Cost of Service Study as discussed in APS Witness Snook's direct testimony. APS15876 also provides customer counts for each of the load types. Additionally, please see APS15871, provided in the Company's response to TASC Question 3.2, for average hourly loads for dual fuel, winter visitor, and apartment customers for 2014 as discussed in Mr. Snook's testimony. If average per customer loads are desired, please divide the total hourly loads by the customer count provided.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.1 Supplemental Response:

a - b. APS does not possess hourly load data for energy efficiency and demand response participants as the Company's customer information system (CIS) does not track these customers.

c – d. APS objects to this request as unduly burdensome and seeking irrelevant information that is not likely to lead to the discovery of admissible evidence. Further, no documents exist with this information. Although APS's customer information system does contain the zip codes in which customers live, any document showing this information would have to be created through targeted queries to its database, compilation of data, and organization and labeling of data into an understandable Excel format.

e. Please see APS15876 for total hourly loads and customer counts of customers with rooftop solar, from which an average hourly load can be easily derived.

f – h. APS does not possess hourly load data for central air conditioning, swimming pools, or setback thermostat customers as the Company's CIS does not track these customers.

i – j. Please see APS15878, provided in the Company's second supplemental response to TASC Question 3.2, for average hourly loads for dual fuel customers and apartment dwellers.

k. APS does not possess hourly load data for "empty nesters", as CIS does not track these customers.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.4: Is APS aware of any instances in which power flows from residential NEM systems interconnected at the secondary distribution voltage level have resulted in power being backfed onto APS's transmission system? If your response is anything except for an unqualified "no," please provide data indicating precisely when such backfeeding occurred and the costs incurred by APS as a result of that backfeeding.

Response: APS is not currently aware of any power backfed into APS's transmission system solely from residential NEM systems; however, APS is aware of several distribution feeders that have experienced reverse flow directly due to residential NEM systems.

Attached as APS15879 is a table showing APS's top 25 distribution feeders by interconnected residential NEM systems and the number of NEM systems connected to each. The eleven feeders that experienced reverse power flow in 2015 are designated in yellow.

To date, APS has not incurred equipment or system costs directly attributable to these reverse power flows. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of reverse power flows will only increase.

Reverse Power Flows in 2015 – Highest System Count NEM Distribution Feeders				
Feeder	NEM System Count	Lowest 15 Min	Lowest 15 Min 2015 (MWs)	Total Hours of Reverse Flow
1	848	5/8 @ 12:45	-0.9368	328.75
2	702	1/16 @ 13:15	0.0005	
3	689	5/9 @ 12:45	-2.0783	935.50
4	467	4/16 @ 13:00	-0.6794	133.25
5	451	5/8 @ 12:45	-0.5829	49.75
6	409	5/8 @ 12:45	-0.4658	184.50
7	402	3/15 @ 12:30	1.1599	
8	353	4/16 @ 10:30	0.0203	
9	338	8/7 @ 19:45	-0.0008	18.00
10	331	9/29 @ 10:15	-0.0011	2.25
11	324	10/8 @ 13:15	1.2314	
12	322	5/8 @ 13:30	-0.1282	15.75
13	284	11/17 @ 13:00	0.8633	
14	274	11/6 @ 13:30	0.8384	
15	268	4/16 @ 12:30	0.4930	
16	260	4/16 @ 12:30	0.6152	
17	258	11/5 @ 12:15	0.7298	
18	253	5/8 @ 13:45	-0.1101	29.00
19	229	4/27 @ 11:15	-0.0020	0.50
20	228	6/10 @ 9:15	0.0008	
21	224	4/16 @ 12:30	0.1960	
22	208	11/9 @ 10:15	1.0964	
23	202	9/2 @ 3:30	4.5452	
24	194	9/23 @ 3:00	2.2743	
25	189	3/9 @ 13:15	-0.0927	1.50

TASC'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 FEBRUARY 3, 2016

TASC 2.1: Please provide the following data from APS's 2014 Integrated Resource Plan (IRP), in Excel format.

a. The output data (including hourly production and emission costs in $/MWh) from the PROMOD IV runs for the four major IRP scenarios, as cited in the IR, pp. 55 and 97.

b. The data for the key inputs for the IRP PROMOD runs, including:

   1. Natural gas price forecast (IRP Figure 11);
   2. Carbon costs (IRP Figure 12);
   3. Loads;
   4. New resources; and
   5. Assumed retirements.

c. Unredacted Tables 19, 20, and 26.

d. Please provide any calculation that APS has performed of the additional up- or down-ramp costs associated with increasing amounts of solar generation, as discussed on page 43 of the IRP.

e. Please provide a quantitative example of how "as a matter of practice, APS routinely includes estimates of grid integration costs into its planning analytics," as stated on page 44 of the IRP.

f. Please provide unredacted Attachments C, D, and F (including all subparts) to the IRP in Excel format.

g. Please provide the details of APS's imputed debt calculations in Attachment D.10 of the IRP.

h. Please provide the data in Attachment D.10 for all four of the portfolios *Base Enhanced Renewables, Coal Reduction, Coal-to-Gas) modeled in the IRP.

i. Please provide the annual transmission capital additions from 2014-2029 in each of the four primary IRP scenarios.

j. Please provide the assumptions used in APS's application of the Societal Cost Test for the energy efficiency programs included in Tables 34 and 35 of the IRP. Include all avoided cost assumptions included in the Societal Benefits, in all years, for (1) energy, (2) generation capacity, (3) avoided line losses, (4) avoided T&D capacity, (5) avoided carbon and/or

environmental costs, and (6) any other avoided "societal" costs.

k. Please provide any calculations that APS has performed quantifying any of the four Distributed Energy risks discussed on page 17 of the IRP, for any of the IRP scenarios.

l. Please provide the capital costs and annual first-year revenue requirements associated with the future transmission projects listed on page 79 of the IRP.

Response: APS's response to these questions provides native Excel files only in those instances where a native file contains calculations (other than sums of columns) showing the derivation of the file content or where a printout of the content would be voluminous.

a. APS objects to this question for the following reasons: PROMOD hourly outputs in the IRP scenarios are not extracted in the normal course of modeling the APS system and would require additional model runs to retrieve the data. Moreover, retrieving this data would result in tens of thousands of documents in a document format unique to PROMOD. And, hourly PROMOD outputs contain system and unit-specific competitively confidential data.

b. The data for the key inputs for the IRP PROMOD runs are provided in the following files:

1. APS15808, Natural Gas Price Forecast (IRP Figure 11);
2. APS15809, Carbon costs (IRP Figure 12);
3. APS15810, Loads;
4. New resource assumptions are outlined in APS15820, provided in response to TASC Data Request 2.1(f); and
5. All cases in the IRP assume retirements of 220 MW of steam generation at Ocotillo on 9/30/2017. The coal reduction portfolio assumes retirement of Cholla 2 on 4/1/2016, and Cholla units 1 and 3 on 12/31/2024.

c. Table 19 (APS15811) and Table 26 (APS15812) are provided in unredacted form. Table 20 was provided in unredacted form in TASC Data Request 1.4.

d. APS utilized PROMOD to evaluate portfolio requirements under alternative scenarios. The cost of meeting ramping requirements is embedded in the 2014 portfolio costs from the model and is not separately identified. In addition, please see

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

This Exhibit includes the following Data Responses: Vote Solar DR 1.1, 2.1, 2.3, and 2.4

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
DECEMBER 14, 2015

Vote Solar 1.1: In an October 8, 2015 letter filed in Docket No. E-01345A-13-0248, APS stated that it has completed a cost of service study regarding solar customers. Please provide a copy of the cost of service study and supporting workpapers in executable Excel format with formulas and links intact.

Response: Attached are the following workpapers that support the cost of service study summary APS filed on October 8, 2015.

- The cost of service study (APS15744)
- The revenue requirement report (APS15745)
- The allocation factor workbook (APS15746)
- The 2014 load data (APS15747)
- The cost of service working model (APS15748) - please note this model is only provided in excel and is not part of the PDF package.

2014 Allocation Factor Input Page

Line No.	Customer Class	# of Customers	Energy Consumption (MWH)	Delivery Level %	CP (kW)	4CP (kW)	12CP (kW)	NCP (kW)	Ind. Max (kW)	Delivery Level %	Line No.
	Residential										
0	Residential - Solar Site (Energy Rates)	27,078	366,789		122,495	112,553	73,588	122,816	196,649		0
0	Residential - Solar Site (Demand Rates)	1,176	25,432		7,536	6,954	4,896	7,568	11,693		0
1	E-12 (No Solar)	468,372	3,576,849		947,566	886,097	847,799	1,106,357	2,137,411		1
2	ET-1 (No Solar)	140,696	2,328,525		706,794	637,055	439,842	802,832	1,176,152		2
3	ECT-1R (No Solar)	27,488	726,448		199,141	179,779	127,494	212,342	309,249		3
4	ET-2 (No Solar) w/ET-SP	288,729	4,030,856		1,172,586	1,060,109	751,280	1,341,792	2,168,198		4
5	ECT-2 (No Solar)	81,248	2,029,487		552,582	510,485	353,463	606,438	907,202		5
6	**Total Residential**	**1,044,789**	**13,081,066**		**3,708,700**	**3,392,032**	**2,398,072**	**4,202,145**	**6,908,554**		**6**
	General Service										
7	E-20	409	38,842		11,200	8,900	6,517	22,943	28,136		7
8	E-30,E-32 0-20kW	106,780	1,432,985		270,400	262,350	239,683	341,726	548,276		8
9	E-32 21-100kW	14,494	2,572,375		538,400	508,725	399,317	636,796	847,773		9
10	Total E-30, E-32 0-100kW	121,274	4,005,360		808,800	771,075	639,000	978,522	1,396,049		10
11	Total E-30, E-32 0-100kW @ Dist. Primary	53		0.001700					2,361	0.001684	11
12	Total E-30, E-32 0-100kW @ Secondary Txf	121,221		0.998300					1,393,698	0.998316	12
13	Total E-32 101-400kW	4,252	3,188,803		550,900	509,900	440,242	628,994	814,527		13
14	Total E-32 101-400kW @ Dist. Primary	35		0.012000					12,873	0.015804	14
15	Total E-32 101-400kW @ Secondary Txf	4,217		0.988000					801,654	0.984196	15
16	Total E-32 401-999kW	894	1,899,183		261,900	239,900	226,667	298,642	353,653		16
17	Total E-32 1,000+kW	101	1,188,116		184,000	158,750	123,558	195,966	244,300		17
18	Total E-32 401+kW	795	2,887,299	-	445,900	398,650	350,225	494,608	597,953		18
19	Total E-32 401+kW @ Transmission Level	5		0.005000					3,745	0.006263	19
20	Total E-32 401+kW @ Dist. Primary	57		0.132800					100,227	0.167617	20
21	Total E-32 401+kW @ Secondary Txf	733		0.862200					493,981	0.826120	21
22	**Total E-30,E-32**	126,321	10,081,462		1,805,600	1,679,625	1,429,467	2,102,124	2,808,529		22
23	E-32 TOU 0-20kW	204	3,519		500	500	583	837	1,384		23
24	E-32 TOU 21-100kW	132	34,740		5,000	4,550	4,133	5,788	8,100		24
25	Total E-32 TOU 0-100kW	336	38,259		5,500	5,050	4,716	6,625	9,484		25
26	Total E-32 TOU 0-100kW @ Dist. Primary	1		0.003200					50	0.005272	26
27	Total E-32 TOU 0-100kW @ Secondary Txf	335		0.996800					9,434	0.994728	27
28	E-32 TOU 101-400kW	73	70,694		10,800	10,200	9,000	11,668	15,770		28
	Total E-32 TOU 101-400kW @ Dist. Primary			0.114800					2,729	0.173050	
	Total E-32 TOU 101-400kW @ Secondary Txf			0.885200					13,041	0.826950	
29	E-32 TOU 401-999kW	43	132,818		18,500	16,200	14,992	19,860	24,674		29
30	E-32 TOU 1000+kW	14	131,780		15,200	16,525	15,467	23,900	30,200		30
31	Total E-32 TOU 401+kW	57	264,598		33,700	32,725	30,459	43,760	54,874		31
32	Total E-32 TOU 401+kW @ Dist. Primary	10		0.192100					9,110	0.166017	32
33	Total E-32 TOU 401+kW @ Secondary Txf	47		0.807900					45,764	0.833983	33
34	**Total E-32 TOU**	466	373,551		50,000	47,975	44,175	62,951	80,128		34
35	**General Service School TOU**	116	110,696		15,200	16,150	14,808	36,939	40,172		35
36	**Total E-34**	30	881,858		143,500	137,475	117,150	152,848	171,923		36
37	Total E-34 @ Transmission Level	3		0.138300					21,468	0.124870	37
38	Total E-34 @ Dist. Substation	-		0.000000					-	0.000000	38
39	Total E-34 @ Dist. Primary	18		0.652700					101,289	0.589153	39
40	Total E-34 @ Secondary Txf	9		0.209000					49,166	0.285977	40
41	**Total E-35**	37	2,127,615		255,500	255,400	245,900	288,761	336,110		41
42	Total E-35 @ Transmission Level	3		0.084300					20,189	0.060067	42
43	Total E-35 @ Dist. Substation	-		0.000000					-	0.000000	43
44	Total E-35 @ Dist. Primary	13		0.423200					101,332	0.301485	44
45	Total E-35 @ Secondary Txf	21		0.492500					214,589	0.638449	45
46	**Total General Service**	**127,379**	**13,613,822**		**2,281,000**	**2,145,525**	**1,858,017**	**2,663,866**	**3,464,998**		**46**
47	E-221	1,467	346,679		42,500	40,175	36,475	73,365	123,951		47
48	STREETLIGHTS	1,023	142,665		-	-	8,250	33,000	33,000		48
49	DUSK TO DAWN	8,319	22,969		-	-	1,325	5,300	5,300		49
50	**Total ACC**	**1,182,977**	**27,207,201**		**6,032,200**	**5,577,732**	**4,302,139**	**6,979,476**	**10,535,803**		**50**

2014 Allocation Factor Input Page

ENERGY Line Loss Values	
1.01300	(3) to (4)
1.00900	(4) to (5)
1.01800	(5) to (6)
1.00200	(6) to (7)
1.00906	(7) to (8)
1.02503	(8) to (9)
1.07837	

DEMAND Line Loss Values	
1.01900	(3) to (4)
1.01300	(4) to (5)
1.02600	(5) to (6)
1.00300	(6) to (7)
1.01201	(7) to (8)
1.01888	(8) to (9)
1.09532	

Revenue Credit Customers							
BHP MINERAL	1	49,916	9,800	5,225	5,942	15,200	15,200
MEXICO TAP BOSE	1	26,014	4,400	4,325	3,317	4,700	4,700
MEXICO TAP DEMDA	1	1,025	100	150	117	700	700
MEXICO TAP MECOX	1	1,344	300	250	200	500	500
MEXICO TAP PAULSON	1	4,594	900	900	667	1,300	1,300
SOLANA PLANT	1	34,343	-	-	2,968	20,100	20,100
DUKE ARLINGTON	1	18,331	-	-	183	17,000	17,000
HARQUAHALA PLANT	1	16,340	-	-	1,542	11,200	11,200
MESQUITE PLANT	1	2,658	-	-	158	9,600	9,600
PANDA PLANT	1	24,853	-	-	500	18,100	18,100
Total Revenue Credit Customers	10	177,420	15,500	10,850	15,584	98,400	98,400
	1,182,987	27,384,621	6,047,700	5,588,582	4,317,723	7,077,876	10,634,203
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - E-12 Solar Net	10,305	10,781	24,553	18,850	13,240	32,422	54,700
Residential - ET-1 Solar Net	5,119	29,873	21,273	17,434	11,808	25,898	39,869
Residential - ET-2 Solar Net	11,654	70,642	44,913	37,487	25,338	56,417	85,326
Residential - Solar Net (Energy Rates)	27,078	111,296	90,739	73,771	50,386	114,737	179,895
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,364	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - ECT-1 Solar Net	355	4,827	2,236	1,866	1,318	2,575	3,831
Residential - ECT-2 Solar Net	821	8,766	3,851	3,324	2,318	4,798	7,083
Residential - Solar Net (Demand Rates)	1,176	13,593	6,086	5,190	3,636	7,373	10,914
Residential - E-12 Solar Received	-	82,006	2,181	3,628	2,734	-	-
Residential - ET-1 Solar Received	-	31,321	633	1,211	992	-	-
Residential - ET-2 Solar Received	-	62,589	1,301	2,529	2,057	-	-
Residential - Solar Received (Energy Rates)	-	155,916	4,115	7,368	5,783	-	-
Residential - ECT-1 Solar Received	-	2,090	24	55	46	-	-
Residential - ECT-2 Solar Received	-	4,009	67	141	119	1	-
Residential - Solar Received (Demand Rates)	-	6,099	91	196	165	1	-
Residential - E-12 Solar Site	10,305	105,638	35,929	32,860	21,683	35,929	61,904
Residential - ET-1 Solar Site	5,119	82,880	27,748	25,227	16,476	27,748	43,617
Residential - ET-2 Solar Site	11,654	181,251	58,818	54,466	35,429	59,139	93,128
Residential - Solar Site (Energy Rates)	27,078	369,769	122,495	112,553	73,588	122,816	198,649
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - ECT-1 Solar Site	355	8,649	2,651	2,376	1,623	2,658	4,046
Residential - ECT-2 Solar Site	821	16,783	4,885	4,578	3,073	4,910	7,647
Residential - Solar Site (Demand Rates)	1,176	25,432	7,536	6,954	4,696	7,568	11,693
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,364	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - E-12 Solar (Customer Usage)		32,851	9,195	10,382	5,709	3,507	7,204
Residential - ET-1 Solar (Customer Usage)		21,688	5,842	6,582	3,676	1,850	3,748
Residential - ET-2 Solar (Customer Usage)		48,020	12,604	14,450	8,034	2,722	7,802
Residential - Solar (Customer Usage)(Energy Rates)		102,557	27,641	31,414	17,419	8,079	18,754
Residential - ECT-1 Solar (Customer Usage)		1,732	392	455	259	83	215
Residential - ECT-2 Solar (Customer Usage)		4,008	967	1,113	636	111	564
Residential - Solar (Customer Usage)(Demand Rates)		5,740	1,359	1,568	895	194	779
Residential - E-12 Total Solar Generation		94,857	11,376	14,010	8,443	3,507	7,204
Residential - ET-1 Solar Generation		53,007	6,475	7,793	4,668	1,850	3,748
Residential - ET-2 Solar Generation		110,609	13,905	16,979	10,091	2,722	7,802
Residential - Solar Generation (Energy Rates)		258,473	31,756	38,782	23,202	8,079	18,754
Residential - ECT-1 Solar Generation		3,822	416	510	305	83	215
Residential - ECT-2 Solar Generation		8,017	1,034	1,254	755	112	564
Residential - Solar Generation (Demand Rates)		11,839	1,450	1,764	1,060	195	779

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.1: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company provided a chart depicting the "Cost of Service Results for A Typical Solar Customer." Please provide all workpapers supporting this chart, including linked references to the Cost of Service Working Model provided by APS in response to VS 1.1.

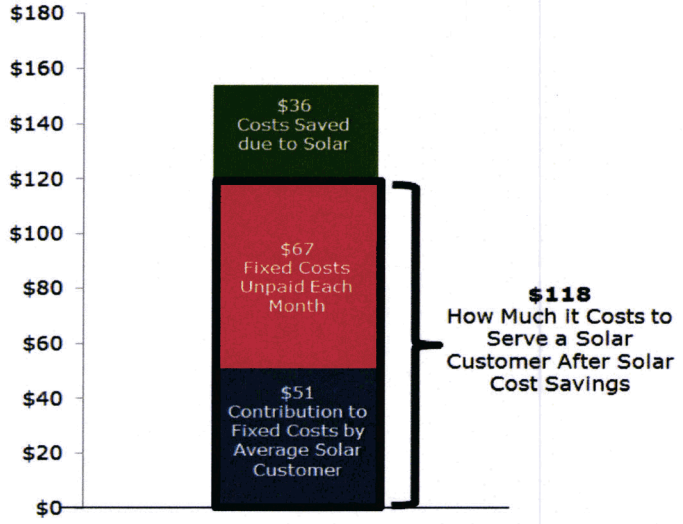
Response: See attached as APS15767 for the workpapers supporting this chart.

Back-Up for Chart:

	(A)		(B)	(C)	(D)
	Total Monthly Cost to Serve Typical Solar Customer		What Solar Customers Should Pay	What Solar Customers are Actually Paying	Unrecovered Amount (Column B-C)
Base Cost to Serve a Customer	$136		$104	$44	$61
Adjustors	$18		$14	$8	$6
Total	$154		$118	$51	$67

Costs Saved due to Solar	$36

Cost of Service Results for A Typical Solar Customer



Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission &	Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base														
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249		$0	$4,840,752	$0	$0	$3,019,457	$114,452,899
2)	Customer Accounts								$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense								$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)							(370,358)
5)	Customer Advances	(15,924)			(71,725)	(306,550)	(239,982)							($634,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972		$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -5.56%													
8)	Return on Rate Base (Line 6 * Line 7)	($2,759,039)	($72,780)	$0	($327,339)	($1,408,798)	($1,096,773)		($127,383)	($259,663)	($5,787)	($6,536)	($161,968)	($6,225,065)
Computation of Income Taxes														
9)	Weighted Cost of Long Term Debt @ 2.49%													
10)	Tax Rate @ 39.19%													
11)	Income Taxes ((Line 7-Line 9)/(Line 6)/(Line 10))/(1-Line 10)	($2,803,557)	($68,579)	$0	($308,692)	($1,329,408)	($1,034,022)		($120,204)	($245,029)	($5,460)	($6,167)	($152,839)	($5,874,254)
Expenses														
12)	Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$0	$1,337,751	$0	$0	$1,208,737	$29,172,005
13)	Customer Accounts	$0	$0	$0	$0	$0	$0		$1,533,621	$0	$304,542	$115,894	$0	$1,954,157
14)	Cust. Service & Info and Sales Expense	$0	$0	$0	$0	$0	$0		$700,635	$0	$0	$0	$0	$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$2,234,257	$1,337,751	$304,542	$115,894	$1,208,737	$31,826,798
Revenue Requirement														
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$2,667,259	$9,496,171	$3,561,494	($68,947)	$52,906	($91,648)		$1,986,670	$833,061	$293,395	$103,191	$893,932	$19,727,483
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584		$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @-5.56%**	**$1,068,886**	**$6,762,177**	**$2,714,428**	**($104,347)**	**($148,925)**	**($217,232)**		**$1,976,907**	**$811,050**	**$293,395**	**$103,191**	**$893,932**	**$14,153,463**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**		**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0040**	**0.0253**	**0.0102**	**-0.0004**	**-0.0006**	**-0.0008**		**0.0074**	**0.0030**	**0.0011**	**0.0004**	**0.0033**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**		**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$3.29**	**$20.81**	**$8.35**	**-$0.32**	**-$0.46**	**-$0.67**		**$6.08**	**$2.50**	**$0.90**	**$0.32**	**$2.75**	**$43.50**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission &	Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base														
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249			$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts								$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense								$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)							(370,358)
5)	Customer Advances	(15,924)			(71,725)	(306,550)	(239,982)							($634,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972		$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%													
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,511	$1,310,549	$1,019,356		$118,499	$241,564	$5,383	$6,080	$150,671	$5,790,935
Computation of Income Taxes														
9)	Weighted Cost of Long Term Debt @ 2.49%													
10)	Tax Rate @ 39.19%													
11)	Income Taxes ((Line 7-Line 9)/(Line 6)/(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,322	$423,157	$329,135		$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
Expenses														
12)	Expenses	8,029,855	9,637,630	3,561,494	567,284	2,791,108	2,038,147			$1,337,751			$1,208,737	$29,172,005
13)	Customer Accounts								1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense								$700,635					$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$2,234,257	$1,337,751	$304,642	$115,894	$1,208,737	$31,826,798
Revenue Requirement														
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$11,425,211	$9,727,195	$3,561,494	$976,116	$4,524,814	$3,386,638		$2,391,017	$1,657,299	$311,763	$123,937	$1,406,057	$39,487,542
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584		$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @4.99%**	**$9,826,838**	**$6,993,201**	**$2,714,428**	**$894,717**	**$4,322,984**	**$3,261,054**		**$2,381,255**	**$1,635,289**	**$311,763**	**$123,937**	**$1,406,057**	**$33,913,522**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**		**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0368**	**0.0262**	**0.0102**	**0.0036**	**0.0162**	**0.0122**		**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1269**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**		**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$30.24**	**$21.51**	**$8.35**	**$2.75**	**$13.30**	**$10.04**		**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$104.36**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$26.95**	**$0.70**	**$0.00**	**$9.20**	**$13.78**	**$10.70**		**$1.24**	**$2.54**	**$0.06**	**$0.06**	**$1.58**	**$60.80**

Residential Targeted ROR	Weighted Residential ROR
Rate Base	$ 5,800,521,490
Operating Income	192,457,609
Current Rate of Return	3.32%

Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement before Energy Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				($42,810)	($184,243)	($143,305)						(370,358)
5)	Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -10.77%												
8)	Return on Rate Base (Line 6 * Line 7)	($5,539,575)	($146,127)	$0	($657,233)	($2,828,587)	($2,200,060)	($256,757)	($521,347)	($11,618)	($13,122)	($325,194)	($12,498,621)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($4,395,555)	($115,949)	$0	($521,503)	($2,244,418)	($1,745,725)	($202,939)	($413,680)	($9,219)	($10,412)	($258,036)	($9,917,435)
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$342,121	$17,444,818	$3,561,494	($611,452)	($2,281,877)	($1,907,658)	$1,775,559	$402,725	$283,805	$92,359	$625,507	$19,727,401
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @-10.77%**	**($1,256,252)**	**$14,710,824**	**$2,714,428**	**($948,852)**	**($2,483,708)**	**($2,033,242)**	**$1,765,796**	**$380,715**	**$283,805**	**$92,359**	**$625,507**	**$14,153,380**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**-0.0047**	**0.0551**	**0.0102**	**-0.0024**	**-0.0093**	**-0.0076**	**0.0066**	**0.0014**	**0.0011**	**0.0003**	**0.0023**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**-$3.87**	**$45.27**	**$8.35**	**-$1.99**	**-$7.64**	**-$6.26**	**$5.43**	**$1.17**	**$0.87**	**$0.28**	**$1.93**	**$43.56**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5)	Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						(636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,323	$423,157	$329,135	$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,672,606	$17,796,459	$3,561,494	$970,120	$4,524,814	$3,386,636	$2,391,017	$1,657,299	$311,763	$123,937	$1,408,057	$49,804,202
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @4.99%**	**$12,074,233**	**$15,062,465**	**$2,714,428**	**$934,720**	**$4,322,983**	**$3,261,052**	**$2,381,254**	**$1,635,289**	**$311,763**	**$123,937**	**$1,408,057**	**$44,230,181**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0452**	**0.0564**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1655**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.16**	**$46.36**	**$8.35**	**$2.88**	**$13.30**	**$10.04**	**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$136.11**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$41.02**	**$1.07**	**$0.00**	**$4.67**	**$20.95**	**$18.29**	**$1.89**	**$3.88**	**$0.09**	**$0.10**	**$2.41**	**$92.55**

Note: The target ROR of 4.99% is the average residential non-solar ROR.

	Demand Credit	Energy Credit
Line 12 before credits	**$10,277,250**	**$17,706,894**
Line 12 after credits	**$8,029,855**	**$9,537,530**
Difference is the credits	**($2,247,395)**	**($8,169,364)**

	Weighted Residential ROR
Residential Targeted ROR	
Rate Base	$ 3,609,521,490
Operating Income	192,467,995
Current Rate of Return	5.33%

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.3: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company stated that its cost of service study "incorporates and credits to solar customers the measurable costs that APS avoids when a customer installs rooftop solar."

a) Please list the categories of avoided costs that APS incorporated into its cost of service study.

b) Please describe the methodology APS used to calculate each category of avoided costs listed in response to subquestion (a).

c) For each category of avoided costs listed in response to subquestion (a), please describe where the Cost of Service Working Model provided in response to VS 1.1 calculates each avoided cost.

Response: a & b. In the cost of service study, the avoided costs for which APS credited solar customers are:

- A "Production Demand Credit" which provides the solar customers with a credit for their reduced demand on APS's system. This was calculated by taking the total megawatts APS delivers to the customer as a percent of the customer's total site load (see APS's response to VS 2.4.c 'Solar Site' for a description of this term) for both non-coincident and coincident peak during the 4 system peak months of the year (June-September). This is consistent with the "average and excess" method of allocating production demand cost required by the ACC. This then derived a blended average that credits the solar customers for offsetting a portion of APS's peak load. The total amount credited for solar energy customers was $2.2M (or a reduction of 18.66% in their production demand cost) and for solar demand customers it was $109k (or a reduction of 14.64% in their production demand cost). See APS15768.

- An "Energy Fuel Credit" which provides the solar customers with a credit for the energy they actually produce. This is calculated by first grossing up their total energy production to recognize the line loss benefit. Then APS applied the EPR-6 excess generation rate (see APS15773 for a copy of the EPR-6 tariff) to the grossed

up amount of energy produced to calculate the Energy Fuel Credit. This amount is then credited to the solar energy customers. The total amount credited for solar energy customers was $8M and for solar demand customers it was $370k. See APS15768.

- An explicit "Transmission Credit" was not developed in this study. However, transmission costs were allocated on a delivered energy basis. This is conservative and over-credits solar energy customers for avoided transmission. A more precise method would be to allocate cost at the 4 system coincident peak months and credit the difference based on the delivered data.

- A "Distribution Credit" was not applied since the non-coincident peak occurred at nearly the same time for both site and delivered data, thus indicating no significant avoided distribution costs.

No other avoided costs existed as a results of rooftop solar generation.

c. The credits are inputs into the working model, but attached as APS15768 are the workpapers that calculate each avoided cost mentioned above. The calculation is done as a separate analysis using load data and information from the cost of service and then the credits are applied in the O&M report in the cost of service, which reduces the overall cost to serve those customers.

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Energy Credit
Test Year Ending 12/31/2014

	Customer Class	MWhs @ Customer Level	MWhs @ Generation Level	EPR-6 Fuel Rate (cents/kWh)	2014 Solar Fuel Credit
1.	Residential - Solar Generation (Energy Rates)	258,473	278,731	2.895	$8,069,264
2.	Residential - Solar Generation (Demand Rates)	11,839	12,767	2.895	$369,612
3.	Total	270,312	291,498		$8,438,876

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Demand Credit
Test Year Ending 12/31/2014

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
1.	Residential - Solar Generation (Energy Rates)				
	June	76.5	104.1	93.4	104.8
	July	94.9	122.5	111.3	122.5
	August	93.2	119.8	94.2	105.1
	September	60.0	103.8	99.2	107.1
	Average	81.2	112.6	99.5	109.9
	Relationship - Delivery versus Site		27.90%		9.42%
	Peak 2 Point Average				**18.66%**

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
2.	Residential - Solar Generation (Demand Rates)				
	June	5.1	6.5	6.1	6.6
	July	6.2	7.5	7.1	7.5
	August	6.2	7.5	6.0	6.5
	September	4.0	6.3	6.2	6.6
	Average	5.4	7.0	6.4	6.8
	Relationship - Delivery versus Site		22.66%		6.62%
	Peak 2 Point Average				**14.64%**

Calculation of Demand Credit - Residential - Solar Generation (Energy Rates)

	Revenue Requirement @ -6.54% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$51,435,445	$51,435,445
Return on Rate Base	($3,363,878)	$2,566,629
Taxes	($3,023,197)	$798,893
Expense	$10,277,250	$10,277,250
Revenue Credits	($1,598,373)	($1,598,373)
Revenue Requirement @ -6.54% (before Demand Credit)	$2,291,802	$12,044,399
% Difference in Delivery vs. Site		**18.66%**
Solar Demand Credit		**$2,247,395**

Residential - Solar Generation (Demand Rates)

	Revenue Requirement @ .79% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$3,289,477	$3,289,477
Return on Rate Base	$25,987	$164,145
Taxes	($37,948)	$51,092
Expense	$651,121	$651,121
Revenue Credits	($119,754)	($119,754)
Revenue Requirement @ -6.54% (before Demand Credit)	$519,406	$746,604
% Difference in Delivery vs. Site		**14.64%**
Solar Demand Credit		**$109,301**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Energy Rates - SITE)

		Unbundled Functional Revenue Requirement											
		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				($42,810)	($184,243)	($143,305)						($370,358)
5)	Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -6.54%												
8)	Return on Rate Base (Line 6 * Line 7)	($3,363,878)	($88,735)	$0	($399,101)	($1,717,633)	($1,335,987)	($155,307)	($316,585)	($7,055)	($7,968)	($197,472)	($7,589,723)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10)/(1-Line 10)	($3,023,197)	($79,748)	$0	($358,682)	($1,543,677)	($1,200,684)	($139,578)	($284,523)	($6,341)	($7,161)	($177,473)	($6,821,064)
	Expenses												
12)	Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$31,419,401
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$3,890,175	$9,469,147	$3,561,494	($190,499)	($470,202)	($498,524)	$1,939,370	$736,643	$291,246	$100,764	$833,791	$19,663,406
17)	Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18)	**REVENUE REQUIREMENT @-6.54%**	**$2,291,802**	**$6,735,153**	**$2,714,428**	**($225,899)**	**($672,033)**	**($624,108)**	**$1,929,607**	**$714,633**	**$291,246**	**$100,764**	**$833,791**	**$14,089,385**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0086**	**0.0252**	**0.0102**	**-0.0008**	**-0.0025**	**-0.0023**	**0.0072**	**0.0027**	**0.0011**	**0.0004**	**0.0031**	**0.0527**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$7.05**	**$20.73**	**$8.35**	**-$0.70**	**-$2.07**	**-$1.92**	**$5.94**	**$2.20**	**$0.90**	**$0.31**	**$2.57**	**$43.36**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

		Unbundled Functional Revenue Requirement											
		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5)	Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10)/(1-Line 10)	$798,893	$21,074	$0	$94,783	$407,923	$317,286	$36,884	$75,186	$1,676	$1,892	$46,898	$1,802,496
	Expenses												
12)	Expenses	10,277,250	9,637,630	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$31,419,401
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,642,772	$9,726,408	$3,561,494	$966,580	$4,509,580	$3,374,787	$2,389,639	$1,654,491	$311,701	$123,866	$1,406,306	$41,667,625
17)	Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18)	**REVENUE REQUIREMENT @4.99%**	**$12,044,399**	**$6,992,414**	**$2,714,428**	**$931,180**	**$4,307,749**	**$3,249,203**	**$2,379,876**	**$1,632,481**	**$311,701**	**$123,866**	**$1,406,306**	**$36,093,604**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0451**	**0.0262**	**0.0102**	**0.0035**	**0.0161**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1351**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.07**	**$21.51**	**$8.35**	**$2.87**	**$13.26**	**$10.00**	**$7.32**	**$5.02**	**$0.96**	**$0.38**	**$4.33**	**$111.07**
23)	**Under Recovery (Targeted less Actual)[$/Cust/Month]**	**$30.01**	**$0.78**	**$0.00**	**$3.56**	**$15.33**	**$11.82**	**$1.39**	**$2.82**	**$0.06**	**$0.07**	**$1.76**	**$67.71**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Demand Rates - SITE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809	$0	$210,234			$207,678	$6,998,345
2)	Customer Accounts							$77,924		$4,685	$5,292		$87,901
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				($5,961)	($25,655)	($18,125)						(49,741)
5)	Customer Advances	($1,018)			($9,983)	($42,966)	($30,355)						($84,322)
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7)	Actual Earned ROR @ 0.79%												
8)	Return on Rate Base (Line 6 * Line 7)	$25,987	$737	$0	$2,900	$12,483	$8,819	$815	$1,661	$37	$42	$1,641	$55,121
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($37,948)	($1,077)	$0	($4,235)	($18,228)	($12,878)	($1,190)	($2,425)	($54)	($61)	($2,396)	($80,493)
	Expenses												
12)	Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594		$58,099			$83,137	$2,237,527
13)	Customer Accounts							$66,605		$13,231	$5,033		$84,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$639,160	$875,903	$241,673	$40,338	$166,242	$109,535	$113,308	$57,335	$13,214	$5,014	$82,382	$2,344,103
17)	Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18)	**REVENUE REQUIREMENT @0.79%**	**$519,406**	**$672,933**	**$144,226**	**$40,338**	**$164,061**	**$97,098**	**$106,278**	**$53,680**	**$12,258**	**$5,014**	**$82,382**	**$1,897,673**
19)	**Energy Consumption (MWh)**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20)	**Functional Unit Costs (cents/kWh)**	**0.0264**	**0.0342**	**0.0073**	**0.0020**	**0.0083**	**0.0049**	**0.0054**	**0.0027**	**0.0006**	**0.0003**	**0.0042**	**0.0964**
21)	**Number of Customers**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22)	**Functional Unit Costs ($/Customer/month)**	**$36.81**	**$47.70**	**$10.22**	**$2.86**	**$11.63**	**$6.88**	**$7.53**	**$3.80**	**$0.87**	**$0.36**	**$5.84**	**$134.46**

Residential Solar @ Targeted ROR (Demand Rates - SITE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809		$210,234			$207,678	$6,998,345
2)	Customer Accounts							77,924		4,685	5,292		$87,901
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				(5,961)	(25,655)	(18,125)						(49,741)
5)	Customer Advances	(1,018)			(9,983)	(42,966)	(30,355)						($84,322)
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$164,145	$4,657	$0	$18,320	$78,847	$55,705	$5,146	$10,491	$234	$264	$10,363	$348,172
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$51,092	$1,449	$0	$5,702	$24,542	$17,339	$1,602	$3,265	$73	$82	$3,226	$108,373
	Expenses												
12)	Expenses	651,121	876,242	241,673	41,673	171,988	113,594		$58,099			$83,137	$2,237,527
13)	Customer Accounts							66,605		13,231	5,033		$84,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$866,358	$882,348	$241,673	$65,696	$275,377	$186,638	$120,431	$71,855	$13,538	$5,379	$96,726	$2,826,019
17)	Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18)	**REVENUE REQUIREMENT @4.99%**	**$746,604**	**$679,378**	**$144,226**	**$65,696**	**$273,196**	**$174,201**	**$113,401**	**$68,200**	**$12,582**	**$5,379**	**$96,726**	**$2,379,589**
19)	**Energy Consumption (MWh)**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20)	**Functional Unit Costs (cents/kWh)**	**0.0379**	**0.0345**	**0.0073**	**0.0033**	**0.0139**	**0.0088**	**0.0058**	**0.0035**	**0.0006**	**0.0003**	**0.0049**	**0.1208**
21)	**Number of Customers**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22)	**Functional Unit Costs ($/Customer/month)**	**$52.91**	**$48.13**	**$10.22**	**$4.66**	**$19.36**	**$12.34**	**$8.04**	**$4.83**	**$0.89**	**$0.38**	**$6.85**	**$168.61**
23)	**Under Recovery (Targeted less Actual)[$/Cust/Month]**	**$16.10**	**$0.44**	**$0.00**	**$1.80**	**$7.73**	**$5.46**	**$0.50**	**$1.03**	**$0.02**	**$0.03**	**$1.02**	**$34.13**

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.4: Regarding APS's Response to VS 1.1:

Please provide the following information regarding VS 1.1_2014 COS Load Data_APS15747.xlsm.

a) Please describe the methodology APS used for the load data analysis.

b) Please indicate whether the load data shown for solar customers is the result of a statistical sampling of a subset of actual APS solar customers. If so, please describe the sampling methodology and indicate what proportion of APS solar customers were included in the sample. If not, please describe the derivation of the solar customer load data.

c) Please describe the meaning of the following terms as used in the titles of the spreadsheet tabs: "No Solar," "Solar Delivered," "Solar Site," "Solar Del," and "Solar Net."

Response:

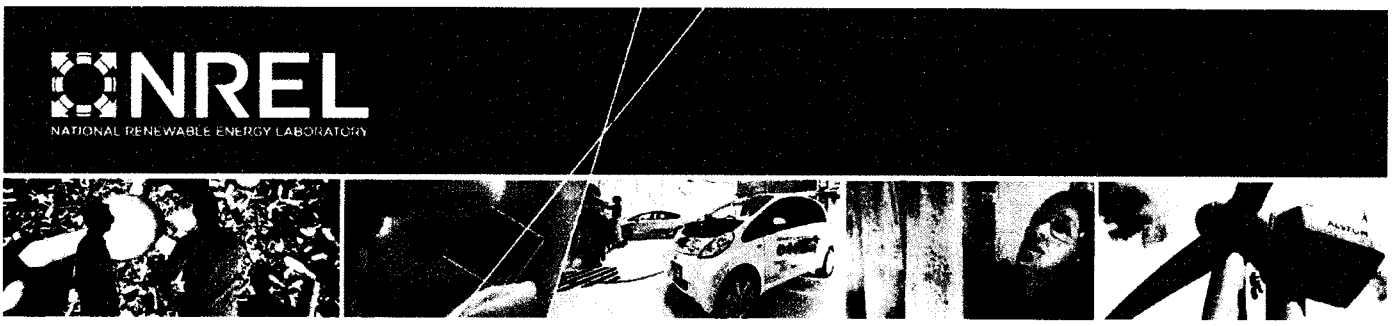
a.) APS queries its energy data "warehouse" for all Residential AMI interval data. The AMI data is then sorted into the corresponding rates and categories (i.e. "No Solar", "Solar Delivered", "Solar Site", and "Solar Net"). A mean-per-unit analysis technique is then used to obtain the peak values for the report.

b.) APS's load data shown for solar customers is based on all solar customers' interval data.

c.) Term Definitions are as follows:

- *No Solar* – measured energy delivered from APS to customers who are not on a solar rate.
- *Solar Del / Solar Delivered* – measured energy delivered from APS to customers on a solar rate.
- *Solar Site* – the energy used by a customer based on the following formula: [Delivered Electricity + (Produced Electricity – Received Electricity)], where Delivered Electricity means energy delivered from APS to the customer and Received Electricity means energy delivered from the customer to APS.
- *Solar Net* – the energy used by a customer based on the following formula: [Delivered Electricity – Received Electricity].

Exhibit WAM-4: Excerpt from
"Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures,"
National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015



Effects of Home Energy Management Systems on Distribution Utilities and Feeders under Various Market Structures

Preprint

Mark Ruth, Annabelle Pratt, Monte Lunacek, Saurabh Mittal, Hongyu Wu, and Wesley Jones
National Renewable Energy Laboratory

Presented at the 23rd International Conference on Electricity Distribution
Lyon, France
June 15–18, 2015

NREL is a national laboratory of the U.S. Department of Energy
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Conference Paper
NREL/CP-6A20-63500
July 2015

Contract No. DE-AC36-08GO28308

controllers and custom reduced-order building models [10]. The model predictive controllers were also only run once per day, and a real-time price was provided as an input, based on historical CAISO prices and weather.

In this paper, we describe the IESM's structure. We then define the scenario used in the analysis; report results on the impact of HEMS technology on a feeder; and provide conclusions and propose future work.

INTEGRATED ENERGY SYSTEM MODEL

The Integrated Energy System Model (IESM) is being developed to analyze interactions between multiple technologies within various market and control structures, and to identify financial and physical impacts on both utilities and consumers. Physical impacts include both consumer comfort (e.g., difference between actual and desired temperature) and distribution feeder operations including voltage profiles and equipment loading. In addition, the IESM will be dynamically integrated into hardware in the loop (HIL) testing of technologies in the National Renewable Energy Laboratory's (NREL's) Energy Systems Integration Facility (ESIF) by providing market signals to technologies and equipment.

To meet these objectives, the IESM is being designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure. The IESM uses co-simulation, wherein multiple simulators with specific modeling capabilities co-operate towards a common objective of bringing the capabilities together in a shared execution environment, and manages time and data exchange between component models. The co-simulation execution is performed on a high-performance computer (HPC).

In the current version, GridLAB-D, which performs distribution feeder, household, and market simulations, is co-simulated with Pyomo [11], which implements a HEMS for each household. GridLAB-D is an agent-based, open source power system simulation tool developed by the Pacific Northwest National Laboratory. It performs quasi-steady state simulations for distribution feeders, including end-use loads such as heating-cooling systems, water heaters and electric vehicles. It also manages retail markets and responses to market signals [8]. Similar to [10], the wholesale market is not included.

The IESM can include both price responsive thermostats, responding to the current price, and model predictive controllers which can be run several times during the day, which models the operation of such devices more realistically. In the reported case, the IESM utilizes HEMS, implemented in Pyomo, minimizes its house's cooling cost using a model predictive control approach and sets the cooling setpoint to a calculated optimal value while constrained by an envelope around the desired temperature [12]. No custom HVAC model was developed for the HEMS, instead, through the IESM's co-simulation structure, models available in existing software simulation packages are accessed.

Ultimately, the IESM will utilize an internal discrete event coordinator that operates on abstract time and an enterprise message bus as shown in Figure 1. The scheduler is expected to manage GridLAB-D's simulation of distribution feeders; actual or simulated loads and DER either in experimental hardware, GridLAB-D, or another simulation package such as Energy Plus [13]; and simulation of technologies, such as HEMS, markets, and consumers. Component libraries allow the creation of comprehensive scenarios, including different types of houses and market structures in a plug-and-play component-based manner.

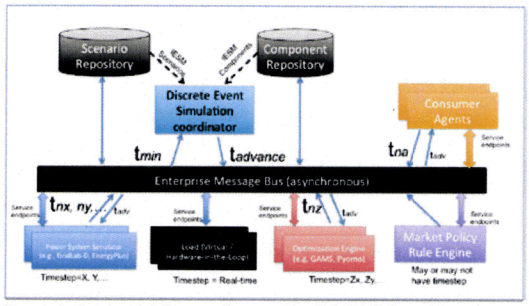

Figure 1. Integrated Energy System Model (IESM) architecture

SCENARIO DEFINITION

A scenario was created for a distribution feeder in the state of North Carolina in the Southeast of the United States in the summer for the month of July when air conditioning use is high. A distribution feeder based on the IEEE 13-node test feeder is used and about 3% of the load is replaced with houses in order to provide a price-responsive, varying load component [14].

The feeder is populated with 20 well-insulated houses with identical parameters, which are connected through four 25 kVA single-phase, center-tapped transformers – each serving 5 houses. The air conditioner in the house is modeled explicitly, and the rest of the household loads are modelled as a lumped ZIP load with a time-varying base power profile. The desired cooling temperature profile is motivated by EPA's Energy Star Recommendations [15]. The desired profile for each house is different, as shown in Figure 2. Each house has a desired daytime temperature between 72° and 77° F (22.2-25.0°C) that is set at uniformly distributed random time between 4:00 AM and 8:00 AM. The desired daytime temperature is constant for 16 hours and is set back by 3°F (1.7°C) at night for 8 hours. Each household's ZIP load base power profile has the same shift in time as the desired temperature.

Two retail electricity tariff structures that are currently in place for households in North Carolina are used. The first has a flat structure with a constant electricity price of $0.093587/kWh and a monthly service fee of $11.80 [16]. The TOU rate structure is shown in Figure 3. It has a varying electricity price with peak, shoulder, and off-peak rates and a monthly service fee of $14.13. The peak, shoulder, and off-peak rates are $0.2368/kWh,

$0.11961/kWh, and $0.06936/kWh, respectively. Summer peak hours are 1:00 PM to 6:00 PM, Monday through Friday and shoulder rates are in effect during the two hours before and after the peak hours [17]. All weekend hours are off-peak. Vertical shaded areas in this and other figures indicate peak and should pricing time periods.

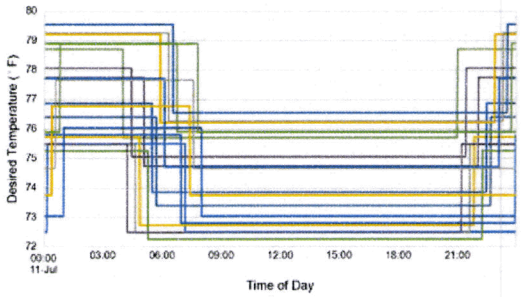

Figure 2. Desired temperature profile for each of the houses in the simulation. Daytime temperatures are randomly distributed between 72 and [illegible] (22.2-25.0°C), set at a random time between 4:00 and 8:00 AM. After 16 hours, the desired temperature increases by 3°F (1.7°C).

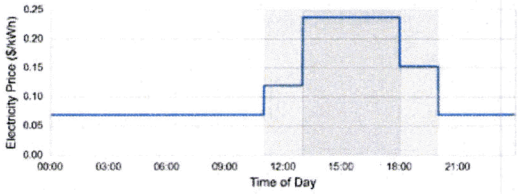

Figure 3. Time-of-use pricing profile for weekdays. All weekend hours are off-peak and have the lowest price

Three HEMS penetrations (0%, 50%, and 100%) are simulated to show how IESM can be used to evaluate the physical and financial impacts of distributed technologies, such as HEMS, in the presence of different markets or tariffs, on the system. Each house's HEMS uses model predictive control to adjust the cooling setpoint from the desired temperature to minimize cost. The HEMS does not allow the setpoint to be above the desired temperature, but does allow it to be down to 5°F (2.8°C) below the desired temperature so that the house can be precooled before peak electricity prices.

RESULTS

Figure 4 shows the range of electricity expenses for the households in the population. Those expenses vary because of variations in desired temperatures and their profiles between houses. For the time period analyzed, the uniform tariff has a lower cost than TOU due to high demand for cooling and other loads during peak hours. Presumably, that load will not be as large at other times of the year and bills under TOU tariffs will be lower during those seasons. Under TOU tariffs, bills are about 5% lower when HEMS are used to manage cooling.

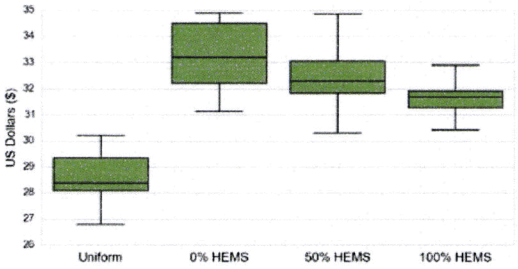

Figure 4. Box plot of the population's electricity bills over the time period from July 7-17, 2012. Use of HEMS reduces each household's bill by about 5%.

Cost savings are driven by the use of power during off-peak and shoulder times for precooling the houses. Figure 5 displays the total cooling power of all the houses over each day with vertically shaded bars indicating peak-price hours and shoulders. The solid lines display the mean total cooling loads over all 11 days, and the shaded areas indicates a 95% confidence interval. Results for the uniform price distribution are identical to the scenario with 0% HEMS penetrations.

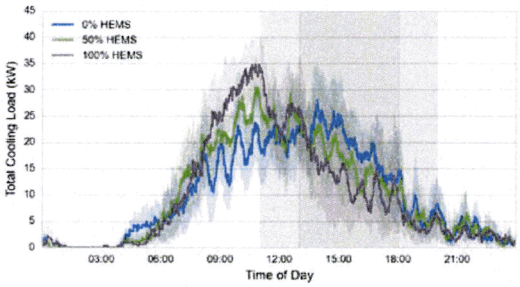

Figure 5. Daily profile of total cooling power load at several levels of HEMS penetrations. When HEMS are present, power use is shifted from peak hours to earlier times when it is less expensive.

When HEMS are present, power use is shifted from times when cost is higher (peak-price periods from 1:00 PM to 6:00 PM) to earlier hours when it is not as expensive. In addition, with the HEMS penetration levels simulated here, the peak is higher during the time period before prices increase than at any time without HEMS. The HEMS used in this study does not adjust any other household loads so they are not shifted due to pricing.

Figure 6 shows the total load on the distribution transformers. The solid line shows the mean and the shaded area shows a 95% confidence interval. The peak load during peak pricing is reduced with the HEMS penetration levels simulated here, but a new, higher peak load is created during the time period before peak pricing. Because the peak load is just shifted, the distribution feeder still experiences peak stress even though the TOU rate structure was likely designed to reduce the peak load.

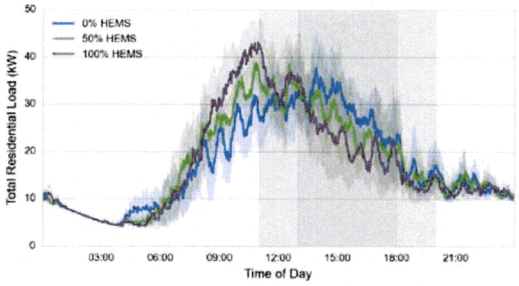

Figure 6. Daily profile of the total distribution transformer load with several HEMS penetrations. Presence of HEMS reduces the peak load during peak pricing but creates a new peak load in the time period before peak pricing is in effect.

Using power to precool intrinsically indicates that the house's temperature setpoint is lower than desired for a time before the peak pricing period. Figure 7 shows the daily profile of the population's average temperature over all days with and without HEMS. The solid line shows the mean and the shaded area shows a 95% confidence interval. The average of the population with HEMS precools by almost 2°F (1.2°C) as compared to the population without HEMS (i.e., without cost optimization). Note that the starting time for cooling is consistent because the two populations have the same time for the initial house's change in desired temperature and, during that time, the setpoint for both is the desired temperature.

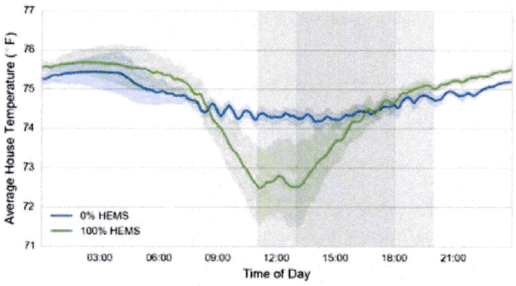

Figure 7. Daily profile of mean household temperature for the population with and without HEMS. HEMS minimize cost by precooling by about 2°F (1.1°C) before peak pricing is in place.

Figure 8 shows the daily profile of the primary voltage of the distribution transformer at node 652. It serves five houses. The solid lines display the mean and the shaded area indicates a 95% confidence interval. With HEMS, the lowest voltage is experienced at an earlier time in the day, coinciding with the peak transformer load moving earlier due to precooling. The minimum voltage is lower in this case, due to the fact that the peak transformer load is higher with HEMS than without. Overall the voltage variation is small due to the fact that only a small percentage of the load at this node is replaced with houses that provide a time-varying load component.

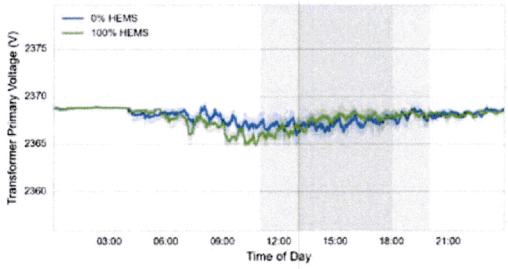

Figure 8. Daily profile of primary voltage of the transformer at node 652 and serving five houses. Use of HEMS shifts time of low voltage to coincide with new peak introduced by HEMS.

Utility net revenue is calculated as the difference between income from the household electricity bills reported above and the wholesale cost of the electricity provided. The wholesale cost of the electricity is calculated as the product of the total electricity demand for the feeder and the Midcontinent Independent Service Operations hourly real-time locational marginal prices for a hub in North Carolina (price node 746136) and are assumed to be unaffected by the modelled changes in the load.

Table 1: Comparison of household expenditures and utility net revenue between scenarios

	Sum of household expenditures	Utility net revenue
Uniform rate	$573	$470
TOU rate – 0% HEMS	$665	$562
TOU rate – 50% HEMS	$650	$547
TOU rate – 100% HEMS	$632	$530

Table 1 shows the utility net revenue and the total household expenditure for the four scenarios. Utilizing HEMS reduces the sum of household expenditures by $33 in the time period analyzed, but only reduces the utility net revenue by $32. Where bulk power prices are unaffected by load, utility net revenue is reduced by approximately the same amount as household expenditure reductions; thus, indicating that the TOU rate structure provides similar net revenue at all times.

CONCLUSIONS AND FUTURE WORK

This paper presented results from a specific scenario simulated using a co-simulation platform, the Integrated Energy System Model (IESM), under development to study the physical and economic impact of distributed technologies under different markets or tariff structures.

The results reported here show that the combination of time-of-use (TOU) pricing and Home Energy Management Systems (HEMS) controlling residential cooling systems reduces peak load during high price hours but moves the load peak to hours with off-peak and shoulder prices. This situation would be further exacerbated with HEMS that are able to shift the operation of multiple loads within a household in

Exhibit WAM-5: Excerpt from
"Energy Star: Program Requirements for Programmable Thermostats,"

ENERGY STAR® Program Requirements for Programmable Thermostats

Partner Commitments
DRAFT 1

Commitment

The following are the terms of the ENERGY STAR Partnership Agreement as it pertains to the manufacturing of ENERGY STAR qualified programmable thermostats. The ENERGY STAR Partner must adhere to the following program requirements:

- comply with current ENERGY STAR Eligibility Criteria, defining the performance criteria that must be met for use of the ENERGY STAR certification mark on programmable thermostats and specifying the testing criteria for programmable thermostats. EPA may, at its discretion, conduct tests on products that are referred to as ENERGY STAR qualified. These products may be obtained on the open market, or voluntarily supplied by Partner at EPA's request;

- comply with current ENERGY STAR Identity Guidelines, describing how the ENERGY STAR marks and name may be used. Partner is responsible for adhering to these guidelines and for ensuring that its authorized representatives, such as advertising agencies, dealers, and distributors, are also in compliance;

- qualify at least one ENERGY STAR qualified programmable thermostat model within one year of activating the programmable thermostat portion of the agreement. When Partner qualifies the product, it must meet the specification (e.g., Tier 1 or 2) in effect at that time;

- provide clear and consistent labeling of ENERGY STAR qualified programmable thermostats. The ENERGY STAR mark must be clearly displayed on the front/inside of the product, on the product packaging, in product literature (i.e., user manuals, spec sheets, etc.), and on the manufacturer's Internet site where information about ENERGY STAR qualified models is displayed;

> **Note:** EPA requires the labeling of all ENERGY STAR qualified products according to one or more of the following options, depending on product design and visibility at both the time of sale and over the use of the product: on the product; in product literature; and on the manufacturer's Internet site. The ENERGY STAR mark is well known by consumers and large purchasers as the symbol for energy efficiency. The ENERGY STAR mark should be placed in an area of high visibility, preferably on front of the product, so that the purchaser and end users can see that by purchasing and using an ENERGY STAR qualified programmable thermostat, they are helping to reduce air pollution and greenhouse gases through energy efficiency. EPA is open to discussing additional placement options.

- provide to EPA, on an annual basis, an updated list of ENERGY STAR qualifying programmable thermostat models. Once the Partner submits its first list of ENERGY STAR qualified programmable thermostat models, the Partner will be listed as an ENERGY STAR Partner. Partner must provide annual updates in order to remain on the list of participating product manufacturers;

- provide to EPA, on an annual basis, unit shipment data or other market indicators to assist in determining the market penetration of ENERGY STAR. Specifically, Partner must submit the total number of ENERGY STAR qualified programmable thermostats shipped (in units by model) or an

1. **Default Program**. The setbacks and setups periods are required to be a **minimum of** 8 hours, but may exceed 8 hours. Partners must have four events on the weekday and two on the weekend, partners may choose to add additional setbacks and/or setups as long as the setback/setup period is at least eight-hours long. Listed below are the suggested events along with setbacks/setups and appropriate temperatures (Tables 1-3).

Table 1: Programmable Thermostat Setpoint Temperatures

Events	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Day	setback at least 8°F (4.4°C)	setup at least 8°F (3.8°C)
Evening	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Night	setback at least 8°F (4.4°C)	setup at least 3°F (2.2°C)

Table 2: Acceptable Weekday Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	6 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	8 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	10 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Table 3: Acceptable Weekend Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	8 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	10 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	11 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Exhibit WAM-6: Excerpt from

Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Hardware Design of Smart Home Energy Management System With Dynamic Price Response

Qinran Hu, *Student Member, IEEE*, and Fangxing Li, *Senior Member, IEEE*

***Abstract*—The smart grid initiative and electricity market operation drive the development known as demand-side management or controllable load. Home energy management has received increasing interest due to the significant amount of loads in the residential sector. This paper presents a hardware design of smart home energy management system (SHEMS) with the applications of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can easily achieve a real-time, price-responsive control strategy for residential home loads such as electrical water heater (EWH), heating, ventilation, and air conditioning (HVAC), electrical vehicle (EV), dishwasher, washing machine, and dryer. Also, consumers may interact with suppliers or load serving entities (LSEs) to facilitate the load management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then a machine learning algorithm is applied to intelligently help consumers reduce total payment on electricity without or with little consumer involvement. Finally, simulation and experiment results are presented based on an actual SHEMS prototype to verify the hardware system.**

***Index Terms*—Controllable load, demand response, dynamic pricing, embedded system, machine learning, optimal control strategies, peak shaving, remote operation, smart home energy management system (SHEMS).**

NOMENCLATURE

F_i	Signals from sensors.
C	User's activity.
$X_T(t)$	Temperature in electrical water heater at time t, °C.
$X_a(t)$	Ambient temperature at time t, °C.
a	Thermal resistance of tank walls, W/°C.
$A(t)$	Rate of energy extraction when water is in demand at time t.
$q(t)$	Status of the hot water demand at time t, ON/OFF.
P_{EWH}	Power rating of the heating element, W.
P_{EV}	Power rating of charging station, W.
P_H	Power rating of dishwasher, washing machine, or dryer, W.
$m(t)$	Thermostat binary state at time t, ON/OFF.
$RTP(t)$	Real time price at time t, \$/MWh.
$S_{EV}(t)$	Status of charging station, ON/OFF.
TF_{EV}	The time EV needs to get fully charged (hour).
R_{EV}	Desired percentage of battery being charged.
T_{start}	The time when EV is connected to charging station.
T_{end}	The time when the user needs to drive EV.
T_{hstart}	The time when dishwasher, washing machine, or dryer starts to work.
T_{huse}	Time duration for dishwasher, washing machine, and dryer to complete the work once started.
T_{hready}	The time when dishwasher, washing machine, and dryer is ready to use.
T_{hend}	The time when the user needs to pick up things from the dishwasher, the washing machine or the dryer.

Manuscript received October 14, 2012; revised February 26, 2013 and April 04, 2013; accepted April 04, 2013. Date of publication June 06, 2013; date of current version November 25, 2013. This work was supported by the NSF under Grant ECCS 1001999. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program. Paper no. TSG-00720-2012.

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Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSG.2013.2258181

I. INTRODUCTION

THE electricity prices in a competitive power market are closely related to the consumers' demand. However, the lack of real-time pricing (RTP) technologies presents challenges to electricity market operators to optimally signal and respond to scarcity, because electricity cannot be stored economically [1]. In the past a few years, the deployment of advanced metering infrastructures (AMI) and communication technologies make RTP technically feasible [2]. RTP, generally speaking, reflects the present supply-demand ratio and provides a means for load-serving entities (LSEs) and independent system operators (ISOs) to solve issues related to demand side management such as peak-load shaving. Applications of RTP enable consumers and suppliers to interact with each other, which also creates an opportunity for consumers to play an increasingly active role in the present electricity market with optimal control strategies at the demand side.

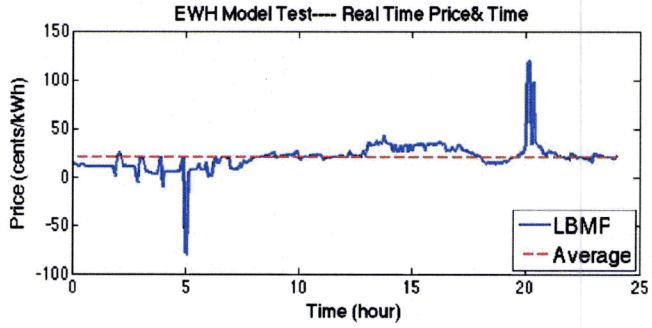

Fig. 11. Real time price curve for 24 hours.

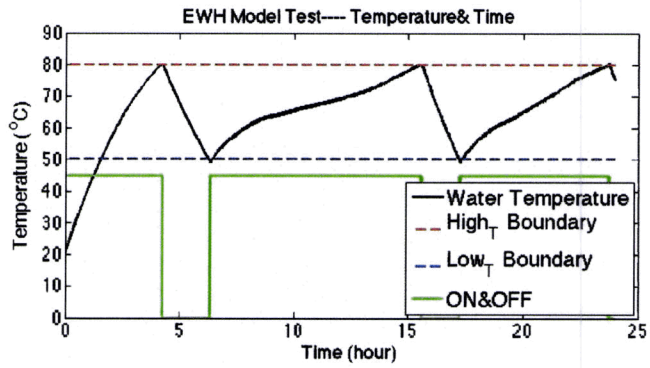

Fig. 12. Typical EWH strategy [26].

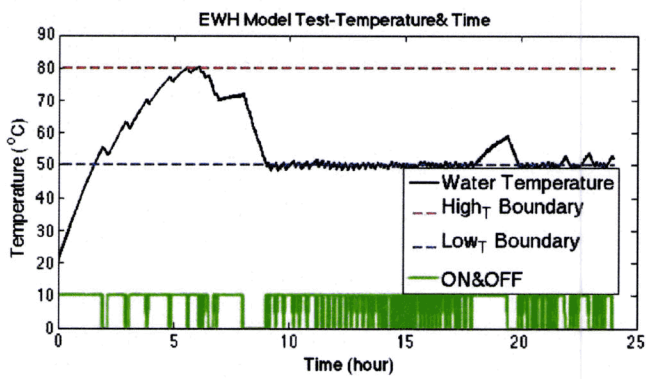

Fig. 13. Optimized EWH strategy.

signal may change as fast as every 5 minutes which is a discrete variable. The model can be described by:

$$\frac{dX_T}{dt} = -a\left(X_T(t) - X_a(t)\right) - A(t)q(t) + P_{EWH} \cdot m(t) \quad (2)$$

Table II shows the specifications of EWH used in the experiment. For testing and simulation purposes, Table III shows some useful information applied here. Also, a typical water usage curve as shown in Fig. 10 is obtained from [25].

In this study, the locational marginal price (LMP) on a randomly selected day from NYISO is used as the real-time price, which is shown in Fig. 11. The result without SHEMS is shown in Fig. 12, and the results after applying an RTP-responsive algorithm to change the ON and OFF strategy of EWH is shown in Fig. 13.

The optimized strategy used in the test can be further improved in future algorithm/software studies, while this paper focuses on the hardware part. Nevertheless, the straightforward algorithm still works greatly. A brief description of the algorithm is presented next.

The principle of the algorithm is to turn EWH on for a while before the dropping temperature reaches the lower bound. Meanwhile, the algorithm also considers whether the EWH can provide comfortable hot water based on the predicted consumer demand of water usage with a look-ahead consideration. For example, the algorithm will preheat the EWH to a higher temperature before the consumer takes a shower. The mathematical description is an optimization model given below.

$$\min \int_0^{24} RTP(t) \cdot m(t) \cdot P_{EWH} \quad (3)$$

$$\text{s.t.}: \quad \text{Eq. (2)}$$

$$T_{low} \leq X_T(t) \leq T_{high} \quad (4)$$

Since $RTP(t)$ refreshes every 5 minutes, this model given by (2), (3), and (4) is discretized into a time interval of 5 minutes. The genetic algorithm (GA), an intelligent search algorithm using stochastic operations, is customized in this work to solve the model to find the global optimal scheduling for the EWH. With this approach, SHMES can reduce the total payment and energy consumption while meeting the consumer's needs.

The result verifies that SHEMS helps reduce the thermostat ON time by 14%, while reducing the consumer's payment by 60% of the original payment on heating water.

The proposed SHEMS system has been programmed and tested to connect and disconnect a mock EWH load in accordance with Fig. 13.

B. Heating, Ventilation, and Air Conditioning (HVAC)

The American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) has compiled modeling procedures in its Fundamentals Handbook [27]. The Department of Energy has produced the Energy Plus program for computer simulation [28]. Also, the detailed model for simulating HVAC systems is given in [29], [30]. Accurate model for energy consumption needs to consider many factors including weather, season, thermal resistance of rooms, solar heating, cooling effect of the wind, and shading. Unlike EWH which has constant and relatively accurate parameters, those HVAC parameters are difficult to be precisely modeled with the possibility to change over the time due to other factors.

Thus, the testing here is not based on any detailed model but relies on the actual measurement from the experiments performed at the University of Tennessee with the SHEMS prototype and a portable HVAC unit.

In this experiment, the SHEMS optimizes the HVAC based on three parameters: the mock RTP from the prices in a randomly selected day in NYISO used in the previous EWH test, the real-time temperature in the test room, and the temperature setting by the user. Table IV shows the related parameters.

For comparison purpose, a parameter named "Comfort Level" is considered here. In market economics, a consumer has to compromise between quality and price. The introduction of "Comfort Level" is based on similar idea for home energy management. Simply speaking, "Comfort Level" in this case

TABLE IV
HVAC PARAMETERS IN THE TEST

Room Area	800 sq ft
Room Type	Single room
HVAC Power Rate	3.5kW
Room Temperature Setting	73°F (23°C)

TABLE V
HVAC RESULTS WITH SHEMS

	Different Comfort Level		
	+/- 0°C	+/- 3°C (5.8°F)	+/- 5°C (9°F)
Energy Consumption (% w.r.t the case w/o SHEMS)	91%	79%	72%
Payment (% w.r.t the case w/o SHEMS)	86%	73%	64%

means the difference between the actual indoor temperature and the temperature desired by the consumer.

Table V shows the energy consumption and the total payment reduction of the cases under different comfort levels with SHEMS. The results are in percentage with respect to the case without SHEMS. As shown in the table, considerable reduction of energy consumption and payment is achieved. Further, if a consumer can tolerate a higher temperature difference, more payment or credit to HVAC from the supplier can be achieved. This is sensible from the standpoint of market economics.

C. EV, Dishwasher, Washing Machine and Dryer

In order to fully exploit the potential of SHEMS and contribution to the power grid, low cost is an important characteristic of the prototype. Since considering bidirectional power flow will significantly increase the total cost of SHEMS design, the electric vehicle (EV) model in the proposed prototype is to charge a battery. That is, this design of SHEMS does not include the consideration for EV to send power back to grid.

Loads such as charging the battery for an EV are interruptible [15]. It is possible to charge the battery for 1 h, then stop charging for another hour, and then finish the charging after that. In contrast, the loads like dishwasher, washing machine and dryer demonstrate similar features to EV, but differ from EV considerably because they are uninterruptible. That is, as soon as the corresponding appliance starts operation, its operation should continue till completion.

1) Electrical Vehicles: An EV should be fully charged, for example, at 8 A.M. but the EV user does not care when or how the EV battery is charged. Therefore, SHEMS chooses the possible hours with the low electricity price to charge. Meanwhile, SHEMS must make sure EV to be fully charged before being used at 8 A.M..

As an interruptible load, the mathematical expression of the discrete model of EV can be expressed in (5) and (6). Since the real-time price refreshes every 5 minutes, the time interval of discrete model is also set to 5 minutes. Here, $S_{EV}(t)$ is the optimal solution that needs to be generated by SHEMS.

TABLE VI
PARAMETERS OF DISHWASHER, WASHING MACHINE, AND DRYER

	Model	P_H (W)	T_{huse} (min)
Dishwasher	Danby	1000	30
Washing machine	Danby	400	45
Dryer	Whirlpool	3000	40

$$\min \sum_{t=T_{start}}^{T_{end}} P_{EV} \cdot RTP(t) \cdot S_{EV}(t) \tag{5}$$

$$\text{s.t.}: \frac{1}{12} \cdot \sum_{t=T_{start}}^{T_{end}} S_{EV}(t) = TF_{EV} R_{EV} \tag{6}$$

2) Dishwasher, Washing Machine, and Dryer: As an uninterruptible load, the mathematical expression of the discrete model of dishwasher, washing machine and dryer can be all expressed in (7), (8), and (9), respectively. The time interval of discrete model is also set to 5 minutes. T_{hstart} is the optimal solution which needs to be generated by SHEMS.

$$\min \sum_{t=T_{hstart}}^{T_{hstart}+T_{huse}} P_H \cdot RTP(t) \tag{7}$$

$$\text{s.t.}: T_{hready} \leq T_{hstart} \leq T_{hend} \tag{8}$$

$$T_{hready} \leq (T_{hstart} + T_{huse}) \leq T_{hend} \tag{9}$$

D. Effects of SHEMS in Load Shifting

Based on the previous analysis on EWH and HVAC, it is rational to conclude that SHEMS can make substantial contribution to reduce home energy consumption from not only EWH and HVAC but also EV, dishwasher, washing machine, dryer, etc. To study the effect of SHEMS in a large-scale system, this section demonstrates a comparison on the load curves with and without SHEMS.

The simulation here is to give a quantified verification that SHEMS will play a critical role in load shifting. The total real-time load curve (including residential, commercial, industrial and other) is selected from NYISO again. The date of the data is the same as the date of the selected RTP.

The EWH and HVAC parameters are the same as from the previous Sections V-B and V-C. The EV parameters are chosen based on Nissan Leaf [31] for this simulation study:

- Charging power rate: approx. 6 kW;
- Battery volume: 24 kWh;
- Time of fully charging: 4 hour; and
- The percentage of EV battery to be charged is set as 100%.

The parameters of dishwasher, washing machine, and dryer are shown in Table VI.

The reduction of energy consumption from individual appliance is scaled up to simulate the optimized residential load consumption. The results are shown in Fig. 14, which illustrates that SHEMS can help with load shifting. In addition, it reduces the loads in peak hours by nearly 10 percent which is significant.

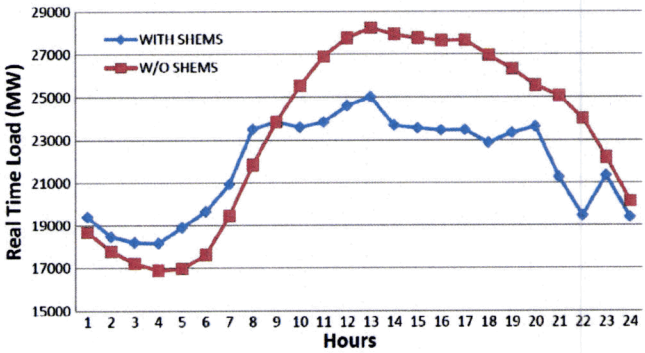

Fig. 14. Load curve comparison with and without SHEMS.

VI. Comparative Analysis and Conclusion

A. Comparative Analysis

As mentioned in the Introduction, there are several companies working on products related to demand response. However, those early products do not take full considerations of all aspects mentioned in this paper. Most of these previous products focus on displaying and monitoring the status of home energy consumption. Some advanced ones may help analyze power usages of different appliances, then offer tips for conserving energy and reducing payment in electricity, which is represented by the "Indirect Feedback" [32], [33]. None of those previous works has reported any real intelligent control down to the appliance level, and users' interaction is needed. However, the proposed design and the actual prototype carried out in our Smart Home lab implements automated, intelligent controls for smart home energy management to the appliance level.

As for the cost, the proposed design typically costs less than $200 with off-the-shelf retail prices for materials and components. The actual cost also depends on the number of appliances that consumers want to install load interfaces, as well as the number of rooms to be monitored. Here is the cost breakdown in a typical case. The main controller costs around $80 based on to the off-the-shelf retail price($15 for a microcontroller, $20 for making PCB and accessories, $15 Wi-Fi module, and $30 for touch screen). Each load interface and room monitoring unit costs around $20 ($15 for Wi-Fi module and $5 for accessories). With the assumption that a consumer wants to control HVAC and EWH, and has 3~4 rooms to monitor, the total cost will be around $200 in this typical setting. In addition, this design is expandable and can be easily upgraded by updating programs running in the processor without any change of existing hardware.

Table VII provides a high-level comparison of the proposed design and 4 SHEMS-like devices from commercial vendors. These 4 devices include Monitor12 by Powerhouse, Home monition and Control by Verizon, Nucleus by GE, and Thermostat controller by NEST. The listed features are monitoring, remote control, real-time price responsive, machine learning, and easy setting. They are randomly named Vendor 1 to 4 without any particular order in Table VII. One of the vendor's cost is the annual service cost, while the device is sold separately. The cost

TABLE VII
Comparison of Existing SHEMS

Name	Appliances	Monitor /Control	Response	Learn	Easy Setting	Cost ($)
Proposed Design	Extendable	X	X	X	X	~200
Vendor 1	Vendor's own devices	X	X			199
Vendor 2	12 switches	X				1024
Vendor 3	Extendable	X				120/yr
Vendor 4	Thermostat	X		X	X	250

of the system from Vendor 1 is relatively low, but with relatively simple functions. It does not have machine learning algorithm and cannot provide optimized schedule for home appliances. Vendor 4 provides a fancy user interface which is easy and efficient, but cannot control appliances other than HVAC.

Note that the cost of the developed prototype may not be directly comparable with the costs of the four vendors' products since the cost of the developed prototype does not include labor cost and the expected profit. However, on the other hand, the prototype cost is based on retail prices of various materials and components, which are usually higher than wholesale prices under mass production. Nevertheless, the cost information is listed in Table VII for future references.

B. Conclusion

This paper presents a hardware design of a smart home energy management system (SHEMS) with the application of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can achieve a RTP-responsive control strategy over residential loads including EWHs, HVAC units, EVs, dishwashers, washing machines, and dryers. Also, they may interact with suppliers or load serving entities (LSEs) to facilitate the management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then apply machine learning algorithm to intelligently help consumers reduce total electricity payment without much involvement of consumers. In order to verify the effort, this paper also includes testing and simulation results which show the validity of the hardware system of the SHEMS prototype. The expandable hardware design makes SHEMS fit to houses regardless of its size or number of appliances. The only modules to extend are the sensors and load interfaces.

Also, if this design can be widely used in the future, the administrator-user structure will provide good potentials for electricity aggregators. Most likely, utilities may not be interested or motivated to administrate all individual, millions of end consumers directly and simultaneously. Therefore, electricity aggregators can play as agents between consumers and utilities. This business mode may facilitate the popularity of SHEMS or similar systems and create win-win results for all players.

Acknowledgment

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TABLE IV
HVAC PARAMETERS IN THE TEST

Room Area	800 sq ft
Room Type	Single room
HVAC Power Rate	3.5kW
Room Temperature Setting	73°F (23°C)

TABLE V
HVAC RESULTS WITH SHEMS

	Different Comfort Level		
	+/- 0°C	+/- 3°C (5.8°F)	+/- 5°C (9°F)
Energy Consumption (% w.r.t the case w/o SHEMS)	91%	79%	72%
Payment (% w.r.t the case w/o SHEMS)	86%	73%	64%

means the difference between the actual indoor temperature and the temperature desired by the consumer.

Table V shows the energy consumption and the total payment reduction of the cases under different comfort levels with SHEMS. The results are in percentage with respect to the case without SHEMS. As shown in the table, considerable reduction of energy consumption and payment is achieved. Further, if a consumer can tolerate a higher temperature difference, more payment or credit to HVAC from the supplier can be achieved. This is sensible from the standpoint of market economics.

C. EV, Dishwasher, Washing Machine and Dryer

In order to fully exploit the potential of SHEMS and contribution to the power grid, low cost is an important characteristic of the prototype. Since considering bidirectional power flow will significantly increase the total cost of SHEMS design, the electric vehicle (EV) model in the proposed prototype is to charge a battery. That is, this design of SHEMS does not include the consideration for EV to send power back to grid.

Loads such as charging the battery for an EV are interruptible [15]. It is possible to charge the battery for 1 h, then stop charging for another hour, and then finish the charging after that. In contrast, the loads like dishwasher, washing machine and dryer demonstrate similar features to EV, but differ from EV considerably because they are uninterruptible. That is, as soon as the corresponding appliance starts operation, its operation should continue till completion.

1) Electrical Vehicles: An EV should be fully charged, for example, at 8 A.M. but the EV user does not care when or how the EV battery is charged. Therefore, SHEMS chooses the possible hours with the low electricity price to charge. Meanwhile, SHEMS must make sure EV to be fully charged before being used at 8 A.M..

As an interruptible load, the mathematical expression of the discrete model of EV can be expressed in (5) and (6). Since the real-time price refreshes every 5 minutes, the time interval of discrete model is also set to 5 minutes. Here, $S_{EV}(t)$ is the optimal solution that needs to be generated by SHEMS.

TABLE VI
PARAMETERS OF DISHWASHER, WASHING MACHINE, AND DRYER

	Model	P_H (W)	T_{huse} (min)
Dishwasher	Danby	1000	30
Washing machine	Danby	400	45
Dryer	Whirlpool	3000	40

$$\min \sum_{t=T_{start}}^{T_{end}} P_{EV} \cdot RTP(t) \cdot S_{EV}(t) \tag{5}$$

$$\text{s.t.}: \frac{1}{12} \cdot \sum_{t=T_{start}}^{T_{end}} S_{EV}(t) = TF_{EV} R_{EV} \tag{6}$$

2) Dishwasher, Washing Machine, and Dryer: As an uninterruptible load, the mathematical expression of the discrete model of dishwasher, washing machine and dryer can be all expressed in (7), (8), and (9), respectively. The time interval of discrete model is also set to 5 minutes. T_{hstart} is the optimal solution which needs to be generated by SHEMS.

$$\min \sum_{t=T_{hstart}}^{T_{hstart}+T_{huse}} P_H \cdot RTP(t) \tag{7}$$

$$\text{s.t.}: T_{hready} \leq T_{hstart} \leq T_{hend} \tag{8}$$

$$T_{hready} \leq (T_{hstart} + T_{huse}) \leq T_{hend} \tag{9}$$

D. Effects of SHEMS in Load Shifting

Based on the previous analysis on EWH and HVAC, it is rational to conclude that SHEMS can make substantial contribution to reduce home energy consumption from not only EWH and HVAC but also EV, dishwasher, washing machine, dryer, etc. To study the effect of SHEMS in a large-scale system, this section demonstrates a comparison on the load curves with and without SHEMS.

The simulation here is to give a quantified verification that SHEMS will play a critical role in load shifting. The total real-time load curve (including residential, commercial, industrial and other) is selected from NYISO again. The date of the data is the same as the date of the selected RTP.

The EWH and HVAC parameters are the same as from the previous Sections V-B and V-C. The EV parameters are chosen based on Nissan Leaf [31] for this simulation study:

- Charging power rate: approx. 6 kW;
- Battery volume: 24 kWh;
- Time of fully charging: 4 hour; and
- The percentage of EV battery to be charged is set as 100%.

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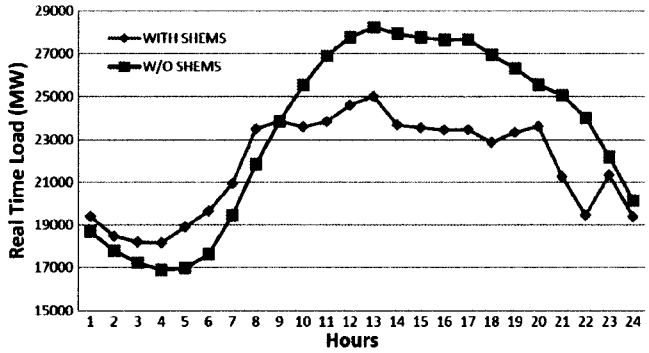

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Exhibit WAM-7: Excerpt from

California Energy Markets, Issue No. 1379, April 1, 2016

AN INDEPENDENT NEWS SERVICE FROM ENERGY NEWSDATA

CALIFORNIA ENERGY MARKETS

◆ Friday, April 1, 2016 ◆ No. 1379 ◆

BILLBOARD No. 1379

Gas-Storage Reform Bill Moves Ahead in State Senate ..... [5]

Utilities Try Algae to Reduce Power Plant CO_2..... [6]

EPA Defends Clean Power Plan in Court Filing..... [7]

Developer: Deal Near for LNG Project That FERC Nixed..... [8]

FPPC Opens Investigation of Brown Aide ..... [8.1]

Bottom Lines: 'Cattle Call' Inappropriate for SGIP..... [9]

SDG&E Seeks OK of Storage, Efficiency Contracts..... [11.1]

Cal-ISO Board Approves Transmission Plan..... [14.1]

Stump's Cell-Phone Messages to Stay Secret ..... [17]

Enel Touts Solar-Geothermal Hybrid Power Plant..... [17.1]

Judge Rejects Referendum on Nevada NEM Rates..... [17.2]

Western Price Survey

Despite Rains, California Drought Persists ..... [10]

[1] CARB Sets Sights on Including International Offsets in Cap and Trade

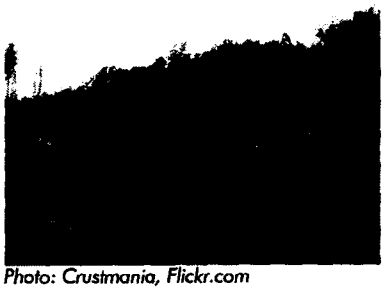


Photo: Crustmania, Flickr.com

The California Air Resources Board is considering whether to allow programs aimed at reducing GHG emissions from tropical deforestation to count as offset credits in the state's cap-and-trade program. Initiatives that prevent deforestation are a critical part of addressing global climate change, and may even provide for direct environmental benefits within California, according to CARB. Energy companies are advocating for additional sources of offsets, saying they are needed for cost containment. ***Sinking carbon at [13].***

[2] Cal-ISO: Resources Adequate to Meet Summer Loads

Cal-ISO expects to have adequate resources to meet summer demand. Peak demand should be up slightly in 2016, based on projected economic growth and new behind-the-meter solar installations, while hydroelectric capacity is projected to be near normal for both spring and summer. Cal-ISO did warn, however, of possible natural gas curtailments related to the Aliso Canyon natural gas storage facility. Meanwhile, the growth of rooftop solar helped cancel transmission upgrades planned for the Pacific Gas & Electric service area. ***At [14], generation and transmission.***

[3] CEC to Allow More Time for Puente Review

NRG Energy calls its Puente Power Project, a 262 MW natural gas plant proposed on the Southern California coast at Oxnard, "a bridge to California's energy future." Project opponents this week called for the California Energy Commission to allow more time to evaluate and comment on its environmental review of that "bridge." ***At [11], the CEC says it plans to revise its proposed schedule for Puente.***

[4] Davis, Yolo County to Form JPA for Launch of CCA Program

The City of Davis and Yolo County have agreed to form a joint-powers authority that will administer a community choice aggregation program, with the launch of service expected in 2017. The CCA would serve electricity customers in Davis and unincorporated areas of the county, in competition with incumbent utility Pacific Gas & Electric. The door is open for other cities in Yolo County to join in the aggregation effort down the road. ***At [15], stronger together?***

[14.1] Cal-ISO Board Approves Annual Transmission Plan

Thirteen new transmission projects with an estimated $288 million-dollar price tag were approved for construction by the Cal-ISO Board of Governors to ensure continued grid reliability.

According to the ISO's 2015-2016 Transmission Plan, each of the 13 projects costs less than $50 million and two-thirds are high-voltage upgrades needed to address reliability. None of the projects planned are policy- or economically-driven, which means there will be no need to take projects out for competitive bids, according to Cal-ISO, which approved the plan at its March 25 board meeting.

The transmission plan also called for canceling 13 sub-transmission projects in the Pacific Gas & Electric service area valued at $192 million. Some of these projects were originally approved in 2005. Of these, only two needed board approval—the Monta Vista-Wolfe and Newark-Applied Materials substation upgrades. Both 115 kV substation-upgrade projects were valued at $1 million each. However, Neil Millar, executive director of infrastructure development for Cal-ISO, said it is valuable "to get these cleared out of the way to focus on other projects going forward."

'We really appreciate the reappraisal of those projects.'

In his remarks to the board, Eric Eisenman, director of ISO relations and FERC policy for PG&E, conveyed the utility's support for the plan, including the project cancellations.

"The need for those is just not there anymore," he said. "We really appreciate the reappraisal of those projects." Load forecast has flattened in the service area from a combination of energy efficiency and rooftop solar, which eliminates the need for these upgrades, Eisenman said.

The utility plans to work with Cal-ISO on planning to prevent overbuilding and to ensure customers have affordable services. Future surveys, Eisenman said, would need to consider resources in the Oakland-East Bay area, which has an aging generation plant that may go off line. Roughly two-thirds of PG&E's $1 billion transmission budget is used to address maintenance and replacement of aging infrastructure.

This year's Cal-ISO transmission plan is "light" compared to previous plans, noted Steve Berberich, the grid operator's president and CEO, in his comments to the board. The 2012-2013 and 2013-2014 transmission plans were project-heavy to address issues in the PG&E service area and reliability requirements created by the early retirement of Units 2 and 3 of the San Onofre Nuclear Generating Station.

Among the new reliability projects identified in the 2015-2016 transmission plan are seven different projects, at a projected cost of $202 million, in the PG&E service area, including the reconductoring of the Panoche-Ora Loma 115 kV line and the Wilson 115 kV static VAR compensator (SVC) project.

Five projects are in the San Diego Gas & Electric service area and one is in the Southern California Edison service area. There are no projects planned in the Valley Electric Association service area in this planning cycle.

None of the transmission projects address the 2020 or 2030 renewables portfolio standards; however, Millar says there is a pressing need to better manage generation from renewable sources, which creates wider changes in operating conditions. Ultimately, this will require more voltage support across the system. The system operator is seeing "the impacts in real time" and needs to address these and other voltage-control issues, Millar said.

An upgrade to the Lugo-Victorville 500 kV line is needed, Millar and Berberich said, but Cal-ISO is coordinating with the Los Angeles Department of Water & Power on the project. A detailed cost-benefits analysis is needed because it is an interregional project, which pushes it into the 2016-2017 planning cycle. The needs of the Los Angeles Basin and San Diego areas specific to 230 kV loading in the region will also be addressed in that time frame.

Striving to meet the 50 percent RPS may require looking carefully at transmission needs. "As the system is changing in ways we hadn't historically anticipated," said Berberich, "we're going to have to be agile around re-evaluating the transmission system and what's really needed.

"There are lots of moving parts." *–L. D. P.*

[14.2] Cal-ISO Approves Changes to Commitment Cost-Bidding Process

The Cal-ISO Board of Governors on March 25 approved changes to the commitment cost-bidding process after weighing concerns that the proposal might hinder the use of preferred resources and did not adequately address concerns from demand-response providers.

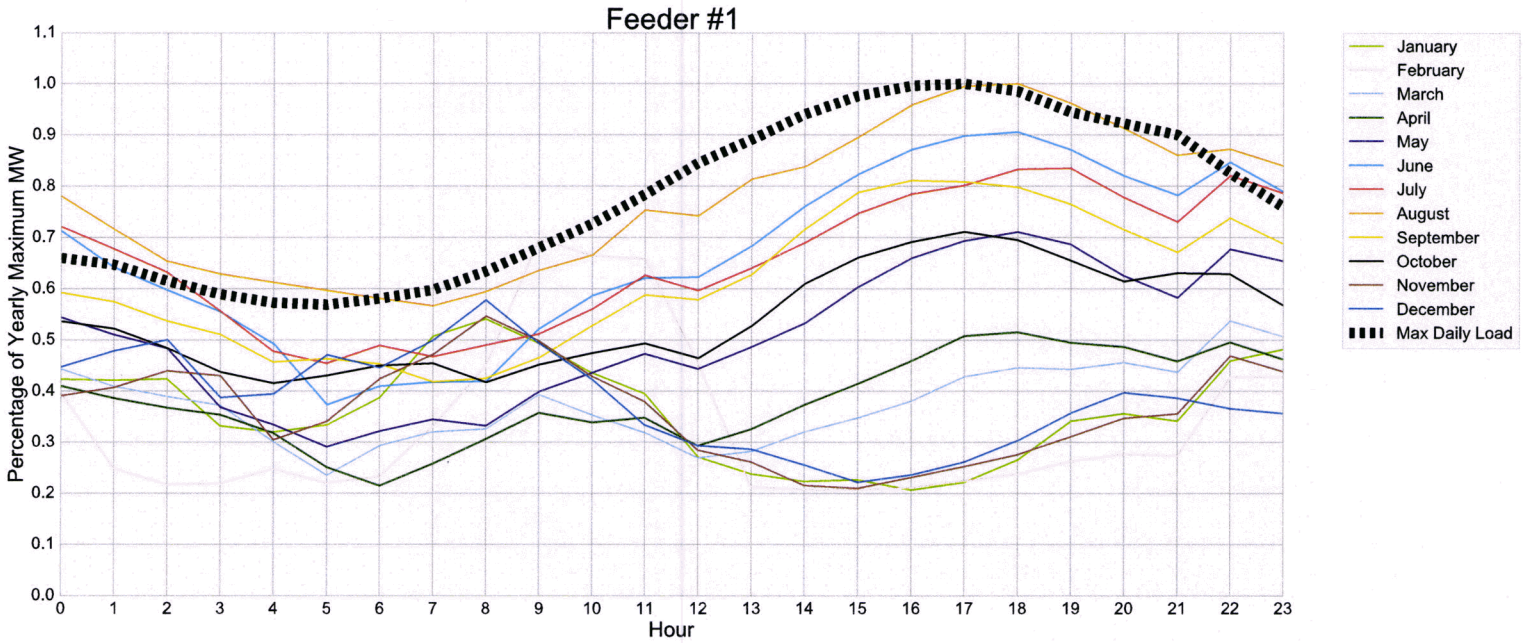
Under the changes, use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. The move will allow the ISO to eliminate the "registered cost" option for bidding commitment costs, under which a market participant can bid fixed costs for 30 days.

Cal-ISO now has roughly 35,000 MW of use-limited resources available. The goal is to commit these resources when they are of most value to the grid and at maximum profit for the generation owner.

The original language on commitment costs was altered to reflect comments made by CPUC Commissioner Mike Florio.

Florio's changes address concerns related to the use-limited status of preferred resources. This includes giving parties that might be affected—including investor-owned utilities, demand-response and energy-storage providers, and others—more time to better understand and manage the transition to the cost-bidding structure.

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures


Feeder #1
Percentage of Yearly Maximum MW
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1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
January
February
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August
September
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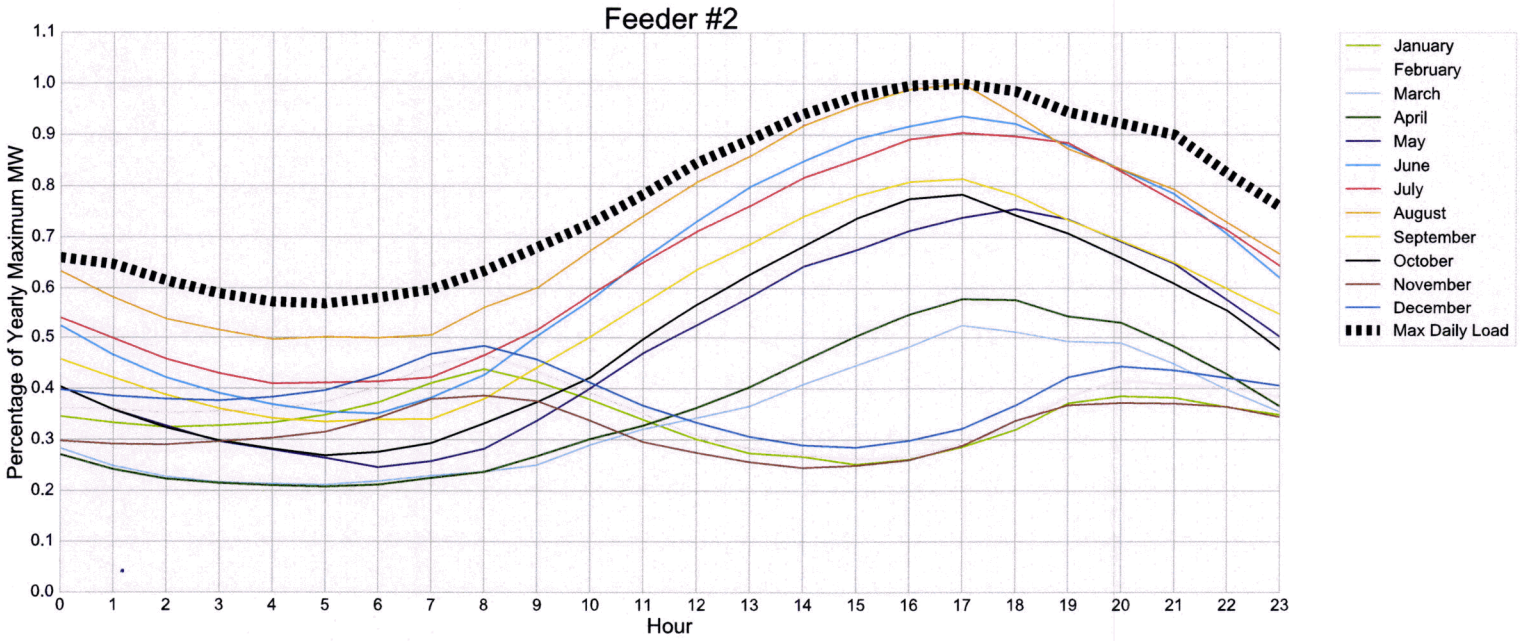
November
December
Max Daily Load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Percentage of Yearly Maximum MW
Hour
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1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
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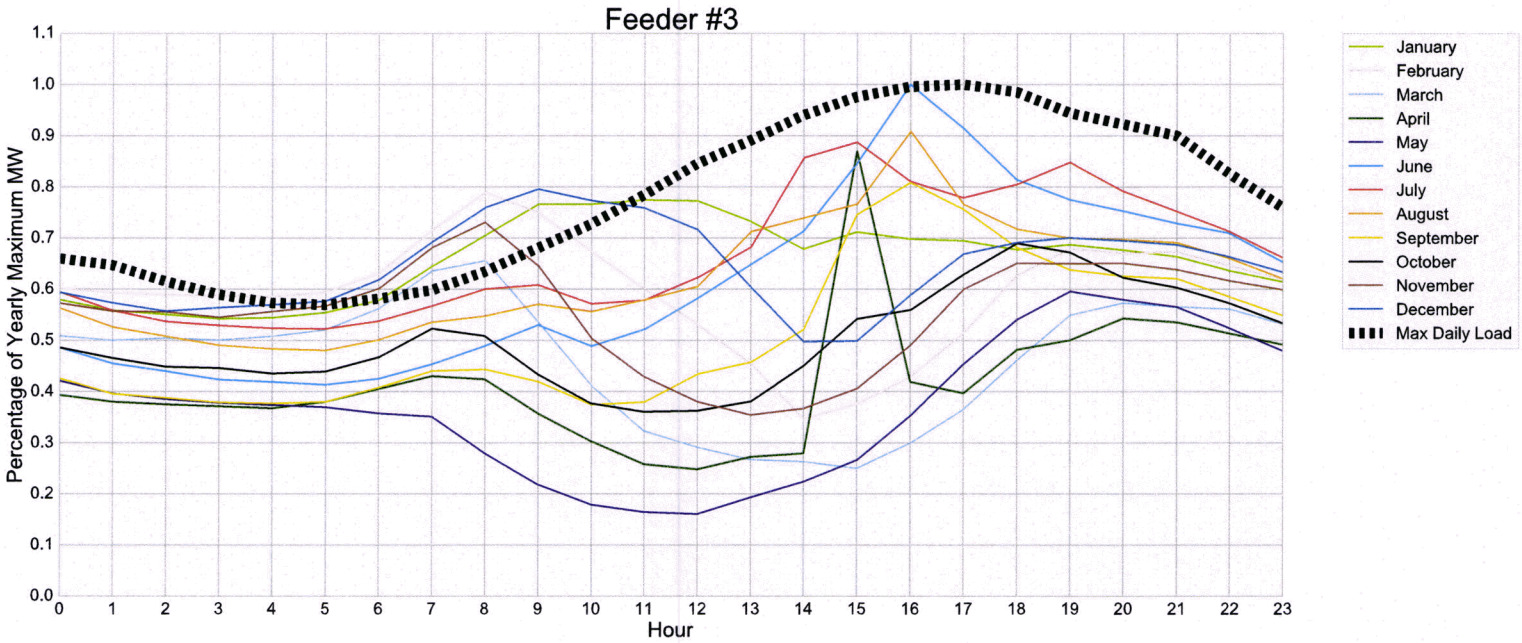
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Hour
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1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
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0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
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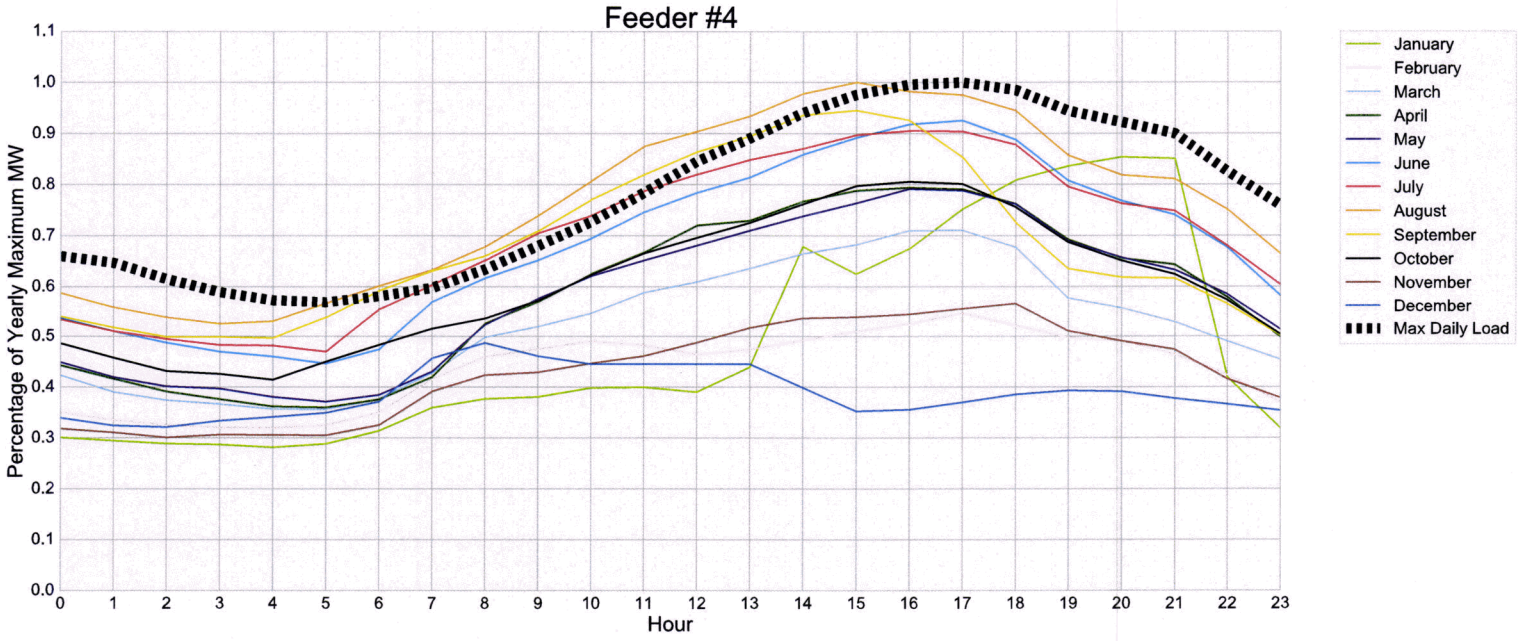
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Percentage of Yearly Maximum MW
Hour
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0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
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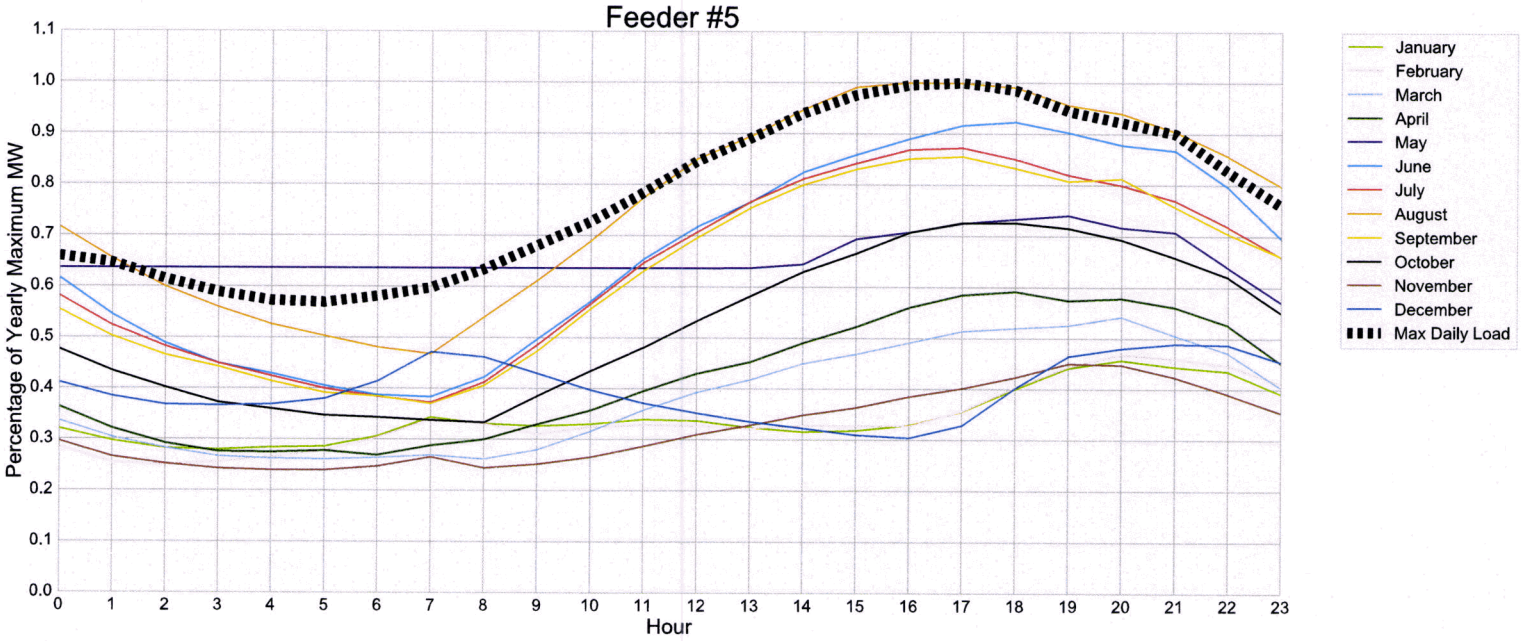
Max Daily Load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0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
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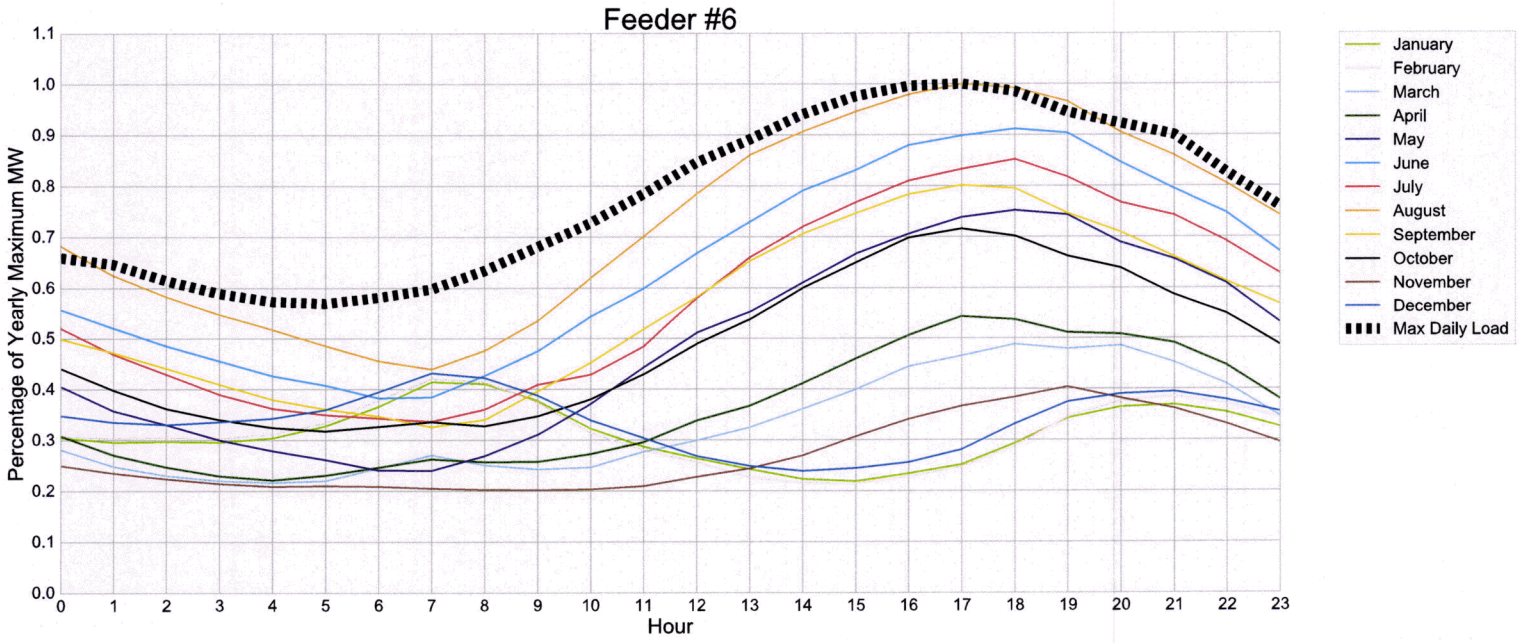
July
August
September
October
November
December
Max Daily Load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Percentage of Yearly Maximum MW
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0.3
0.2
0.1
0.0
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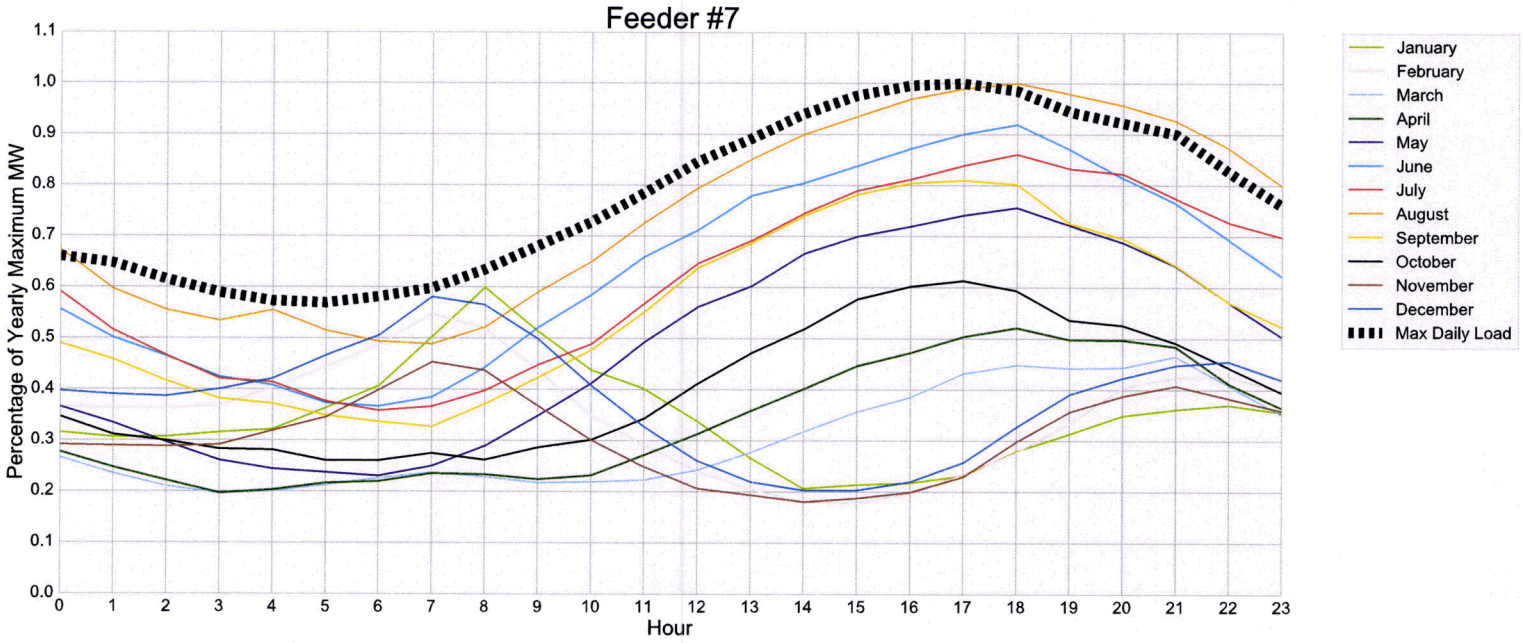
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Percentage of Yearly Maximum MW
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0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
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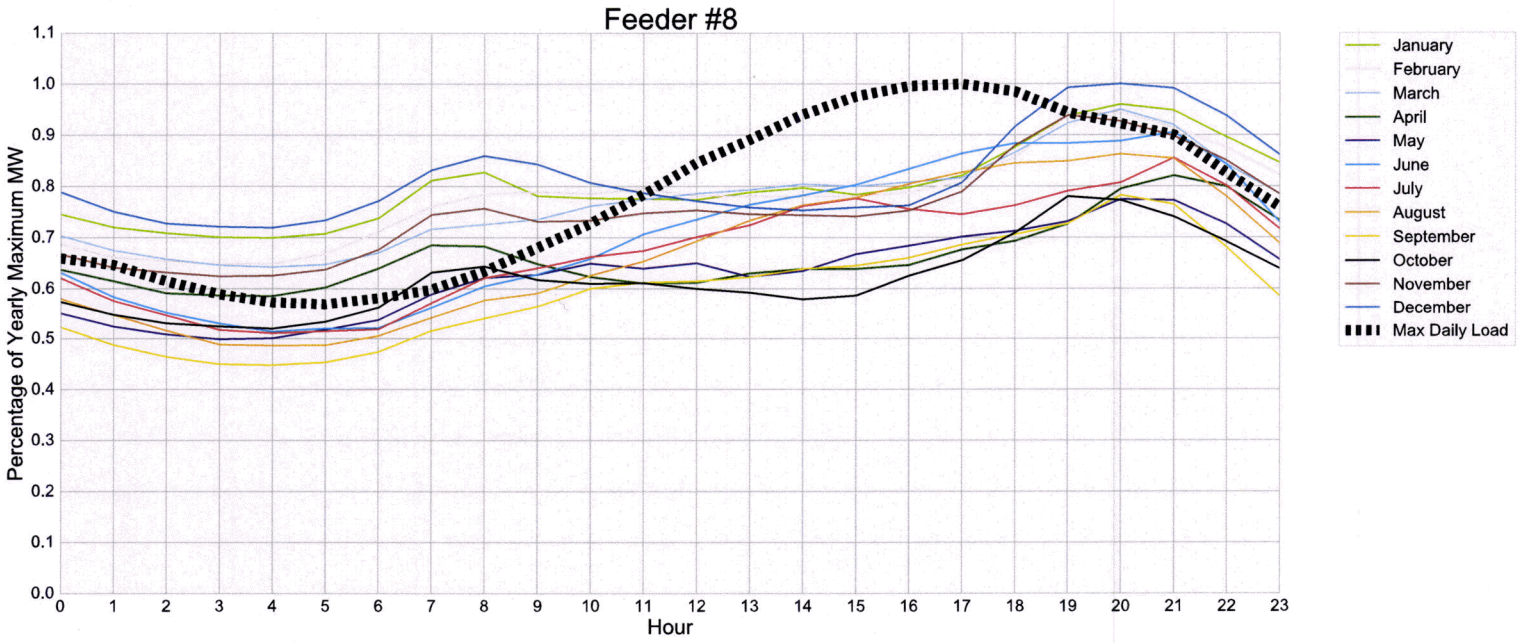
Feeder #8
Percentage of Yearly Maximum MW
Hour
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
January
February
March
April
May
June
July
August
September
October
November
December
Max Daily Load

Exhibit WAM-9: Excerpt from
PG&E 2014 General Rate Case Phase II Prepared Testimony,
Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate
Design, Application 13-04-012

Application: _____
(U 39 M)
Exhibit No.: (PG&E-1)
Date: April 18, 2013
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2014 GENERAL RATE CASE PHASE II

PREPARED TESTIMONY

EXHIBIT (PG&E-1)
VOLUME 1
REVENUE ALLOCATION AND RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REVENUE ALLOCATION PROPOSAL

F. Development of Marginal Cost Revenues

In this section, PG&E presents a description of the development of the marginal cost revenues used in PG&E's proposed EPMC allocation of the distribution and generation functional revenue. Marginal primary and secondary distribution capacity cost revenue and marginal customer access cost revenue are used to calculate EPMC factors and allocate distribution functional revenue. Marginal generation capacity and energy cost revenue are used to calculate EPMC factors and allocate generation functional revenue.

1. Distribution Marginal Cost Revenue

a. Demand-Related Distribution Marginal Cost Revenue

Demand-related distribution marginal costs are estimated for PG&E's primary distribution (between 60 kilovolts (kV) and 4 kV) and secondary distribution (below 4 kV) systems. PG&E uses the appropriate demand measure for each marginal cost to compute the marginal cost revenue. Specifically, PG&E estimates class loads at the substation level using weighting factors called "peak capacity allocation factors" (distribution PCAF)[7] and at the final line transformer (FLT) level.[8]

1) Primary Marginal Cost Revenue

PG&E uses division level distribution PCAF-weighted loads to estimate primary marginal cost revenue. For a given rate schedule and division, the recorded primary marginal cost revenue equals a three-year average of recorded division-level distribution PCAF loads multiplied by the estimated primary marginal cost and the

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7 Additional information on distribution PCAF loads used in the revenue allocation is provided with PG&E's revenue allocation workpapers. The substation-level PCAF-weighted loads are weather-normalized weighted loads that indicate what contribution a class has made to a substation's peak. These PCAF-weighted loads are then summarized by division for the calculation of primary demand-related marginal cost revenue.

8 Additional information on FLT loads is provided with PG&E's revenue allocation workpapers. FLT loads are either the class' diversified non-coincident demand at the FLT (residential and small commercial classes) or the class' undiversified non-coincident demand at the FLT (all other classes). Non-coincident demand is the class' highest observed demand during the year. As more than one residential or small commercial customer are served by a FLT, the FLT loads for these classes are scaled down (diversified) to reflect the fact that not all the customers served by that transformer will be operating at the time the FLT reaches its peak. For all the other classes, PG&E assumes that there is one customer per FLT.

Exhibit WAM-10: Excerpt from
California Public Utilities Commission, Decision15-08-005

ALJ/DUG/SCR/ek4 **Date of Issuance 8/18/2015**

Decision 15-08-005 August 13, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M).	Application 13-04-012 (Filed April 18, 2013)

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision adopts eight separate settlements as proposed by the settling parties and resolves the remaining outstanding issues based on the merits of the litigated positions. This completes the current review of Pacific Gas and Electric Company's (PG&E) electric marginal costs, revenue allocation, and rate design. Adoption of these new rates will reallocate the existing authorized revenue requirement amongst the various customer classes and within those customer classes. One settlement was partially contested and this decision resolves those contested issues primarily in accordance with the proposed settlements.

Because this proceeding deals with only rate design related questions and not operating or capital costs, or how PG&E operates its electric system, there are no changes to PG&E's overall authorized revenue requirement, although individual customer's bills may change as a result of changes in rate design. Also, there is no impact on employee, customer, or public safety, again because this decision does not change PG&E's revenue requirement or have any direct impact on electric operations.

This proceeding is closed.

1. Procedural History

The proceeding has a complex history, as parties sought and were granted numerous extensions of time to complete settlement negotiations with various sub-groups of interested parties which resulted in eight separate settlements covering all but a few issues that were litigated. All settlement rules were followed and all parties had notice and opportunity to participate. The

find that they contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds for its adoption; that the settlement was limited to the issues in this proceeding; and that the settlement included a comparison indicating the impact of the settlement in relation to the utility's application and contested issues raised by the interested parties in prepared testimony, or that would have been contested in a hearing. These two findings that the settlement complies with Rule 12.1(a), allow us to conclude, pursuant to Rule 12.1(d), that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Based upon our review of the settlement documents we find, pursuant to Rule 12.5, that the proposed settlements would not bind or otherwise impose a precedent in this or any future proceeding. We specifically note, therefore, that neither PG&E nor any party to any of the settlements may presume in any subsequent applications that the Commission would deem the outcome adopted herein to be presumed reasonable and it must, therefore, fully justify every request and ratemaking proposal without reference to, or reliance on, the adoption of these settlements.

7. Summary of Settlements

A copy of all eight of the Settlement Agreements, fully executed by all interested parties, are available at the links below following each settlement. The final language of the settlement controls the terms and conditions of the adopted rates except as specifically modified herein. The proposed settlements are as follows:

1. Settlement Agreement on Marginal Cost and Revenue Allocation Issues, filed July 16, 2014;

http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=99753189;

2. Residential Rate Design Supplemental Settlement Agreement, filed July 24, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=101125976;

3. Large Light and Power Rate Design Settlement Agreement, filed July 25, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=102226995;

4. Streetlight Rate Design Supplemental Settlement Agreement, filed August 29, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=103390568

5. Amended E-Credit Rate Design Supplemental Agreement, filed March 30, 2015;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=151726093;

6. Medium Commercial Rate Design Settlement Agreement, filed September 5, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=105647677;

7. Small Commercial Rate Design Settlement Agreement, filed September, 5, 2014; and

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=107147806

8. Agricultural Rate Design Settlement Agreement, filed December 2, 2014.

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=143515264.

Exhibit WAM-11: Excerpt from
California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

Pacific Gas and Electric Company
2014 General Rate Case Phase II, A.13-04-012

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION
Appendix A

Marginal Generation Energy Costs:

Table 1 - 2014 Marginal Generation Energy Costs by Time of Use (TOU) Rate Period and Voltage Level (¢/kWh)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	5.613	5.718	6.001
2	Summer Partial-Peak	4.791	4.881	5.123
3	Summer Off-Peak	3.654	3.722	3.907
4	Winter Partial-Peak	4.856	4.948	5.192
5	Winter Off-Peak	3.968	4.043	4.243
6	Annual Average	4.266	N.A.	N.A.

Marginal Transmission and Distribution Costs:

Table 2: 2014 Marginal Transmission Capacity Cost ($/kW-Yr)

Line No.	Transmission Capacity
1	34.86

Table 3: 2014 Distribution Marginal Customer Access Costs ($/Customer-Yr)

Line No.	Class	Marginal Customer Access Cost
1	Residential	73.72
2	Agricultural A	321.96
3	Agricultural B	1,457.43
4	Small L & P	323.37
5	A10 Medium L & P Secondary	638.43
6	A10 Medium L & P Primary	1,917.29
7	E19 Secondary	748.05
8	E19 Primary	6,288.92
9	E19 Transmission	6,650.02
10	E20 Secondary	5,559.77
11	E20 Primary	6,688.18
12	E20 Transmission	6,659.54
13	Streetlights	83.05
14	Traffic Control	105.91

Table 4: 2014 Marginal Distribution Capacity Costs by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Yr)	New Business on Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	95.45	12.31	4.00
2	De Anza	112.71	22.30	2.45
3	Diablo	52.57	20.78	4.01
4	East Bay	60.29	18.87	1.44
5	Fresno	30.31	8.05	1.61
6	Kern	31.43	7.95	1.97
7	Los Padres	40.87	9.75	2.03
8	Mission	19.87	9.90	1.81
9	North Bay	17.74	12.66	2.13
10	North Coast	42.22	12.65	3.13
11	North Valley	36.06	16.22	3.60
12	Peninsula	38.62	10.46	2.98
13	Sacramento	37.65	13.07	2.21
14	San Francisco	18.33	6.24	1.28
15	San Jose	38.50	12.18	2.79
16	Sierra	29.68	10.15	3.21
17	Stockton	38.26	8.85	2.30
18	Yosemite	45.78	17.54	2.94
19	System	37.33	11.26	2.33

Table 5: 2014 Marginal Distribution Capacity Costs by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	Carmel Valley 12kV	0.00	31.07	31.07	12.31	4.00
2	Central Coast	Gonzales	0.00	31.07	31.07	12.31	4.00
3	Central Coast	Hollister	16.07	31.07	47.14	12.31	4.00
4	Central Coast	King City	129.50	31.07	160.57	12.31	4.00
5	Central Coast	Monterey 21kV	0.00	31.07	31.07	12.31	4.00
6	Central Coast	Mty_4kV (Monterey Bk#1F	0.00	31.07	31.07	12.31	4.00
7	Central Coast	Oilfields	0.00	31.07	31.07	12.31	4.00
8	Central Coast	Prunedale	0.00	31.07	31.07	12.31	4.00
9	Central Coast	Pt Moretti	0.00	31.07	31.07	12.31	4.00
10	Central Coast	Salinas (4/12 kV)	33.73	31.07	64.80	12.31	4.00
11	Central Coast	Santa Cruz Area	0.00	31.07	31.07	12.31	4.00
12	Central Coast	Seaside 4kV	0.00	31.07	31.07	12.31	4.00
13	Central Coast	Seaside-Marina 12kV	60.75	31.07	91.82	12.31	4.00
14	Central Coast	Soledad	0.00	31.07	31.07	12.31	4.00
15	Central Coast	Watsonvlle (12/21kV)	277.75	31.07	308.82	12.31	4.00
16	Central Coast	Watsonvlle (4kV)	0.00	31.07	31.07	12.31	4.00
17	De Anza	Cupertino	0.00	15.15	15.15	22.30	2.45
18	De Anza	Los Altos (12 kV)	130.97	15.15	146.12	22.30	2.45
19	De Anza	Los Altos (4kV)	0.00	15.15	15.15	22.30	2.45
20	De Anza	Los Gatos	101.47	15.15	116.62	22.30	2.45
21	De Anza	Mountain View	70.62	15.15	85.77	22.30	2.45
22	De Anza	Sunnyvale	108.09	15.15	123.24	22.30	2.45
23	Diablo	Alhambra	0.00	28.54	28.54	20.78	4.01
24	Diablo	Brentwood	0.00	28.54	28.54	20.78	4.01
25	Diablo	Clayton / Willow Pass	0.00	28.54	28.54	20.78	4.01
26	Diablo	Concord	22.24	28.54	50.77	20.78	4.01
27	Diablo	Delta (Split Into Bw And Pitts)	0.00	28.54	28.54	20.78	4.01
28	Diablo	Pittsburg	18.00	28.54	46.54	20.78	4.01
29	Diablo	Walnut Creek 12 kV	24.79	28.54	53.32	20.78	4.01
30	Diablo	Walnut Creek 21 kV	30.60	28.54	59.14	20.78	4.01
31	East Bay	C-D-L	128.09	8.29	136.39	18.87	1.44
32	East Bay	Edes-J	0.00	8.29	8.29	18.87	1.44
33	East Bay	K-X	0.00	8.29	8.29	18.87	1.44
34	East Bay	North	0.00	8.29	8.29	18.87	1.44
35	East Bay	South	60.14	8.29	68.44	18.87	1.44

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	))))	DOCKET NO. E-00000J-14-0023

EXHIBIT
TEP-1
ADMITTED

Direct Testimony of

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

February 25, 2016

TABLE OF CONTENTS

I. Introduction.....1

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Exhibits:

Exhibit CT-1 Initial Comments filed in Docket NO. E-00000J-14-0023

I. Introduction.

Q. Please state your name and business address.

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85701

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Senior Director of Energy Supply for Tucson Electric Power Company ("TEP" or "the Company") and UNS Electric ("UNS Electric").

Q. Please describe your background and work experience.

A. I served in the United States Navy from 1984–1993 as a Nuclear Reactor Operator in Submarine Service. From 1993-1995, I worked as a Power Plant Operator for the Biosphere II Project in Oracle, Arizona.

I was hired by TEP in 1995 as a Power Plant Operator. In 1996, I moved into TEP's Wholesale Marketing Department where I held several positions in Energy Trading, Marketing, Project Management, and Scheduling before being promoted to Supervisor/Manager in 2003. From 2003-2008, I held supervisory positions in Trading, Scheduling, and Procurement before taking over Utility Scale Renewable Energy Development in 2008.

In 2010, I took over all aspects of renewable energy development for both TEP and UNS Electric, Inc. In my current position, I am responsible for the renewable resources and renewable resource programs for the Companies, including compliance with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff Rules ("REST Rules") (A.A.C. R14-2-1801 through R14-2-1818)). In 2013, I added

oversight of the Wholesale Marketing department to my duties, and in 2014 was promoted to Senior Director.

I received my Bachelor of Science in Business Management from the University of Phoenix in 2000 and Master of Business Administration from the University of Phoenix in 2002.

Q. What is the purpose of your Direct Testimony?

A. My testimony will focus on (i) TEP and UNSE's (collectively the "Companies") position regarding the value of distributed solar, (ii) methods on how to calculate that value, (iii) a comparison of DG solar to utility-scale solar, and (iv) specific issues raised by Commissioners through docketed letters.

Q. What do the Companies hope to see as an outcome of this Value of Solar (VOS) docket?

A. The Companies would like to see a clear definition and resolution to the following issues:

1. Clearly separating the utility's cost of service from any societal and forward looking benefits that the Commission deems are appropriate.
2. Identify the necessary revenue streams to fairly compensate both the utility and the customer.
3. Establish an appropriate mechanism or model that provides the correct price signals to allow the market to respond to customer needs and supports the advancement and adoption of new technologies.

Q. Do the Companies have some general thoughts on the costs and benefits of distributed generation?

A. Yes. We submitted initial comments in this docket in February of 2014. Those comments provided an overview of the costs and benefits in the context of rate making and providing economical service to our customers. A copy of those comments are attached as **Exhibit CT-1**.

II. <u>Companies' Current Rate Case Proposals.</u>

Q. Does either TEP or UNSE have a proposal before the Commission specifically related to the value of a customer's distributed generation ("DG") facility?

A. Yes. Both companies have submitted proposals to make changes to the current net energy metering ("NEM") rules in their respective rate cases. The proposed changes to the Net Metering tariff are two-fold:

1. A request for a new net metering tariff that provides monthly bill credits at a Renewable Credit Rate ("RCR") for excess energy produced and pushed onto the grid from a customer's solar system. The RCR is equivalent to the most recent utility scale renewable energy purchased power agreement connected to either of the Companies' distribution system.

2. A partial waiver of the Net Metering Rules to eliminate the "roll over" of excess generation to offset future usage, as is currently prescribed in A.A.C. R14-2-2306.

Q. What is the basis for the Companies' proposed NEM changes?

A. The current NEM rules and policies were established to provide an incentive to customers in the early years of renewable energy development, particularly solar DG due to its initial high costs. However, the rapid technological advancement of solar and

subsequent decline of prices, as well as the availability of generous federal tax credits for solar DG systems, have led to a dramatic increase in DG solar installations. While the technology has advanced and prices have declined, the various rate subsidies (including NEM) have not been addressed. This has led to a disconnect between the appropriate price signals for the market and technology adoption; a significant cost shift from solar customers to non-solar customers due to antiquated rate design structures; and design inefficiencies resulting in the promotion of more expensive technologies.

Specifically, retail NEM programs and policies do not promote the adoption of DG in the most cost-effective manner, which has led to the installation of systems that are designed to result in the maximum annual production to offset charges for kWh consumption from the utility's system rather than promote demand reduction and system-wide benefits. Additionally, the Company believes that it is no longer appropriate to pay full retail credit for DG solar when a utility-scale solar facility on the same distribution system can be built or purchased for approximately half the cost and that provides the same green energy with the same environmental attributes. The benefits and value of utility-scale solar production on the distribution system is nearly identical to DG. When considering the potential for increased production and lower costs, it can be argued that these benefits are superior to DG. And while utility-scale developers have consistently lowered their costs to reflect the maturity of the industry and advancement of solar development, and have passed those savings on to utilities and customers, the solar DG industry has fought to preserve full retail net metering. The Company's position on this issue has been consistent. *A solar DG customer who pushes energy back onto the grid should be compensated at the wholesale rate for solar energy.*

The second component of the Company's proposal is to eliminate the month to month banking of retail energy credits. This policy, along with a full retail rate credit for excess

generation, drives many solar providers to design DG systems to produce as much energy as possible in the non-summer months in order to "get through" the summer months without having to pay for the energy generated and delivered by the utility that was consumed by the customer. The value of energy produced by a solar system between October and May ***is not*** equivalent to the energy consumed by the customer during the summer peak demand months of June through September.

Q. Are the Companies proposing that the above changes to NEM be included in a VOS calculation?

A. Not necessarily. If the Commission wants to address all of the issues regarding the value of solar and would like to assign individual values to societal and economic benefits, then it will require more than a simple change to NEM policies. The Companies' NEM proposals only address a portion of the value of solar as it relates to current rate design structures, pricing signals, and excess energy under the traditional cost of service rate structure. If simplicity is the goal in evaluating DG and its benefits, then choosing the Companies' proposed use of wholesale market price of solar transactions as the "value" is an easily attainable, reasonable and objective proxy.

However, if the Commission decides to value solar relative to known and measurable quantities of variable cost savings (rate design principles), along with providing monetary consideration for forward looking and societal benefits (resource planning principles), then it will require a more comprehensive valuation model.

III. The Companies' Responses to Chairman Little's December 22, 2015 Letter, Commissioner Burns' February 8, 2016 letter, and Commissioner Stump's February 19, 2016 letter.

Q. Chairman Little's letter indicates that this docket should seek to develop a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Do the Companies have a recommendation for a more comprehensive VOS model?

A. Yes. The Companies propose using a model similar to the one being developed by the Utah Public Service Commission (Docket No. 14-035-114). This model effectively uses two cost of service models to determine the real impact to rates under the cost of service model, and then allows the Commission to address forward looking and resource planning components separately.

Q. Please describe the Utah model in more detail.

A. Utah is developing a model that consists of two components:

1. Known and measurable costs and benefits currently collected through rates (rate setting process)
    a. Fuel offset/avoided energy
    b. Losses (energy/line)
    c. Administration and integration costs
    d. Ancillary services
2. External, societal, and future benefits for which a separate revenue stream must be identified (resource planning process)
    a. Avoided generation capacity
    b. Avoided transmission & distribution capacity
    c. Avoided emission costs (CO2, SO2, NOX, etc.)

d. Fuel hedging costs/savings

e. Additional costs associated with operational compliance – integration costs

f. Societal benefits

This model uses two cost of service studies: a Counter factual Cost of Service Study ("CFCOS") that assumes away the existence of NEM customers' power generation (where the Company supplies all customer load as if there was no solar DG); and an Actual Cost of Service Study ("ACOS"), which shows actual cost of service inclusive of existing NEM customers (meaning the Company supplies only the "net" load of a DG customer). This allows the Commission to determine if there is a cost or benefit that should be applied to the DG customer based on known and measurable costs and benefits currently collected through rates.

Additionally, this model then defines the more subjective costs and savings associated with external, societal, and future benefits for which a separate revenue stream must be identified. The Commission would have the opportunity and flexibility to set these additional cost and savings values at their discretion in the Company's rate case, based on data provided through the Company's Integrated Resource Plan, Stakeholder input, and other factors. Cumulatively, these two values would provide the basis for compensation for the DG solar customer.

Q. What are some of the other considerations and assumptions made in the model described above?

A. There were several considerations and assumptions made in the Utah process that include:

1. The respective utility has all necessary meter data to provide meaningful data.

2. Using multiple COS studies would provide impacts of NEM at system, state, and customer levels.

3. The Counter factual and Actual Cost of Service studies should be commensurate with a test year, which is consistent with the ratemaking concept of utilizing short-term study periods (test year) because they would be, in effect, used to set rates.

4. Actual COS would capture cost impacts associated with excess energy.

5. Excess energy does not have price or value assigned to it in ACOS, other than as recognized in net power cost analysis.

6. Segregates NEM and non-NEM customers into two classes for purposes of determining cost allocation based on their respective usage characteristics, solving cost causation and mitigating subsidization.

7. Does not establish a new rate class, only segregates them for purposes of analysis

Q. How would variations of cost and value based on locational and production benefits be accounted for?

A. The utilization of appropriate rate design structures, including TOU pricing, will compensate for production benefits. Locational benefits and costs within a distribution system may be able to be identified through the use of more detailed system modeling; however, at this time the Company believes it is unnecessary to develop such a complex valuation model.

Q. How were the value and cost of solar considered in the development of the current net metering tariffs?

A. Due to a lack of quantifiable costs and benefits at the time the current tariffs were created nearly a decade ago, and a political desire to implement more renewable generation through NEM policies, the concept of retail net metering was used for its ease of

implementation. Indeed, the Commission order directing the preparation of the net metering rules expressly stated that "Net metering provides a financial incentive to encourage the installation of DG, especially renewable resources." Decision No. 69877 (August 28, 2007). This concept was often referred to as a "rough justice" based on current solar prices, actual cost savings, and unquantifiable societal and resource planning benefits.

Q. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?

A. Yes. As the cost of panels and installed systems came down, the Commission lowered the ratepayer-funded up-front and performance-based incentive payments in an attempt to coincide with the cost reduction. Eventually the ratepayer-funded up-front and performance-based incentive payments were reduced to zero. With continuing decreases in equipment and installation costs and the remaining Federal and State tax incentives, which are fixed, the cost/benefit ratio continues to improve for the individual customer (purchased system) and the leasing entities (leased system). Unfortunately, due to the current structure of NEM (and current rate design), this is also increasing the cost burden on non-DG customers.

Q. Is it appropriate to factor the cost of panels into the reimbursement rate for net metering? If so, how?

A. No. A customer's choice to invest in solar should be evaluated using the same economic premise as a non-renewable generator (such as a gas generator), or other energy efficiency measures (cost of a more efficient air conditioner or heater, upgraded windows, etc.). In short, the cost of the measure should be applied to the expected savings and whether or not the purchase makes economic sense.

The issue is not in the procurement of the system, but in the economic signals sent to the customer through the determination of its value. There should be no more basis for reimbursing the cost of the panels than reimbursing a customer for a gas generator to off-set a demand charge.

Q. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?

A. There are good arguments to the locational value of both utility-scale solar and DG solar, and this value will be more easily defined as penetration levels continue to rise. However, this type of granularity is overly complex, subject to variability and difficult to establish at this time. The infrastructure necessary to establish locational pricing inside a distribution system is several years away, and does not represent the most cost-effective use of the utilities' capital.

Additionally, other aspects of locational pricing must be considered. Questions such as: a.) whether the locational pricing will be based on real-time flows and constantly changing for all customers; b.) whether a customer's pricing will be fixed for a period of time depending on their position in the queue; c.) if pricing is to be fixed for a period, how long and how often is it to be reevaluated; d.) if pricing becomes negative, will that cost be shared by existing DG customers; e.) if upgrades are required to a feeder or substation due to excessive DG, will those costs be borne by those users or all users?

Q. How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?

A. Cost and value are specific to the entity in question. For example, it is well known that a traditional unshaded, southern facing system with a 20-32 degree tilt (located in TEP's service territory) will have the highest annual production of kWh. As a result, the value to the customer is highest; however, the value to the utility is diminished because that system provides fewer grid benefits than systems of other orientations - for example, it does not generate as much electricity later in the afternoon when demand on the system is higher. The cost of the systems will be approximately the same; but the "value" varies based on specifications unique to each installation and perspective.

A western facing panel provides greater production during summer peaking hours, but at an economic impact to the customer based on current rates and NEM policies. The Commission must determine whose value they are going to consider – the individual customer who purchased the system, the utility looking to reduce their overall system costs, or society in general who wants lower rate impacts with increasing renewable energy?

Solar panels that track the sun's movement increase production but at an added expense – such systems are traditionally not cost-effective on small DG systems. Increased production and lower variability would be reflected in the increased compensation if a "per kWh" method is still employed. Ultimately, time of use pricing would be the most accurate reflection of production and would capture this increased production and efficiency.

Q. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?

A. Yes, the deployment of storage should be encouraged. Depending on the particular rate design currently in effect, storage can be used to significantly reduce a customer's peak demand on the grid, thereby reducing the utilities' need for peaking resources (assuming the DG storage reached a "critical mass" quantity that could provide overall system benefits). However, as with most technologies, storage and the ability to provide additional system value (such as reduction in peak generation needs or ancillary services) will be achieved more cost-effectively through large scale storage.

Q. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?

A. Economies of scale result in utility-scale or community-scale solar having a 25%-40% reduction in installed price over rooftop solar, even when factoring in other costs such as land and increased interconnection costs.

While the Companies do not have significant wind portfolios, nor do they have any ownership in wind facilities, it is the Companies' understanding that the installed price of wind is less than half of DG solar. However, there is an inherent value in the reduction in losses associated with locally sited solar, while wind resources typically require high voltage transmission to get the resource to the load. There is additional value associated with higher capacity values and increased production from wind that are not associated with solar; however, much of the wind generation is during non-peak hours. It is generally prudent to have an appropriate mix of wind and solar generation that can complement each other while minimizing resource risk.

At this time, the Companies do not believe it is appropriate to compare energy efficiency to DG solar, as it is to some degree an "apples to oranges" comparison. The majority of their similarity lies in the fact that they both reduce kWh production from conventional fuels. Beyond that, many differences between these resources exist.

Q. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

A. Although the Companies do not see the need to apply an "intermittency factor," they believe that the cost associated with solar intermittency would be reflected using appropriate values and costs. Acknowledging certain characteristics of DG solar and DG customers would sufficiently account for those values and costs, such as the specific demand rates associated with needing to provide full back up services, ancillary charges to reflect the need to maintain or provide voltage and frequency control (which could then be alleviated should a customer self-provide).

As of today, storage is the only technology that reduces the intermittency of solar. However, there are long-term reliability concerns that should be considered. If customer-owned distributed storage technologies were to be implemented and the grid became reliant on them to prevent intermittency, the customer would have to be relied upon to replace or repair the storage technology if it stopped working. Forecasting programs may assist in short-term planning or recognizing pending generation changes, but it does not change or reduce the intermittency.

Q. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

A. DG solar production relative to, and coincident with, peak demand should be looked at two ways: coincidence during annual system peak (summer), which is relative for planning purposes; and coincidence during daily system peak, which is relative to short-term operations.

Relative to the Companies' annual system peak, DG solar has a coincident peak of approximately 30% during the peak hour (which is typically between 4:00 pm – 5:00 pm). While some would argue that this represents a 30% capacity value to the utility, it should be noted that 2 hours after the system peak the Companies' hourly load is still between 90%-93% of the system peak and the solar value is effectively zero. This is an important concept when discussing capacity value and coincident peak production and demand.

With regards to production versus system peak throughout the year, there is no seasonal system peak that coincides when DG solar produces it maximum value at noon. The closest seasonal system peak that would be coincident with DG solar is that of late spring or early fall where the Company has little to no air conditioning or heating load, and there are no defined morning or evening peaks. During this time, system loads tend to rise from morning until afternoon and stay relatively flat until early evening. Unfortunately, these are some of the lowest system peak loads of the year, when there is an abundance of excess generation available and power and gas prices tend to be their lowest. Subsequently, the value of solar during these times is greatly diminished.

During winter peaking months, the Companies experience peak periods in the morning before the sun rises and in the evening after the sun sets. For obvious reasons, the value of solar during the winter is significantly reduced as the generation during the day only serves to offset incremental fuel expense and has zero value relative to capacity.

Although the value of solar relative to the Companies' load varies, these factors can be addressed through appropriate valuation in the cost of service and resource planning process with the appropriate price signals being reflected in the weighted average value.

Q. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

A. Yes, it is possible for DG solar to be more dispatchable; however, currently it is not practical. The ability for DG solar to be more dispatchable relies on the concept of smart inverters and the ability of the inverter to receive a signal from the utility to respond to set point changes. There are; however, limitations to DG solar dispatchability. For instance, the utility cannot send a "regulation up" signal to provide more energy, as a DG solar system will always produce its maximum value. Even if the utility were to send a curtailment signal – or "regulation down" – the Companies have no idea what the systems' available generation capacity would then be. This is an issue with all intermittent generation resources.

Smart inverters would be able to vary set points to change VAR output of the inverters. This could be useful for distribution system reliability and stability requirements but requires a feeder level control system to manage the appropriate amounts. This also decreases the amount of energy that the system can provide while it is producing VARs. This inability to provide reliable regulation service obviously reduces or diminishes the value of solar relative to a grid operators' ability to manage grid resources. While

traditional electric service rates (bundled electric rate) includes these services, they should not be included in the value of solar.

Q. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How would the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?

A. The bi-directional flow of energy associated with DG solar will require modifications and upgrades to the distribution system. As it is a newly identified phenomenon, the Companies do not have specific measures in place to address any adverse effects as a result of reverse power flow. The bi-directional energy flow on the electrical distribution system varies based on many system electrical parameters that are created by the location and size of the solar system. The problems that are created with bi-directional flows also vary by the time of day and seasonality.

Additional measuring and monitoring equipment will be needed. New methods of modeling the distribution system will need to be developed to model and predict the impacts of a reverse power condition. Upgrades in system automation will be needed to phase balance transformer connections for load and for distributed generation. As reverse power affects the feeder power factor, the placement and sizing of switched distribution capacitor banks is affected as well as distribution transformer sizing. Distribution transformers are specifically designed for stepping down the voltage. Using them to step up the voltage (reverse power flow), unless specified to do so, is not a recommended practice by the manufacturers.

Although the value of solar relative to the Company's load varies, these factors can be addressed through appropriate valuation in the cost of service and resource planning process with the appropriate price signals being reflected in the weighted average value. The amount of remedies that will need to be made are dependent on the size and location of the DG solar installations.

The locational value of DG solar is more easily defined as penetration levels continue to rise. However, this type of granularity would be overly complex and difficult to establish at this time. The needed infrastructure necessary to establish locational pricing inside a distribution system is at least several years away, and does not represent the most cost-effective use of the Companies' capital during this transitional period. Additionally, as previously noted, other aspects of locational pricing must be considered. Questions such as: a) whether the locational pricing will be based on real-time flows and constantly changing for all customers; b) whether a customers' pricing will be fixed for a period of time depending on their position in the queue; c) if pricing is to be fixed for a period, how long and how often is it to be reevaluated; d) if pricing becomes negative, will that cost be shared by existing DG customers; and e) if upgrades are required to a feeder or substation due to excessive DG, will those costs be borne by those users or all users?

Q. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

A. The Utah model previously discussed allows for the Commission to set values for societal benefits, secondary economic impacts, and other subjective benefits. However, these values are difficult to quantify, and it is unlikely that the parties in this proceeding can do much more than agree that they exist. The Companies are not opposed to the

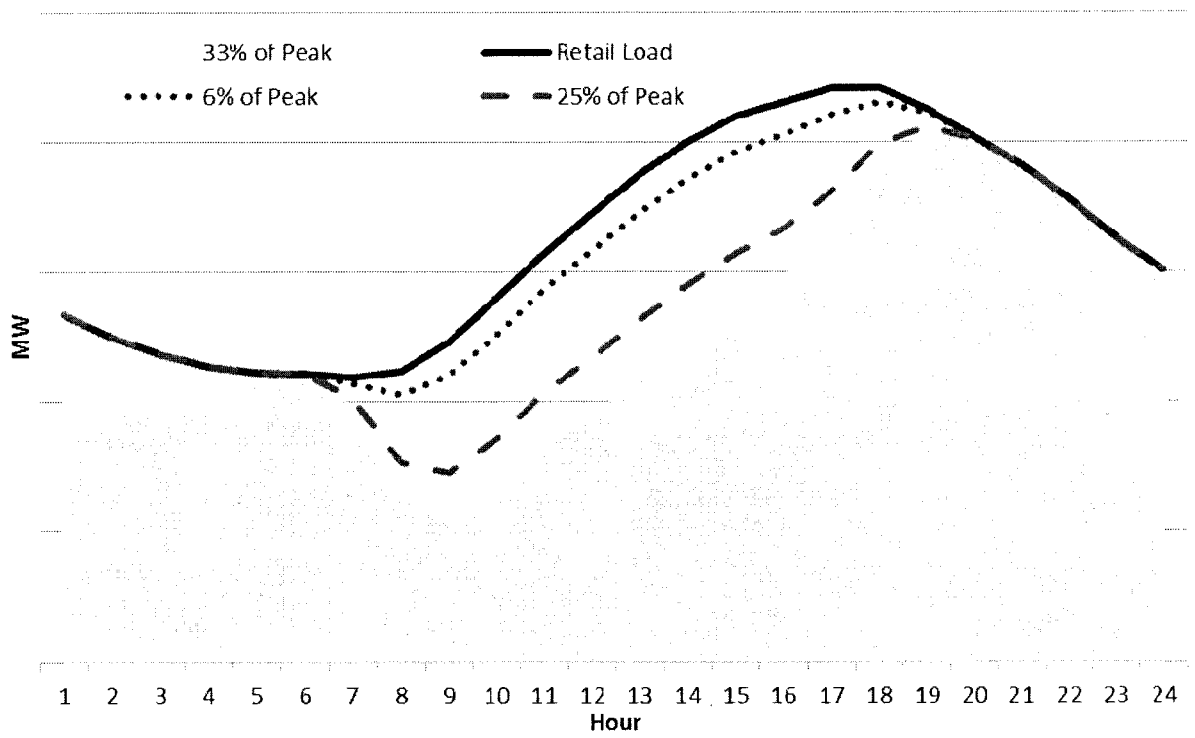
Commission adopting some form of value associated with those benefits, but it questions whether or not this value should be addressed through electric rate design, as current regulatory theory requires costs (and credits) to be based on known and measurable amounts. Instead, it may be more appropriate for State and local governments to provide an economic value or incentive to consumers through some form of tax benefit since society at large receives the greatest benefit from secondary economic impacts.

However, as already stated, this particular model does allow for the determination of societal and secondary benefits values. Should the Commission determine that there is a quantifiable benefit and that individual entities should be compensated through a rate structure, they would also need to determine how the additional revenue needed would be collected and disbursed (to the extent that it is not a direct offset to the current cost of service models with revenues collected through rates).

Q. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

A. The value and cost of DG solar is estimated to change with increased penetration. To determine the value of DG solar, it is imperative to understand its relationship to consumer load. Presumably, most DG solar is sited 'behind the meter' or on customer facilities. The relationship of a DG solar installation at a residential site is assumed to be different than an installation at a commercial site. We can assume that most residential peak load occurs soon after consumers arrive home from work. Commercial peak tends to occur during business hours. This is an important distinction in this discussion because the costs and value impacts to individual feeders and sub-transmission stations can vary due to the blend of residential and commercial customers. This discussion will refer only to the impact on the system in its entirety.

The chart below is a representation of a typical summer load graph and the impacts of increasing DG at various percentages of peak load and the diminishing value of solar as penetration rises.



Historically, electric utilities with predominant air conditioning load set a system peak demand between 4:00 to 5:00 PM on a summer day. DG solar can help reduce this peak but not at the full potential of the DG solar output. DG solar peak production is typically at 12:00 to 1:00 PM. The chart below demonstrates that at 6% (DG installation as a percent of peak retail demand) capacity addition there's an observable reduction of retail peak demand. With increasing DG solar penetration, there's also an observable shift in the load shape. Note the shift between the 6% case and the 25% case. Though there is a noticeable reduction in peak, the time the peak is set is shifting closer to the last diurnal hour of a typical clear-sky summer day (7:00 to 8:00 PM). It is significant then to note that though we introduce a 33% case, the reduction to the newly shifted 7:00 PM peak is

minimal. As retail load grows, DG solar will not contribute to the reduction of peak demand beyond 7:00 PM regardless of its penetration.

While it can be argued that DG solar may contribute to reduced losses, to apportioned capacity reductions (generation and transmission), and carbon emission reductions among other benefits, we note from the chart below that other challenges arise. As the sun is rising, electric load stabilizes and begins an ascent toward the peak. However, increased penetration of DG solar creates a rapid net drop in system load. It is at this point that the net reduction in load can create the need for rapid responding generators to regulate the initial steep decline in load followed by an immediate rise. From a resource planning context, with the increasing penetration of solar systems, we must take into consideration the right combination of resources to respond to the variability and intermittency of renewable systems.

Q. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

A. Fuel cost savings are calculated through the production models, which takes into account the weighted average of expected fuel savings per MWh based on the specific technology production profile. In the absence of a real time locational margin pricing ("LMP") mechanism, which is far too complicated to implement at this time, it would be best to reset the fuel rate with each rate case and allow for the recovery of this fuel rate expenditure through the Company's purchased power and fuel ("PPFAC") surcharge. While not as accurate as real-time pricing, it would at least be representative of the average fuel costs, with any under or over collections being applied to the PPFAC, leaving the Company revenue neutral.

Q. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?

A. If, in fact, DG solar capacity could be relied on dependably (through the use of storage, fuel cells or other similar technology), then it is possible that transmission capacity may be deferred. System growth can dictate the need for upgrades to the transmission system. Scenarios of high DG solar penetration can also result in transmission line capacity deferrals. Peak retail demand typically occurs in the summer months from between 4:00 PM and 5:00 PM. Peak DG solar production occurs during the noon hours of the summer months. The impact of increased DG solar not only reduces peak demand, it consequently also shifts the peak to the later evening hours. The peak shifts ultimately to the last diurnal hour when DG solar is no longer contributing to peak reduction. As DG solar penetration increases, its impact/reduction on peak minimizes; alternatively stated, the capacity value of DG solar diminishes with increased penetration.

DG solar can only defer transmission capacity upgrades in the near-term. As explained above and in question 16, high DG solar penetration shifts the peak. Ultimately, transmission systems are expanded to help serve the growing load and demand; a shifted demand that a high penetration of DG solar can't contribute to. Assigning a capacity value to a potential forward looking capacity deferral is a policy decision that the Commission will need to decide. As "future" benefits are captured in rates, not only would this value need to be determined, but a revenue stream would need to be identified to compensate DG solar customers.

Q. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?

A. In certain circumstances, extra capacity additions for the distribution system may not be necessary if the same scenarios for DG solar occur every day, i.e. DG is on and producing between 3:30 PM and 6:00 PM as TEP's circuit-peaks occur during these times. TEP's circuit peaks take into account or reflect any DG that is on at the time of our circuit's peaks. However, an overload may not automatically justify a new capital project. TEP will look at the number of hours a circuit is overloaded in a summer, consecutive hours it's overloaded, and what sections of overhead or underground are being pushed to their limits. Underground cable will be given more consideration (of being overloaded than overhead wire) since the costs to replace underground cable in melted duct work can be four times as expensive to replace. Overhead conductor will not be replaced until the overloads are reducing the life expectancy of the wire.

Q. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?

A. Yes, the grid provides value to DG solar. However, the inability to place a value on the service it provides – which is arguably immeasurable – is one of reasons a cost-of-service model is utilized for setting rates. This concept is one of the reasons the Companies take issue with not only net metering, but the idea of calculating a "value of solar" relative to the services the grid provides. It is expected that the utility provide safe, affordable, reliable, and increasingly cleaner electric service to all entities within its service territory based on actual cost-of-service, while we attempt to determine the "value of solar" above and beyond the cost-of-service benefits it offsets.

The grid itself, providing all of the required services necessary to support the customer's choice to install DG solar, is a critical component of DG solar. Utilities often mention that the grid provides all of the necessary ancillary services to compensate for DG solar's inability to self-provide (see earlier discussion), but what does that mean to the customer? What is the value to the customer of providing the necessary frequency and voltage support for the customers' electronics and appliances to operate properly? What is the value to the customer of providing the instantaneous back up generation necessary to prevent supply disruptions to the customer? What is the value to the customer of providing the necessary starting current to allow a customers' air conditioning system to run in the summer?

There are several reasons utilities and commissions around the country have established cost of service models for electric service, not the least of which is the inherent inability to place a value on such a necessary service. Any attempt to monetize the value of an essential service such as electricity, and the grid that provides that service, will ultimately produce "winners and losers". In its basic form as a support system for DG solar, the grid can be considered the "world's largest battery," providing all the same services as a customer-sited storage unit. Is the utility to be paid as a "storage facility" based on its value, or based on its cost of service? Since DG solar does not work without either the grid providing these services, or a self-contained storage facility allowing the customer to operate off-grid, wouldn't it be reasonable for the utility be paid the incremental savings a customer doesn't have to pay to go off-grid? Isn't that the equivalent value of the grid to the customer?

Inherently there is no fair mechanism for determining the value of the grid, as each customers' quality of life depends on its availability and reliability. The grid's benefit to

DG solar is undeniable, and should be both acknowledged and accounted for within a value of solar rate.

Q. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?

A. Yes. Each MWh of production from renewable energy reduces the amount of water consumed through the production of electricity from conventional generation. This value could be accounted for in several ways. If the Commission were to adopt the wholesale rate for an equivalent value of solar, the cost of water would already be accounted for in the equivalent wholesale rate. Under the more complicated methodology that the Utah Commission has adopted and was previously described, this cost savings would show up in the cost of service models as a difference in the cost to serve. From a broader societal perspective, especially in arid climates such as Arizona, it can be argued that the value of water savings exceeds the cost of the avoided water usage. However, this value is again difficult to establish, and may be more appropriate to address through State and local tax policies affecting renewable energy resources.

Q. Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?

A. No. Unless the solar DG is part of an established micro grid, that is grid-connected and part of the established regional recovery plan, there is no value relative to disaster recovery or backup service.

Q. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

A. DG solar installations are a growing percentage of generation supplying TEP's Balancing Authority ("BA") load but without the corresponding ancillary services. Ancillary services include Scheduling, Voltage Support, Regulation, Frequency Response, Imbalance, and Reserves. In the case of DG, Scheduling and Imbalance do not apply. Voltage Support, Regulation, Frequency Response, and Reserves by default are being supplied by the host BA.

Having an adequate supply of reserves is the key to being able to provide regulation and frequency response. Between BAs and Independent Power Producers the reserve quota is a function of generation. To date, this reserve responsibility has not been shared by the DG supplier.

Frequency response to disturbances is primarily provided by governor action on generators. Inverters on solar and battery storage systems can also provide frequency response but only if the inverter is not already at full output. In order for TEP to meet the new NERC frequency response standard (BAL-003), TEP carries spinning reserve that is distributed among its generating assets for governor action, and has contracted with battery storage service providers for inverter provided frequency response.

Voltage Support and VAR response between BAs is generally the responsibility of the host BA. Generating assets of another BA that reside within the host area are charged for the Voltage Support ancillary unless it can be self-provided. In the case of DG, this could work either way. Either TEP provides the reactive resources, or the DG inverters could be programmed for VAR response.

To date, DG solar has not been required to either pay for or self-provide these services. As a starting point for discussion on the appropriate charges for these services, the Companies would recommend using currently approved FERC tariff rates, at least for regulation, frequency response, and reserves which is required at the BA level. The customer could chose to self-provide VAR support, or pay the utility to provide.

Q. Do you have any additional comments with regards to the questions posed by the Commissioners?

A. Yes. The Companies appreciate the opportunity to address the Commissioners' questions regarding the most appropriate methods for evaluating and valuing DG. In addition to the testimony submitted here, Mr. Ed Overcast has filed comprehensive testimony that is more technical in nature and addresses other questions posed by the Commissioners.

Q. Does this conclude your testimony?

A. Yes.

Exhibit CT - 1

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February 14, 2014

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Arizona Corporation Commission
DOCKETED
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RE: Inquiries re: Value and Cost of Distributed Generation
Docket No. E-00000J-14-0023

Dear Mr. Olea:

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE") (jointly, the "Companies") hereby submit these joint comments in response to your Jan. 27, 2014 letter regarding the discussion of distributed generation ("DG") in Docket No. E-00000J-14-0023.

The Companies appreciate the Commission's interest in reviewing information regarding the costs and benefits of DG. Many public speakers and Interveners in Docket No. E-01345A-13-0248 offered broad, largely unsubstantiated claims about DG benefits as they argued against net metering changes proposed by Arizona Public Service Company ("APS"). The comments often failed to reflect ratemaking principles, the regulatory compact and the true costs that utilities incur to provide safe, reliable service to customers. This docket offers an opportunity to assess the quantifiable benefits that can be attributed to DG in a ratemaking context while also detailing DG costs and complications that can contribute to cost shifts and/or higher rates for utility customers.

Relevance and Significance of Potential DG Costs and Benefits

The relevance and significance of potential DG costs and benefits depends on the context in which they are considered. While rooftop photovoltaic ("PV") arrays and other DG systems create numerous impacts for their owners and the community at large, only some of these costs and benefits are relevant from a ratemaking perspective. Utility rates reflect only known and measurable service costs, not speculative future expenses, projected savings or broad societal impacts. To maintain consistency with ratemaking principles, the Commission should focus on DG costs and benefits that directly affect regulated utility rates and the cost of providing safe, reliable service. Just as utility rates do not reflect the comprehensive societal "value" of reliable grid power, they should not subsidize DG based on speculative economic and environmental benefits that have no direct, immediate effect on their utility's service costs.

The Commission also should consider DG's impact on the entirety of a utility's operations. Many of the most optimistic appraisals of DG's value focus exclusively on capacity, suggesting that a homeowner's installation of a rooftop PV system reduces a utility's potential long-term need to secure an equivalent amount of fossil fueled generating capacity. Such assertions

ignore the immediate need for adequate operating reserves to account for the inevitable unavailability of intermittent DG resources and other necessary utility service costs, such as providing adequate voltage support on its local distribution grid to accommodate variable PV output. While the Companies are working to address the integration challenges associated with rising DG usage, the expense of these efforts must be considered in any comprehensive analysis of DG costs and benefits.

In this context, the Companies offer the following comments on the relevance and significance of the categories of DG values and costs listed in Mr. Olea's letter.

Capacity

- Distributed Energy Capacity Value (MW) – Assigning a proper capacity value to the variable output of renewable DG is relevant and significant to the Commission's consideration in this docket. The output of rooftop PV systems typically peaks at midday but fades significantly by the late afternoon, when the summer load served by Arizona utilities is at its highest. Accordingly, DG capacity is valued for long-term planning purposes based on the extent to which its output is coincident to the utility's summer peak loads. For net metering purposes, though, this value may be diminished because DG output is less coincident with system peaks in shoulder and winter months.

- Avoided Generation Capacity (New Generation $) – This is potentially relevant and significant over the long term, as DG output is reflected in utilities' long-term resource plans. However, the Commission also must consider additional generation capacity and future energy storage facilities that must be developed to balance the variable output of planned DG additions. For example, the Reference Case outlined in TEP's 2012 Integrated Resource Plan demonstrates the need for approximately 300 MW of natural gas turbines between 2018 and 2024 to provide backup capacity for intermittent renewable resources. In the near term, though, these potential costs and benefits are not relevant for ratemaking or net metering tariffs.

- PV System Orientation – This is relevant, as PV systems can be oriented to maximize their output during peak load periods. While this increases their capacity value, it reduces their overall energy production.

Grid Support Services

- Ancillary Services
  a) Reactive Supply and Voltage Control – DG systems cannot provide these services because they typically operate at full output, where reactive supply is unavailable. Also, while PV system inverters may be capable of reactive supply or voltage control, these features cannot be accessed by utilities' energy management systems. As such, this category is irrelevant.
  b) Frequency Regulation – Renewable DG systems cannot provide automatic frequency control on par with fossil fueled units and typically devote their full output to energy production, leaving no capacity to provide frequency regulation for the grid. As a consequence, utilities must devote a larger share of their own resources to this necessary service, reducing the efficiency of their generating units and increasing overall energy costs. These additional costs are both relevant and significant.

c) Energy Imbalance – Because DG resources are not scheduled, they do not contribute to imbalances between scheduled and actual grid resources. DG intermittency does create load balancing challenges and can contribute to gas supply imbalances when utilities must ramp up gas-fired resources to compensate for unexpected shortfalls in solar production. While such challenges might be addressed through participation in an Energy Imbalance Market, the cost of establishing and operating such a market in the southwest region may exceed its anticipated benefits for Arizona utilities. These additional costs would be both relevant and significant.

d) Operating Reserves – The addition of intermittent DG systems to the grid forces utilities to increase the energy reserves they maintain to regulate voltage and recover from disturbances. Utility reserves must be sufficient both in size and operational capability (including location and response time) to account for contingencies that include the loss or reduction of renewable energy output. These energy reserves represent a significant, relevant and growing cost of DG.

e) Scheduling/Forecasting – Because renewable DG resources are neither monitored nor controlled by the grid operator, their intermittent nature complicates utility load forecasts and creates unanticipated intra-hour generation swings. When DG output drops below forecasted levels, utilities must either secure resources on the real-time energy market or ramp up local generation operations. The additional cost of these resources relative to those that might have been secured in advance represents a significant and relevant DG cost. Conversely, DG production that significantly exceeds forecasted levels may cause additional wear and tear on utility generating units forced to ramp down output to accommodate the discrepancy.

- DG System Integration Costs – This category is relevant and significant because utilities incur substantial costs to integrate renewable DG systems into their distribution grids without compromising reliability. These costs are described more fully below in the section addressing distribution system investments. DG integration also creates administrative costs associated with feasibility studies, interconnection agreements and facility inspections.

<u>Avoided Costs / Financial Risk</u>

- Avoided Power Plant Capital Costs (Customer's Capital Contribution) – Although energy efficiency and economic factors have reduced the projected need for new power plants, any such savings directly attributable to DG usage would be relevant if they materialize in the future. So too would any *additional* power plant capital costs attributable to DG, such as increased quick start generation to address intermittency. For now, though, DG systems obviously do not help utilities avoid the capital costs of plants already in service. Indeed, DG users depend on existing power plants for reliable service, since their utility's potential system peaks must account for periods when their DG system isn't producing power. Meanwhile, any future savings in power plant costs attributable to DG must be offset by the increased capital cost of quick-response generating units needed to balance their intermittent output.

  Avoided Fuel/Purchased Power Costs – Such savings are relevant and could be significant, though they would be offset by additional energy costs associated with increased DG usage. While DG does reduce the use of energy from other sources, utilities must nonetheless ensure that generation assets are available to respond to

customer load at all times. To the extent that this requires additional reliance on natural gas-fired turbines, utilities will incur higher gas pipeline costs and additional fuel expenses associated with these quick response units. These costs can be volatile, as evidenced by recent swings in the wholesale gas markets that boosted next-day prices at the El Paso-Permian hub from $4.50 to more than $24 per million British thermal units between Jan. 21 and Feb. 5, 2014.

- Avoided Fuel Hedging Costs – Such savings are unlikely to materialize because utilities will likely increase their reliance on natural gas to fuel the quick response turbines needed to balance intermittent DG output. That increased reliance would create higher hedging costs that could become relevant to calculations of DG costs and benefits.

- Avoided Line Losses – By reducing reliance on the output of remote, base-load generating plants, DG systems can reduce the amount of energy lost during long-distance transmission. The economic value of these reductions are relevant and could be significant, though it would be partly offset by increased distribution line losses associated with net metering and higher energy costs associated with greater reliance on natural gas-fired turbines.

- Avoided/Delayed Transmission System Investment – This is neither relevant nor significant. While increasing DG usage might reduce energy flows on existing transmission facilities, the historic investments in these facilities cannot now be avoided. Meanwhile, future transmission investments will not be meaningfully reduced by DG because utilities must account for peak usage during periods when renewable DG systems are offline.

- Avoided/Delayed Distribution System Investment – The growing use of DG will actually increase distribution system investments to a significant and relevant degree. Utilities will need to bolster their telemetry and frequency response tools to accommodate the intermittent output of grid-tied PV systems. In engineering terms, greater reliance on DG will reduce overall inertia on the distribution system, forcing utilities to compensate with increasing use of spinning reserves to avoid shedding load in response to frequency deviations. Meanwhile, the installation of larger DG systems often necessitates upgrades to local distribution and sub-transmission facilities to properly manage their output to the grid. The cost of such necessary investments in service reliability may ultimately eclipse any DG-related savings realized in other areas of utility operations.

- Avoided Renewable Energy Standard Costs – This category is not relevant, as any DG-related costs or savings utilities may realize in complying with the standard are anticipated by the rules themselves and are duly passed along to customers through the Renewable Energy Standard Tariff ("REST"). DG users should not receive additional compensation through rates paid primarily by other customers based on a claim that their renewable energy certificates ("RECs") can be secured more cheaply than those from other available resources. By that logic, utilities would be entitled to rates that reflect the most costly sources of power they might have purchased, rather than the resources they actually use. If the Commission were to eliminate the DG requirement, the owners of such systems would be free to market their RECs to utilities in open competition with other available renewable resources – thus realizing their true market value. Otherwise, it cannot be fairly said that DG resources provided under the terms mandated by the Renewable Energy Standard have "avoided" any costs.

- Avoided Utility Administration Costs –This category is relevant, but the Companies' experience suggests that DG has significantly *increased* utility administration costs. These costs include, but are not limited to, staff to work with DG customers and installers, increased information technology ("IT") infrastructure to manage regulatory reporting requirements, new reporting and administrative duties in metering and distribution services and additional training requirements to address safety risks posed by DG facilities.

- Avoided Market Price Mitigation (reduction of market clearing prices for natural gas and electricity) – The difficulty of proving any such effect likely renders this category irrelevant for ratemaking purposes. However, it would be reasonable to conclude based on the available evidence that DG actually increases market energy costs by boosting utilities' reliance on hourly power purchases and natural gas-fired turbine generators to compensate for intermittent PV output.

- Avoided Variable Operation and Maintenance ("O&M") Costs – While this category is relevant, DG actually increases utilities' variable O&M costs by introducing intermittency to a system better suited to stable power sources and more predictable load. Starting, spinning and stopping quick-response turbines and manipulating the output of larger plants to follow the variable load created by DG systems is expected to increase maintenance costs and shorten the useful lives of such units. This is particularly true for coal-fired plants, which are ill suited for following intermittent load. These impacts, combined with the cost of installing, maintaining and replacing the distribution system facilities needed to manage intermittency, would likely exceed the modest savings that might conceivably be realized through reduced midday load on distribution circuits serving DG users.

- Avoided Fixed O&M Costs – As with variable O&M costs, fixed O&M costs are not reduced by DG usage. Indeed, increased DG usage would likely increase fixed O&M costs for quick-response gas turbines on a dollars/unit of output basis, contributing to higher rates. Also, various distribution system components are subject to higher failure rates and/or shorter life cycles due to the voltage variations associated with increased DG penetration, leading to higher O&M costs.

- Avoided Power Plant Decommission Costs – At the point when it can be proven that DG usage has allowed a utility to avoid building a base-load power plant of a certain capacity, it might be possible to estimate the savings associated with not having to decommission a plant of that size at a theoretical location and designate that amount as a benefit of DG. Any such benefits would be offset, though, by the decommissioning costs associated with quick-response gas turbines and other facilities – such as energy storage devices – that will be required *because of* DG.

<u>Security and Reliability</u>

- Grid Security – This category is not relevant or significant, as DG systems do not meaningfully affect utility service costs associated with grid security. It may be suggested that DG enhances grid security by reducing reliance on energy delivered across long-distance transmission lines. But due to DG intermittency, utilities could not

rely on such resources to serve load in the event a transmission line is offline due to a security incident.

- Grid/Service Reliability – As noted above, the variable nature of renewable DG output challenges utilities' ability to maintain stable voltage and adequate inertia for safe, reliable service. Accordingly, the quick response gas turbines and other improvements necessary to maintain reliability amid growing DG usage can be fairly described as costs created by DG.

Environmental

- Water Consumption – This category is relevant. TEP's generating portfolio consumes, on average, approximately 605 gallons of water per megawatt-hour ("MWh"). While increased reliance on natural gas and renewable resources will reduce this average consumption over time, rooftop PV systems provide immediate reductions in water use by offsetting energy production from fossil-fueled units. These savings will be reduced somewhat by the water usage of natural gas-fired generators used to back up and balance the intermittent output of DG systems. The economic value of net water savings attributable to DG is difficult to quantify, though it should reflect the actual cost savings at power plants with reduced water consumption.

- Cost of Environmental Compliance – To the extent that DG allows utilities to avoid developing new fossil fuel generation resources, it also could be credited for reducing some associated environmental compliance costs, including lime, emissions fees or monitoring expenses. Similarly, DG would create new permitting and compliance costs for the quick response gas turbines installed to balance their intermittent output. Finally, the potential exists for increased environmental regulation of PV panel construction and disposal methods. As with power plant construction and decommissioning expenses, it would be inappropriate for these speculative future environmental costs and benefits to be reflected in utility rates until such time as they can be proven.

- Health Effects (Benefits) – Enthusiasm for solar DG and other renewable resources reflects their positive environmental impact, including the public health benefits that can be realized by reducing our society's reliance on fossil fuels. But even if that health benefit could be quantified, there would be no place for it in customers' electric bills. Utility rates are designed to recover costs incurred in the provision of service and to provide utilities an opportunity to earn a fair return on the capital prudently invested for that purpose. In this context, DG costs and benefits that do not affect a utility's cost of service – however meritorious they may be – are not relevant.

- Non-Compliance Environmental Effects – Because utilities would not realize cost savings for reductions in non-compliance environmental effects, this category is not relevant for ratemaking purposes.

Social

- Economic Development and Jobs – Although DG installations have created jobs and widespread economic activity, utility rates are not designed to bill or credit customers for such broad societal externalities. Thus, this category is irrelevant in this docket.

- Civic Engagement/Conservation Awareness – DG systems literally bring home the benefits of "green" energy to utility customers, helping reinforce broader marketing messages about the societal benefits of renewable power. Children raised in the shadow of rooftop PV arrays can be expected to grow into adults who embrace the technology as a standard component of our energy infrastructure. That such beliefs do not impact utility service costs does not diminish their societal value. It does, however, suggest that they are not relevant for ratemaking purposes.

- Ratepayer/Consumer Interest – Consumer interest in renewable DG technology is driven in large part by the savings that can be realized through its use, partially due to incentives, tax advantages and cost shifts subsidized by other customers. Those savings are likely to increase over time, in part because higher utility rates will be required to recover the fixed costs that DG users avoid paying. In Docket No. E-01345A-13-0248, the Companies advocated higher charges for DG users to offset this cost-shifting impact for non-DG customers. While such a charge could affect consumer interest in DG, it would nonetheless serve the best interests of all ratepayers.

- Ratepayer Cross-Subsidization – As discussed more broadly in in Docket No. E-01345A-13-0248, the use of DG creates significant cross-subsidies that contribute to higher electric rates. Because electric utilities recover their largely fixed service costs through usage based rates, DG users enjoy subsidized grid service at the expense of customers without such systems. Arizona's net metering rules exacerbate this problem by overcompensating DG users for their systems' excess energy. Importantly, these cross-subsidies will persist *regardless of the economic costs and benefits that may be attributed to DG users.* In other words, the DG benefits discussed in this docket do nothing to mitigate the acknowledged cost-shifting that such systems are causing today under Arizona's existing net metering rules.

- Technology Synergies – If DG usage by a particular utility's customers can be proven to have created technology synergies that led directly to a reduction in that utility's service costs, such savings could be reflected in rates for DG users. Short of that, though, the assignment of benefits for theoretical synergies achieved through DG use is far too speculative for ratemaking purposes.

- Energy Subsidies – Taxpayers and utility customers subsidize DG systems through credits, incentives and rates established by elected officials. These subsidies have significantly boosted DG adoption rates, increasing the impact of any associated costs and benefits for utilities. To the extent that such subsidies are funded through utility rates, they increase energy costs and promote cross-subsidization, as noted above. While the merits and economic impact of these subsidies can be debated in their own right, such issues are not strictly relevant to the discussion in this docket – the determination of costs and benefits created by DG itself.

Process and Methodology

The costs and benefits discussed herein should be viewed from a ratemaking and service reliability perspective. Accordingly, the process and methodology for assigning monetary values to relevant DG costs and benefits should reflect the standards applied in utility rates. Those standards include:

- Relevance – Costs and benefits that fall outside the scope of utility ratemaking should be discarded. While DG systems may create broad societal benefits, such benefits are irrelevant for ratemaking purposes unless they measurably reduce utility service costs. Moreover, any identified benefits must be balanced by any costs necessary to ensure the DG does not interfere with safe, reliable service.

- Timeliness – Just as utilities are generally precluded from recovering costs not yet incurred or for plant not yet in service, the quantified value of DG generally should exclude estimates of future savings not yet realized. For example, a new rooftop PV system should not be credited for avoided power plant capital costs until it can be proven that the local utility has, in fact, avoided building a power plant. Such a method ensures that DG systems are not overvalued based on speculation about future benefits that may not materialize.

- Evidence – Any costs or benefits attributed to DG should be proven to the standards appropriate for utility ratemaking. For example, utilities' load balancing costs should not be attributed to DG systems unless research or other evidence can establish that such facilities are necessitated by intermittent DG output.

Potential Presenters

The Commission would benefit from presentations by experts familiar with the challenges of integrating renewable DG systems into utility grids and micro-grids. For example, Sean Hearne Ph.D, Manager of Energy Storage Technology & Systems of the Sandia National Laboratories, could provide helpful information regarding the complex integration of disparate generation types into a micro-grid and the challenges of modeling the different technologies. Additionally, a representative of the Western Electricity Coordinating Council ("WECC") should be sought out to address how DG systems affect utilities' ability to comply with grid reliability requirements mandated by the Federal Electric Regulatory Commission. Finally, the Commission should analyze the experiences of other jurisdictions as it continues to evaluate the value and cost of DG.

The Companies appreciate this opportunity to comment and look forward to further discussion of these issues in the proposed workshops.

Sincerely,

Carmine Tilghman

CC: Docket Control
Commission Chairman Bob Stump
Commissioner Brenda Burns
Commissioner Bob Burns
Commissioner Gary Pierce
Commissioner Susan Bitter Smith
Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	))))	DOCKET NO. E-00000J-14-0023

EXHIBIT
TEP-2
ADMITTED

Rebuttal Testimony of

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company

April 7, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85702

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Senior Director of Energy Supply for Tucson Electric Power Company ("TEP" or "the Company") and UNS Electric ("UNS Electric").

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP") and UNS Electric ("UNSE").

Q. What is the purpose of your Rebuttal Testimony?

A. My testimony will focus on reiterating TEP and UNSE's (collectively the "Companies") position regarding the value of distributed solar and methods on how to calculate that value, as well as refuting a number of claims made by intervening witnesses.

II. COMPANIES' PREFERRED APPROACH TO CALCULATING COST AND VALUE OF DISTRIBUTED GENERATION ("DG").

Q. Please reiterate the Companies' expectation of an outcome for this Value of Solar ("VOS") docket?

A. We would like to see a clear definition and resolution to the following issues:

1. Clearly separating the utility's cost of service from societal and forward-looking benefits associated with solar.
2. Identifying the necessary revenue streams to fairly compensate both the utility and the customer.
3. Establishing an appropriate mechanism or model that provides the correct price signals to allow the market to respond to customer needs and allow technology to advance.

Q. Briefly describe the Companies' position regarding the preferred methods of calculating or assigning a value to DG.

A. As filed in my Direct Testimony, the desired complexity of the solution in this docket should dictate the extent to which the Commission strives for a detailed valuation of the costs and value provided by DG.

Should the Commission seek simplicity and a fair market proxy for the value of DG, it needs look no further than the wholesale solar market. Although there are a few differences between the two products (such as slightly lower distribution losses, loss of control and dispatchability, and interconnection value of 3 phase over single phase systems), the wholesale price still remains a viable proxy to the value of DG. The costs associated with the purchase of DG at this price could be easily recovered through the existing REST mechanisms concerning the calculation of the Market Cost of Comparable

Conventional Generation (MCCCG) and the above market cost (AMCCCG).

Should the Commission choose a more complex model to specifically address individual components associated with DG's value and cost, then the Company fully supports the use of the Value of Solar methodology developed by the Utah Public Service Commission (Docket No. 14-035-114). This model consisted of two primary components:

1) Known and measureable costs and benefits currently collected through rates (rate setting process), such as:
    a. Fuel offset/avoided energy
    b. Losses (energy/line)
    c. Administration and integration costs
    d. Ancillary services
2) External, societal, and future benefits for which a separate revenue stream must be identified (resource planning process), such as:
    a. Avoided generation capacity
    b. Avoided transmission & distribution capacity
    c. Avoided emission costs (CO_2, SO_2, NOX, etc.)
    d. Fuel hedging costs/savings
    e. Additional costs associated with operational compliance – integration costs
    f. Societal benefits

Under this particular model, a blend of historical rates and associated recovery through rate design is coupled with a resource planning value and an "as yet to be determined" source of revenue to pay for this value.

III. RESPONSE TO TASC WITNESS BEACH.

Q. Did you review TASC Witness Beach's testimony?

A. Yes, I did.

Q. Does the Company agree with Mr. Beach's statements and assessments?

A. No. The Company disagrees with the majority of TASC Witness Beach's assumptions, statements, and conclusions. He makes a number of erroneous statements and comments in his testimony.

Q. Do you agree with Mr. Beach's assessment that "to the utility the installation of such a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day"? (Page 12, lines 26-28)

A. No. What Mr. Beach fails to acknowledge is the difference between supplying a customer's full load through multiple resources (DG and the grid) versus the reduction of load from an efficiency measure. When a customer installs an energy efficiency measure, such as a more efficient air conditioner, the maximum overall load of the customer is reduced. This results in a reduction in demand on the system, both from an operational and a planning perspective. The failure of that air conditioner will not cause an increase in demand on the system, and the Company can reasonably rely on that load reduction for grid management and planning purposes.

However, the installation of a DG system, while reducing the amount of energy taken from the grid by the customer, DOES NOT provide an equal reduction of the customers' overall energy demand, nor does it provide a "one for one" benefit in the demand reduction on the utility's system. For planning purposes, the utility must still be able to

supply 100% of the customer's load when the DG system fails to produce. This issue is exacerbated during the winter months, as the customer's peak load is NOT during daylight hours.

Q. Do you agree with Mr. Beach's assertion that DG customers should not be treated differently than customers who employ other methods of cost-savings such as energy efficiency or demand response? (Page 13, lines 26-32)

A. No. As described above, a customer who employs a DG system to reduce their load is, for all intents and purposes, a partial requirements service (PRS) customer and they should be treated as such, with the appropriate demand charges and requirements associated with the applicable PRS tariff. This is especially true based on Mr. Beach's claims that DG exports are "often just 30% to 40%" (page 13, line 26), which establishes the fact, based on Mr. Beach's testimony, that a DG customer relies heavily on the utility to provide supplemental energy services, backup energy services, and ancillary energy services.

Q. Does Mr. Beach's testimony and his claim that the solar customer is not using utility system support the Company's position that the NEM rate should be based on a wholesale rate?

A. Yes. Mr. Beach claims the following (page 1, lines 14-23):

"With exported power, it is not the solar customer who is using the utility system, it is the utility and the solar customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. ***This is no different than when the utility buys power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's customers.*** *(emphasis added) Instead, that delivery service becomes the utility's responsibility when it accepts and takes title to*

the exported power at the generator's meter. As a generator, the only utility costs for which the generator may be responsible are the incremental costs of interconnecting to the utility system to enable the transfer of generation (and these are often paid by the customer-generator)."

Mr. Beach very succinctly highlights that transfer of ownership happens at the meter, and that the customer has ***no responsibility*** for the delivery of that energy to another end user. This is an equivalent wholesale energy transaction, whereby the utility procures energy at a point on its system and is responsible for all costs associated with delivery. Mr. Beach previously notes that most DG customers are "qualifying facilities" under Public Utilities Regulatory Policy Act of 1978 (PURPA), which specifically requires utilities to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs. (page 13, lines 2-14). Using Mr. Beach's arguments that a DG system is a PURPA facility (a position that the Company agrees with), and that the owner has no responsibility for delivery of energy after the utility takes receipt (a wholesale transaction), then it stands to reason that ALL energy exported from a customers' DG facility should be priced at the utility's avoided cost of energy as required by PURPA.

Q. Do you agree with Mr. Beach's statement that the utility does not incur costs to stand by to serve a solar customer when the solar customer is exporting to the grid?

A. No. Mr. Beach ignores several facts in his analogies, not the least of which is that a typical solar system is installed to help the customer achieve a "net zero" status on an annualized basis. This results in a solar facility size that is typically double the average customer load. Mr. Beach's statement that the loss of a DG facility is an equivalent load fluctuation to a customer who "*may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage*" is unreasonable and attempts to severely diminish the actual impacts of a DG customer on

the grid. The assumption that the sudden loss of 5-10 kW generating system has even remotely the same grid impact as turning on lights, a computer, and an appliance lacks any credible or substantive evidence.

Additionally, Mr. Beach's claims that as "one PV system is being shaded, another will be coming back into full sunlight" further highlights his lack of operational management experience in that Mr. Beach only views the loss and gain of generation systems (assuming they are equivalent) in total to the system load and ignores the dynamic impact to individual substations and feeder circuits.

Q. Under Mr. Beach's section titled, "Exploding Common Myths about Net Metering", he asserts that there is no cost to the utility to "store the excess kWh produced by NEM systems". Do you agree with Mr. Beach's assertion?

A. No. First, the Company is not aware of any widespread "common myth" regarding the actual storing of energy as it pertains to net metering. The Company believes that most entities operating in this industry, particularly as it relates to this docket and the parties participating, are fully aware that electricity is not "stored" per se, for later use. It appears that Mr. Beach has established this "myth" in order to over-dramatize his explanation of how the principles of net-metering actually work.

However, the assumption that there are no costs associated with net metering is inaccurate and fails to acknowledge real-time system operational issues. As Mr. Beach noted previously, the customer bears no responsibility for the movement of that energy once the utility takes ownership at the meter. Distribution wheeling is not free. Losses incurred are not free. Ramping and cycling of power plants is not free. Providing phase balancing and voltage stabilization is not free. The delivery of DG excess energy to the utility creates costs related to these aspects of grid management. All of these costs are

borne by the utility and are typically recovered through the volumetric rate design. Net metering allows the DG customer to avoid paying those costs, which are, in fact, paid for by the utility and ultimately by the non-DG ratepayer.

Q. Mr. Beach states that customer-generators should not be placed into their own rate class. Do you agree?

A. No. Customer-generators are by definition a Partial Requirements Service customer with distinct loading characteristics on the utility system. Contrary to Mr. Beach's' claims, it not only can, but should be, assumed that DG customers are significantly different than a typical customer. One need only look at the usage profile and additional requirements to serve an exporting DG customer to make that reasonable assumption. At the very least, they should be considered as a unique rate class during the evaluation of DG solar and its value and cost to the system, as is contemplated in the Utah model the Company supports.

Q. Do you agree with Mr. Beach's assertion that any new charge or rate design applicable to net-metered customers' needs to ensure economic viability?

A. No. Ironically, the rooftop solar industry has repeatedly criticized the utility industry as being subsidized, uneconomic, and attempting to stop the more "economic" option of solar. Any rate or charge applied to net metered customers should be based on actual cost to serve and should be compared to other technologies for cost-effectiveness (DG vs. utility scale). If that rate or charge renders DG uneconomic, then it is a policy decision of the Commission to determine if they want to further subsidize the industry in order to make it "economic".

Q. Do you agree with Mr. Beach's assertion that rooftop and utility-scale systems do not provide ratepayers with the same product?

A. No. Mr. Beach's entire argument seems to be based on the delivery point of the solar, and that since a retail customer is "behind-the-meter" it is an equivalent retail product simply because it displaces a ***portion*** of the retail product. This is a common misconception among rooftop industry representatives that solar DG is an equivalent product to grid supplied energy. It is not. It lacks several components of grid supplied energy, not the least of which is the inability to follow a customer's load, provide sufficient starting currents, and other necessary ancillary services that are still provided by the grid.

Additionally, Mr. Beach states that "*a minority of power is exported to the distribution grid, where it immediately serves neighboring loads*". This statement is an inaccurate statement, particularly as it applies to Arizona based utilities. A traditional Arizona-based DG system installed in TEP's service territory from 2013 to present pushed back 47% of the energy generated. While Mr. Beach's comments may be more accurate for older systems that were more expensive and smaller, this data is consistent given the considerable price decline in equipment and the lease model that proliferated in the 2012-2013 timeframe where systems were built to be at close to net-zero as possible to maximize the customer's financial benefit under NEM. And while 47% is technically still a "minority of power", it seems as if Mr. Beach is trying to marginalize the impacts of pushing excess energy back onto the grid.

Mr. Beach's unqualified statement that this energy is immediately consumed by neighboring loads is a common generality that inaccurately reflects distribution loads, and lacks any empirical data proving this statement.

Q. Do you agree with Mr. Beach's assessment regarding the "important policy reasons" why a state should maintain a supportive environment for customer-sited, distributed generation?

A. No. Again, Mr. Beach takes several liberties with his statements in "promoting" customer-sited distribution, specifically:

1. Stating that customers take greater responsibility for their supply of electricity is a misrepresentation of what it means to supply your energy. Mr. Beach ignores that a DG customer not only becomes immune to electricity consumption through utility and non-DG ratepayer borne subsidies under NEM, the customer does not provide all of the necessary components needed for power quality, instead relying heavily on the grid for support services, backup, and supplemental energy while being erroneously told by the rooftop solar industry that they are "self-supplying".

2. Mr. Beach depicts customer-provided capital as being "essential" to the movement of clean resources. However, unregulated expenditures outside the review of the Arizona Corporation Commission fails to protect the Arizona ratepayers from unnecessarily subsidizing one of the least cost-effective clean energy measures. Capital expenditures — and those who would provide the capital — should be subject to the same stringent regulatory oversight as the utility whose system is being impacted, while ensuring that the Commission has the ability to evaluate the prudency of this capital expenditure.

3. Falsely claiming that rooftop solar provides a "competitive alternative" to the utility's delivered power, and that it will spur the utility to cut costs and innovate its offerings. It is disingenuous for an unregulated entity to sell a product that is completely reliant upon the services provided through the regulated utility's infrastructure — an entity who fails to pay for those services and relies on

excessive above-market subsidies to pay for that product — to claim that it is the *utility* that needs to reduce its costs and become more innovative.

4. Mr. Beach's glaring omission that the ability of smart inverters to provide grid services is tied to the ability of being connected to the grid through a communications infrastructure that does not currently exist. Mr. Beach's "representations" of the smart inverter capabilities are little more pre-programmed set-points without effective — and secure — communications with the utility's SCADA system to receive grid management signals. Mr. Beach also erroneously, and without any qualified or fact-based empirical evidence, states that, *"by reducing load on individual circuits, rooftop solar systems reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it."*

   Below is a partial list of reports from considerably more qualified entities, all of which identify additional costs and O&M associated with variable generation, which includes rooftop DG.

   1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration".
   2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process".
   3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar

4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf
5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf.
6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf
7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling Costs".

5. Mr. Beach's attempt to characterize customer response to Nevada's net metering changes as their Commission being disrespectful to a customer's decision to invest in clean energy. As TASC's witness in this proceeding, it appears that TASC is implying that if the Arizona Corporation Commission doesn't continue with the "status quo" there will be a similar result in Arizona.

6. Mr. Beach's repeated mischaracterization that a customer is "self-reliant" and "independent", and that they are somehow identifying with the ideals fostered by our Nation's founding fathers. However, these DG customers remain connected to and dependent on the grid for reliable service, yet apparently expect non-DG customers to pay for the cost of the grid used to serve the DG customers. The Company believes that this type of misinformation and misrepresentation over customer-sited DG is partially responsible for the customer "enragement" in Nevada.

IV. RESPONSE TO VOTE SOLAR WITNESS KOBOR.

Q. Have you reviewed Vote Solar Kobor's testimony?

A. Yes, I have reviewed Ms. Kobor's testimony.

Q. Are there any specific points in which you agree with Ms. Kobor?

A. Yes, there are several points in which I agree with Ms. Kobor. First, I agree with her assessment of the customer's fundamental right to consume as much or as little energy from the utility as the customer chooses, and that such energy reductions should be addressed in a general rate proceedings. This concept is consistent with traditional volumetric rate design; however, this may not be ideal with regards to the appropriate valuation of energy consumed versus the energy pushed onto the grid. TEP and UNSE Witness Overcast provides a more detailed explanation of the Companies' position, as well as a more detailed discussion on buy-all/sell-all and why the need to account for all DG production (including that which is consumed on-site) in the valuation process. Additionally, we agree with the statement that this proceeding should develop a standardized approach and that the DG export valuation could be used in the utility's general rate case to inform DG rate design, as other intervening parties have mentioned.

Q. Are there any specific points in which you disagree with Ms. Kobor?

A. Yes, there are several points in which I disagree with Ms. Kobor, or at least would like to provide additional context to her statements. I will address the points individually.

Q. Ms. Kobor made a recommendation that any utility requesting reform of the existing DG rate structure use an "independent, third-party analysis using the standardized methodology developed in this proceeding". Do you agree with this recommendation?

A. No. The Company supports the development of a standardized methodology that **will** be used in each general rate case proceeding. The Company would support making it a mandatory recalculation during each rate case. As such, the Company should not have to request changes to the DG rate structure.

Additionally, the Company supports the development of a calculable rate methodology based on various supportable inputs. The mechanism for which the variables are derived should be developed in this proceeding. Ms. Kobor's request to have a third-party do the analysis — and then allow for stakeholder input to influence the outcome — implies that this proceeding leaves the parties with a subjective methodology for calculating the rate. As it is contemplated to be calculated in a general rate case, any party who disagree with the calculation performed in each rate case would have an opportunity to make their case for changes during the proceeding. The Company cannot support a methodology that is open to interpretation or based on subjective and biased opinions that are no better than what are arguing over today.

Q. Ms. Kobor has criticized the position that the use of cost-of-service ratemaking and the fact that cost-of-service ratemaking "fails to account to for the range of benefits DG provides". Do you have a response?

A. Yes. Ms. Kobor has mischaracterized the utilities' position. The utilities have consistently stated that the present cost-of-service model used for recovery of utility expenses is not conducive to evaluations based on "value", as value is not a recoverable cost component. The utilities have regularly requested that rate design be modified to allow for the just, fair

and reasonable recovery of the utilities expenses, and if the Commission chooses to do so, provide a revenue stream to compensate those DG customers who choose to invest in clean energy resources. Ms. Kobor, as with solar advocates, dances around the subject that it is the utility — and ultimately the ratepayer — that pays for that "value" in the form of higher rates under the current model. Regulated rate design specifically excludes "value" in the utilities rates, and there is no portion of the current electric rate design that a utility recovers that is intended to compensate entities for a "future value."

It should not be lost on the Commission that, should it determine that a DG customer is to be compensated *today* for a value it provides to other ratepayers in the *future*, there is effectively no savings to the non-DG ratepayers. They are simply paying today what they might be paying in the future under the cost-of-service model, assuming all of the projected assumptions are true.

Additionally, Ms. Kobor argues that the valuation of DG exports should include the long-term costs and benefits, such as was the case in the prudency evaluation of the Company's (TEP) purchase of the Gila River Unit 3. What Ms. Kobor fails to acknowledge is, that while the Company acknowledges the long term benefits of ownership of this facility, it does not — nor has the Commission ever granted — forward looking value on that specific acquisition. The Company justified its purchase through the evaluation of long-term benefits and then includes only the *known and measureable costs* in rates. This is not what the solar industry is proposing. They are proposing to be compensated for projected, assumed, and "as of yet to be realized" savings and subjective environmental values.

Q. Do you agree with Ms. Kobor's generalized statements regarding transmission, generation, and distribution savings, and that it will be more expensive in the long run for society if the Commission adopts a lower value based on cost-of-service structures?

A. No. Ms. Kobor's statements have no basis in fact. Generalized statements such as, "*DG provides significant benefits, including offsetting the need for additional generation, transmission, and distribution infrastructure.*" (Kobor Direct, page 12, lines 26-28) is reflective of someone with limited understanding and knowledge of grid management, utility planning, and operations. Ms. Kobor is not qualified to speak on these issues and does not provide any technical support for her general statements.

Q. Ms. Kobor referenced a report published by the Lawrence Berkeley National Laboratory ("LBNL") (Kobor Direct, page 13), stating an economist's view of how DERs can provide positive benefits to utilities and their customers. Did the report make any assumptions regarding regulatory policy, which may be more relevant to this proceeding?

A. Yes. One of the foundational assumptions of the LBNL analysis stipulated the following:

Continued policy mandates for reliability, safety, universal access and reasonable prices

We also assume that regulators and policymakers will maintain strong policy requirements for continued universal access to electricity service, as well as safety and reliability requirements comparable to those of today, and will continue to seek reasonable prices for customers. As with our other assumptions, we think this is both likely and helpful in focusing the policy analysis regarding appropriate regulatory paradigms for a high DER world.

While LBNL acknowledges that the continued use of policy is necessary to maintain a strong grid, an equally important component to this discussion is their continued reference

to "continued universal access to electricity service". LBNL states, "universal access to electricity service at reasonable rates is widely thought to make society more productive and efficient, suggesting positive social externalities for broad-based access to electric service." This positive societal value, while not reflected in the current model for utility rates, could be considered under the context of Chairman Little's request of whether or not the grid provides value to DER's.

Q. Ms. Kobor goes to great lengths to describe the need for the utility to provide transparency in their data, along with decade's worth of projected costs and utility rates, loss calculations, gas projections, and other recommendations. What is the Company's response to Ms. Kobor's recommendations?

A. For the most part, the majority of Ms. Kobor's requested data is already contained and used in calculations through the Company's production models to provide hour by hour cost projections. These calculations are used to calculate annual Market Cost of Comparable Conventional Generation ("MCCCG"), which is the avoided the energy cost. Delivered gas costs and projections are readily available and already used in these calculations, as is generator O&M costs and other variables. Although Ms. Kobor's loss calculation description is somewhat inaccurate, these values can also be determined more accurately through engineering modeling and actual data.

Q. Does the Company agree with Ms. Kobor's other assessment regarding the valuation of environmental attributes, compliance avoidance costs, emissions, water, economic benefits, and grid security?

A. No. Please refer to my direct testimony for more specific responses on these issues.

Q. Have you reviewed the testimony of the other parties?

A. Yes.

Q. Do you have any comments on the testimony of the other parties?

A. Although I do not concur with all of the arguments presented by several of the other parties, I am not providing any additional written comments as TEP and UNSE Witness Overcast sufficiently addresses the other issues.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	))))	DOCKET NO. E-00000J-14-0023

EXHIBIT
Hearing
TEP-3
ADMITTED

Direct Testimony of

H. Edwin Overcast

on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

February 25, 2016

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of Tucson Electric Power (TEP) and UNS Electric (UNSE or the Companies) collectively.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. Yes. I have testified on behalf of UNSE in their most recent rate case.

Q. PLEASE PROVIDE A LIST OF STATE AND CANADIAN JURISDICTIONS IN WHICH YOU HAVE TESTIFIED.

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas, Arizona and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. DURING YOUR CAREER HAVE YOU MADE PRESENTATIONS TO ENERGY RELATED TRAINING AND OTHER PROGRAMS?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee,

the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY ON COST OF SERVICE AND RATE DESIGN RELATED TO NET METERING, RATES FOR DISTRIBUTED GENERATION (DG) CUSTOMERS AND DEVELOPMENT OF RATES FOR PURCHASE OF ENERGY FROM DG CUSTOMERS?

A. Yes. My testimony in Maryland addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full Standard Offer Service (SOS) rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utility. I have also testified extensively in PURPA related proceedings on issue such as avoided cost and the purchase of energy and capacity from non-utility generators.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The Companies have asked that I discuss determination of the cost shift from DG customers to non DG residential customers based on principles of cost causation and using cost of service analysis. I will also address the issue of net metering and how it serves to create unwarranted subsidies for DG customers including rates that are not just and reasonable. I will discuss the valuation of solar DG based on sound economic and regulatory principles. Finally, I will provide an evaluation of the role and value of the

electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally. By combining sound regulatory and economic principles I will address certain questions raised by the establishment of this docket and the balancing of interests required by a prudent and least cost approach to utility service under the new mixed monopoly and competition model that has become the reality for utility service. Where possible, I will identify analytical frameworks that can address the issues of this docket and provide a foundation for the most efficient and economic provision of safe, reliable and cost effective end-use services required by customers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized by sections beginning with this introduction and followed by the following sections:

II. Some Initial Thoughts on the Mixed Competitive and Monopoly Model

III. Load Profiles for Solar DG Production and DG Customers System Usage

IV. The Cost of Service Approach

V. Allocation of Fixed Costs - Results of Three Studies

VI. Allocation of Energy Costs - Comparison of Residential Full and Partial Requirements Customers

VII. Solar DG Benefits - Near Term and Long Term Differ

VIII. The Outcome for Net Metering Must Meet the Objectives of PURPA

Each of these sections will be discussed below.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Using both cost of service for fixed costs and energy costs, I demonstrate the level of subsidy that results from both fixed costs and energy costs associated with net metering and banking. The level of subsidy is large and represents undue discrimination between

residential solar DG customers and the other full requirements, residential customers. Table 1 below provides the subsidy that result from each component of the rate and the total subsidy per customer.

Table 1

DG Solar Per Customer Subsidy by Component TEP

Source of Subsidy	Annual Amount per Customer (9645 Customers)
Non Power Supply Base Rate	$729 - $822*
Banking Arbitrage	$11.18
Excess Generation	$73.42
Premise Use	$60.13
Total Per Customer Subsidy	$873.72 - $966.72
Total Aggregate Subsidy	$8,431,948 - $9,328,933

* Based on the current cost of service and the cost of service for solar as a separate class of residential customers. This is consistent with utility ratemaking.

This is a large subsidy on a per customer basis. Individual subsidies will vary based on the size of the DG system. As such these subsidies are far larger than the subsidies that result from averaging costs over a class of customers. Based on this analysis, the current net metering with banking and the use of a less than compensatory customer charge and kWh billing makes it impossible to conclude that the resulting rates are just, reasonable, equitable and non-discriminatory.

I explain why solar DG customers need to be treated as a separate class for cost of service to properly reflect cost causation. I also show that there are no avoided distribution costs

as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system occurs when solar DG customers are delivering excess generation to the system and there is no time diversity of solar DG production as there is with customer load. This is equivalent to stating that DG customers have their highest class NCP based on generation delivered to the system rather than net load on the system.

My testimony explains that economically efficient rates need to unbundled and each utility service priced separately so that customer make efficient decisions about the services they use. The unbundled rates include customer charges, demand charges and all energy related costs recovered outside base rates on a TOU basis that reflects the differences in marginal cost by season and by period for each day of the season.

I also show that efficient, market based capital avoided cost payments should be based on a proper calculation of avoided capacity costs and reset annually as the lower of the capacity market or the utility avoided cost. Solar DG customers should be compensated for avoided capacity based on the particular year when their production avoided costs occur over the useful life of the DG facility at a levelized annual rate determined each year.

II. SOME INITIAL THOUGHTS ON THE MIXED COMPETITIVE AND MONOPOLY MODEL

Q. PLEASE EXPLAIN THE CONCEPT OF A MIXED MONOPOLY AND COMPETITIVE INDUSTRY MODEL.

A. This is not a new concept as other industries have been faced with similar issues. In some cases the very existence of the monopoly model has been replaced by competition entirely such as the case of the airlines and the trucking industry. In others regulators

have developed tools to address the mixture of competition and regulation. Two examples that come to mind are railroads and liquids pipelines. There has also been an evolution of the mixed model in the electric industry. A major force behind the analyses of these events was Dr. Alfred Kahn who served as a Federal Regulator (the Civil Aeronautics Board), a State Regulator (Chairman of the New York Public Service Commission) and a regulatory scholar (The Economics of Regulation and any number of economic articles, papers and testimony).

Dr. Kahn described this model in a 1998 monograph published by The Institute of Public Utilities and Network Industries at Michigan State University. That Monograph entitled "Letting Go: Deregulating the Process of Deregulation" provides the description of the model as follows:

> It is clearly not possible to totally eliminate direct regulation of what we have traditionally considered to be the authentic public utilities. The reason, of course, has been the persistence of monopoly, particularly in the local distribution networks and also in electric transmission, which has required continuing regulation for two closely relate reasons:
>
> - To protect captive, principally residential and small business , customers;
> - To ensure fair and efficient competition between the integrated utility companies and the challengers dependent upon their access to their monopolized or partially-monopolized facilities, including safe guarding against cross-subsidization of that competition by the incumbent utilities at the expense of their monopoly customers.[1]

This is the fundamental concept of the mixed monopoly and competition model. Namely certain aspects of the public utility remain a natural monopoly, in particular the facilities

[1] "Letting Go: Deregulating the Process of Deregulation", Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 17

associated with service delivery and more as will be discussed later. Several parts of this discussion apply to this proceeding. First, regulation is needed to protect the captive residential customers who cannot (or choose not to) avail themselves of DG or net metering, recognizing that this is at least a plurality and more than likely a majority of the residential class. Second, Dr. Kahn notes that competition should be fair and efficient. As I will explain later in this testimony the implications of net metering are such that the competition for the end use loads served by DG is neither fair nor efficient under the net metering, banking and volumetric rates commonly used for residential service. Third, and more importantly, I will show that net metering creates cross-subsidization, not by the incumbent utility, but by the rent seeking[2] behavior of the solar DG advocates that occurs at the expense of customers who remain monopoly customers.

Typically, the argument for this rent seeking behavior is that it will have a small dollar impact on customers providing the subsidy and the industry cannot make it on its own initially (the infant industry argument). Dr. Kahn specifically recognizes this behavior by these entrants and summarizes the impact of this behavior by noting "the encouragement that preferential subsidies and protections of this kind give to would-be competitors to devote their entrepreneurial energies primarily to seeking such preferences and ensuring their perpetuation by interventions before regulatory agencies and the courts, rather than concentrating on being more efficient suppliers than the incumbents."[3] With regard to solar DG the proliferation of roof top solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as the utility costs benefit from scale economies. This is demonstrated by

[2] Rent seeking is the activity of a person or firm that tries to obtain benefits for themselves through the political arena- the Arizona Corporation Commission in this case as well as legislatively through the PURPA amendment adding the net metering standard. Typically the benefit consists of a subsidy for their product or service including favorable tax treatment and measures that inhibit competitors such as inefficient regulated rates.

[3] Kahn, op. cit., page 21

the lower market price for solar when the price is market based compared to the implied price (with subsidies) associated with net metering. Particularly given that DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year round contract for solar generation. This is just another example of how markets have both a competitive option and regulation of the remaining natural monopoly.

Q. WHAT ARE THE ESSENTIAL ELEMENTS FOR THE REGULATED DELIVERY COMPONENT TO AVOID CREATING CROSS-SUBSIDY FROM THE MONOPOLY COMPONENT OF THE MARKET TO SOLAR DG CUSTOMERS WHO HAVE CHOSEN COMPETITIVE ALTERNATIVES?

A. One of the characteristics of true competition is that subsidies are not sustainable. Under regulation artificial subsidies may be sustained for a longer period of time but must be addressed ultimately if utility service is to be sustainable. Where the competitive market is subsidized through regulation, the result is that there is excess and inefficient investment in the favored competitive services such as solar DG in this case. The result will not be consistent with least cost planning or even efficient operation of the monopoly portion of the market. Ultimately, the monopoly segment of the market must establish fully unbundled rates so that when a customer uses a monopoly service the customer pays for the costs that that use imposes on the monopoly. To establish unbundled rates the cost of service must be unbundled for the services provided. Rates must be developed that signal the factors that cause cost by customer groups that have homogeneous characteristics that cause the cost. When rates reflect class cost of service on an unbundled basis and the underlying cost of service reflects the principles of cost causation and matching, subsidies will be eliminated; the price signal in the rates will incent efficient use of resources; rates will be just and reasonable; rates will not be

unduly discriminatory; investment in DG will be consistent with least cost planning and efficient competitors will earn the required market return for the risk associated they take. In summary the following elements must exist for long term stability and sustainability of the mixed market model:

1. Cost of service reflects cost causation for each class of customer.
2. Rates match cost in the rate effective period.[4]
3. Rates are fully unbundled such that all energy related costs are recovered in energy charges (preferably seasonal and time differentiated based on marginal cost differences), fixed capacity costs are recovered in demand charges and customer costs in customer charges that may not be the same for all customers in a class when the services they select differ.
4. Price signals should reflect marginal cost to the extent practical while still matching costs and revenues.
5. Costs not included in test year revenue requirements such as the present value of future avoided costs or the levelized cost of future avoided energy should not be part of rates or part of valuation of assets that have no long-term, enforceable, contractual obligation for service and even with a long-term power purchase contract energy should be valued at the market as the market changes through time.

[4] The rate effective period is the first year after new rates take effect. This is simply a statement of the court mandated requirement that rates provide the utility a reasonable opportunity to earn the allowed return not only in total but that the rates match the cost of service by class of customers.

Q. IN ESTABLISHING CLASSES OF SERVICE IN THE MIXED MONOPOLY AND COMPETITIVE MARKET, WHAT ARE THE ESSENTIAL ELEMENTS SUPPORTING RATE CLASS DETERMINATION?

A. It is essential that rate classes be established based on factors that cause known differences in cost of service. These factors include voltage level of service- secondary, primary, sub- transmission and transmission or some subset of these factors based on the types of service the utility provides. Voltage level is important because it impacts energy costs (delivery losses) and capacity costs (extra equipment not used by other classes of service and the required level of capacity). Quality of service (firm or non-firm) is another dimension for determining the classes of service. Type of service is another dimension such as full requirements or partial requirements that result in different demand characteristics for different portions of the system. Special service arrangements may impact the definition of classes. This would include customers who require redundant facilities for reliability or unusual load characteristics such as very low load factors. Finally there may still be a need to recognize differences by traditional end use classes such as residential, commercial, industrial or size of customers within a class. The need to create multiple rate classes based on cost causation will be reduced. So the number of rate schedules in a tariff should be more manageable.

Q. YOU NOTED A DIFFERENCE BETWEEN FULL AND PARTIAL REQUIREMENTS CUSTOMERS. PLEASE EXPLAIN THAT CONCEPT.

A. Full requirements customers are those who purchase the full bundle of services provided by the utility. Partial requirements customers are those who choose to select only some of the services provided by the regulated utility. To the extent that the selection of the services provided by the utility results in a different mix of hourly loads and more or less

use of particular services provided by the unbundled utility, the partial requirements customers must be treated separately for cost recovery for rates to be just and reasonable. There are many different categories of partial requirements customers. For example, customers who buy competitive generation services while using the utility for delivery of those services are no different with respect to delivery services than full requirements customers who use delivery services for utility generated services. By unbundling delivery service from generation services customers in the same class may make competitive choices and pay rates that are just and reasonable for delivery regardless of the source of energy and capacity for generation.

For other partial requirements customers the competitive services they purchase may change the cost characteristics for the customers. A simple example will illustrate this concept. Suppose a customer owns a run of the river hydroelectric generator that is used for supplying a portion of the customer's energy and capacity. By its nature a run of the river facility has highly variable output based on weather. During rainy periods the output is higher than dry periods when output may even be zero. For a summer peaking utility that may mean that there is no capacity at the generation peak of the utility and thus no capacity savings from the facility but only energy savings. It is likely that the facility produces its maximum output in the spring and fall so that the energy value is even less than the average energy value. As for delivery charges-transmission and distribution the customer looks just like any other summer peaking customer for those charges as well. The potential for cross subsidy from other customers is high if costs are recovered in a simple two-part rate using average kWh charges. The subsidy is minimized if demand costs are recovered in demand charges, customer costs in customer charges and energy costs are based on seasonal time of use kWh charges.

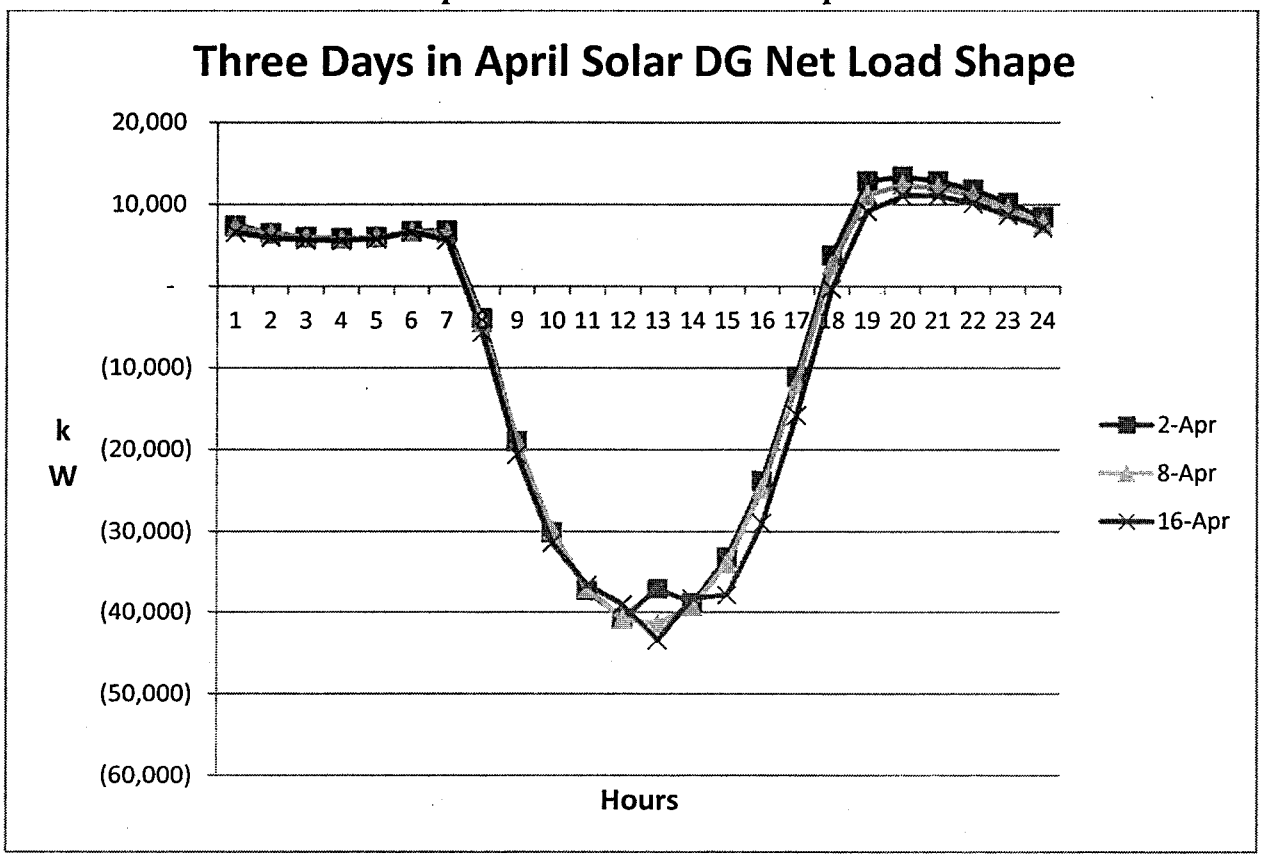
Q. WHY WOULD A UTILITY NEED A SEPARATE RATE CLASS FOR PARTIAL REQUIREMENTS CUSTOMERS?

A. A separate class for partial requirements customers is needed when the customers use the system differently than other customers who have the same end-use loads. Different usage patterns result from how a partial requirements customer uses the system. Solar DG customers provide an excellent example of a group of residential customers that use the system very differently from full requirements customers. These customers use the system for much more than the delivery of kWhs they consume when solar DG is not available or inadequate to serve the total hourly load. Some differences include the use of the system for the sale of excess kWhs back to the system. Under net metering with a banking provision solar DG customers use the system for virtual storage just as if they had a very large battery that would allow them to put kWhs in the battery in low load periods and draw them out of storage to offset purchases in high cost periods. This is a service that is free under net metering but is not free from subsidy from other customers who pay for the storage service and the price differential between high load, high cost periods and low load, low cost periods. Other customers also pay for the losses associated with the delivery to storage and the delivery back to the customer under net metering where there is no loss adjustment associated with the transaction. The solar DG customers also use the distribution system differently. The reason that the distribution system is used differently is that while there is natural diversity in customer loads that produce the class load NCP, there is no natural diversity at the class NCP for solar DG sales of excess generation. The maximum output of all of the solar DG customers occurs at the same time because the DG facilities are all or predominately designed to maximize kWh production and are fixed axis solar DG installations. The peak production occurs on the coolest day in the spring and at mid-day. There is no diversity in the sense that some customers peak later or on a different day because of the inherent technological and

operating characteristics of solar DG. In a sense this peak is like the gas system peak that occurs for all heating customers on the same day based on the weather conditions. This means that it is possible that the class NCP for solar DG actually occurs on a day not based on load but based on delivery of power back to the grid. That is the case for TEP where the delivery NCP is greater than the load NCP. The solar class NCP occurs at noon in March or April when almost twice as much power is delivered to the system than the solar class contribution to the load NCP on the hottest day in the summer. Figure 1 below illustrates the nature of the generation delivery to the utility system for three days in April where the highest delivery is 43,429 kW at 13:00 hours using the hour ended concept used by utility dispatch.

Figure 1

April Solar DG Net Load Shape



The distribution system must be able to accommodate bi-directional delivery service and serve the load at which ever maximum occurs- either load NCP or generation NCP. This high load also raises marginal losses on the local facilities that impact the net delivered power from solar DG for the grid.

To properly allocate delivery service costs to DG customers it is necessary to recognize the actual class NCP. It also means that for customers who respond to the energy price signal and size their system to minimize the utility bill there are no possible distribution cost savings. This also means that when kWs are sent back to the system in these low load periods the system power factor deteriorates because solar generation produces no vars. In order to resolve the lower power factor associated with solar DG it is inevitable that distribution costs will increase as the utility installs switched capacitors to manage the system power factor. The alternative to the low power factor is to require smart inverters as part of the interconnection standard. This is similar to the provisions in rates for larger customers that either bill customers on a kVa basis or include a power factor adjustment provision that recognizes lower power factor has a cost as in the large customer rates for TEP.

There are other uses that solar customers make of the system such as synchronization of solar generation with the grid, in rush current, supplemental service and backup service. These services all result in differences between the residential solar DG customers and full requirements customers. For example when a full requirements customer uses in rush current to start a motor load there is also kWh use that is billed. For a solar DG customer there is no kWh use when the solar DG is operating and meeting the load but the in rush current is used. The pattern of supplemental service is such that solar DG customers require utility service in some of the highest cost hours based on the limited energy from solar DG in those hours. These are all unbundled services used by solar DG

some of which they do not compensate the utility for the costs they cause and others which they pay less than the full costs under the two-part rate.

III. LOAD PROFILES FOR SOLAR DG PRODUCTION AND DG CUSTOMERS SYSTEM USAGE

Q. IS IT POSSIBLE TO ILLUSTRATE THE PROFILE OF SOLAR DG OUTPUT AS IT COMPARES TO HOURLY MARGINAL COSTS?

A. Yes. Exhibit HEO-1 provides a comparison of solar DG production from a fixed axis south facing facility and the hourly load profile of the TEP system. It shows that the solar peak output is either declining or zero at the time of the monthly system peak loads. Exhibit HEO- 2 provides a comparison of solar production from a fixed axis south facing facility to the hourly marginal costs for TEP system. As that data shows in many high cost hours the solar DG production is declining or zero and that peak production hours uniformly do not match peak marginal cost hours in either the summer or the winter. The mismatch is even greater during the peak day because of the impact of ambient temperature on solar DG output. As the temperature of the facility rises above 25 degrees Centigrade (C) (77 degrees F) , solar output declines at a rate of about four tenths to one half of a percent per degree C. If the solar panel is cooled passively by ambient air flow the output loss for the average peak day temperature in Tucson would be about 9% of rated kW capacity. If the panels are not cooled (mounted on the roof directly) the panel temperatures could reach 60 degrees C and reduce output by 17.5% of the standard rating. Conversely, when temperatures are below 25 degrees C the output of the solar DG exceeds the rated capacity by about the same one half percent per degree C. As a practical matter this means that the maximum solar output occurs in March and April low

load periods that are between one half and two thirds of the class NCP peak load for typical full requirements residential customers.

Q. WHAT ARE THE SYSTEM IMPLICATIONS FOR MAXIMUM OUTPUT DURING LOW LOAD PERIODS?

A. When the hourly output maximum occurs in low load periods more of the output flows on to the system and places more demand on the distribution facilities required to provide delivery service of excess energy as shown above in Figure 1. In simplest terms the diversified demand of residential DG customers delivering power back to the grid at the midday hours, weekdays in March and April is larger than both the customer NCP load demand and the residential class NCP demand. Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers. This further confirms that the distribution system must be designed to meet this higher solar class NCP load rather than the residential class customer NCP load used for full requirements customers. The maximum average customer NCP (the sum of the highest hourly loads for all customers in the data base) for full requirements customers occurs in July at 12.87 kW per customer. The maximum excess delivery by a partial requirements customer occurred in April at 13.79 kW per customer. Although the differences are small, about one kW, the data confirms that there would be no distribution cost savings associated with the equipment in accounts 364-368. The logic behind the high level of excess delivery in that time period is quite simple when one considers that the average kW load for residential customers in the noon hour in March and April is 0.75 kW per customer. For even a small 5 kW solar DG facility

the extra output above the nameplate wattage would result in about 4.5 kW flowing back to the system. Taken with other load data on class NCP it is also reasonable to assume that there would be no savings at the substation level for peak loads of solar DG customers.

It also points out that there will be losses associated with the excess energy before it is delivered to other customers meaning that the virtual storage of excess generation is reduced by losses when the kWhs are delivered to the system and additional losses when the kWhs are returned. In simple terms the banking provision creates a subsidy from not only the timing of the kWhs but from the smaller amount of kWhs actually banked and delivered. I asked the Company engineers to estimate the losses associated with this excess energy flowing back onto the system. Exhibit HEO-3 shows the losses on a one line diagram for delivery to other customers and the system prepared by the Company. There are several important points to recognize in this analysis. First there are real losses even for one solar customer on a typical installation. Second, even with only a single solar customer load flows back on to the delivery system in these low load high production periods. That is, all of the output is not consumed by the other customers on the same transformer and even if it all was consumed there are still real losses. Third, this analysis is conservative because it does not assume any impact associated with delivery of Vars. These losses are only part of what should be counted as losses associated with the solar service because that service is not available without the system no load or core losses as well.

Another implication relates to the increased losses for the var requirements that must be produced by the utility system to deliver the pure kW sent to the utility system. Although it is not possible to quantify these extra costs in detail it is important to understand that these services are not free and that other customers provide additional subsidy to solar DG customers that are not included in either the cost study for fixed costs or in the

marginal energy cost analysis. Rather, it is reasonable to conclude that the subsidy from full requirements customers is conservative estimate.

Q. PLEASE EXPLAIN WHY YOU HAVE USED TWO DIFFERENT DATA SETS FOR SOLAR LOAD PROFILES IN YOUR ANALYSIS.

A. Both data sets have value for analysis depending on the purpose of the analysis. In this case, the actual data from Rio Rico provides a better representation of actual hourly loads because it is able to reflect both temperature impacts and local weather variations. The NREL data is used as a second source of solar output to confirm the results from the full analysis based on Company data alone.

Q. PLEASE DISCUSS THE ROLE OF LOSSES IN CALCULATING DG BENEFITS AND COSTS.

A. Solar advocates argue that because DG is behind the meter that avoided losses should be reflected in both cost analysis and in computing the benefits of DG. Most of the discussion around losses makes statements such as the avoided losses are higher than average losses. These statements ignore the economics of losses because the no load losses are not changed as part of the calculation of marginal losses and the low power factor for DG customers results in higher losses that the average when power is consumed. For example, if the power factor for a customer was 50% the current required to serve the load would double. As current doubles the losses increase by I^2 or 4 times the losses of pure power.

Q. HOW DOES THIS LOAD INFORMATION IMPACT COST OF SERVICE?

A. While I will explain the impact on the cost study in more detail below, this data means that the allocation of distribution costs for solar DG customers who have little or no

diversity in their production loads on the distribution system cause higher total delivery costs than would be reflected by including those customers as residential customers in the costs study. Using the residential load data will result in too little cost allocated to the partial requirements DG customers because these customers are larger than the average customer. To develop a cost study based on cost causation the partial requirements DG customers should be treated as a separate class and allocated costs based on their own class NCP for distribution. The different load demands on the system from the two classes as well as the energy price arbitrage that occurs under net metering with banking requires treatment of solar customers in their own class.

Q. DO THE DIFFERENT COST CHARACTERISTICS IMPACT RATES FOR PARTIAL REQUIREMENTS CUSTOMERS?

A. Yes. Portions of the unbundled rates for partial requirements customers will be different from full requirements customers. There will be no difference in the seasonal TOU energy rates since the service to both groups will be based on service at the secondary level. The demand and customer related costs will be different and those portions of the rate should reflect the differences in per unit costs. In part, this is because the partial requirements customers are lower load factor customers from the system delivery perspective. It is also true that these customers use a different set of services than full requirements customers and hence cause different costs to be incurred.

IV. THE COST OF SERVICE APPROACH

Q. PLEASE DESCRIBE THE COST OF SERVICE STUDIES DEVELOPED IN THIS CASE.

A. There is no practical way to assess the costs caused or the revenue requirements for full and partial requirements customers without developing a cost of service study that identifies these two classes of residential customers in separate classes for fixed costs and in separate studies for variable energy related costs. I have prepared three different cost studies to allocate the fixed costs of TEP based on the cost study filed in the current TEP rate case. I say fixed costs because the three studies produce results that only allocate costs that are classified as customer or demand costs and do not include any costs classified as energy. I will refer to these three studies collectively as the fixed cost studies. The energy cost studies use hourly costs for full and partial requirement customers to assess the energy related costs and include an analysis of marginal energy costs for each category of residential customers.

Q. PLEASE DESCRIBE THE THREE FIXED COST STUDIES.

A. Based on a decision by the Public Service Commission of Utah in Docket No. 14-035-114 issued November 10, 2015, the Utah PSC adopted a methodology of comparing two cost studies to determine the costs of serving solar customers for ratemaking purposes. The first cost study is the standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class. The second study that Utah refers to as counterfactual cost study (CFCOS) assumes that the solar customers did not adopt DG but rather were full requirements customers allocated costs in the same way as the residential class. This study is essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the

customer premise. By comparing these two studies it is possible to identify the way costs change for both full and partial requirements customers assuming that the load characteristics in terms of both load and delivery capacity requirements are no different. All other things are not equal when viewed from the factors that cause costs. Since we know that the load characteristics are not the same, I recommend a separate class for evaluating the embedded costs of solar DG customers rather than using the counterfactual study alone with its inherently biased assumption about cost causation. That is the third fixed cost study I have included.

For each cost study we use the same fixed costs for the system based on the 2015 rate case costs as filed in the TEP cost study. Those fixed costs are allocated using the same basic methodology of average and excess for production costs and the minimum system customer costs and class NCP for demand related delivery costs. We also use the same customer cost allocations. Using the same customer cost allocations is a conservative approach because TEP has made no effort to account for the higher level of transaction costs for solar DG customers associated with storage accounting, billing adjustments and other customer service considerations. The study is also conservative because we have made no attempt to identify any system investments designed to address power factor issues or other distribution related investments. There is also no adjustment for higher losses associated with the power factor issue noted above.

Q. PLEASE DESCRIBE THE TWO ENERGY COST STUDIES.

A. As noted above the load shapes of full and partial requirements customers are significantly different in terms of how the system must respond to the load shape of solar DG customers as compared to the full requirements customers. In addition to the load shape differences, solar DG alters system dispatch because of the nature of the net load shape for these customers. The net load shape for solar DG customers in the spring

months of March and April and the fall months of October and November is illustrated in Exhibit HEO-4. The significance of these months for system operation is that these are the months when utilities typically schedule baseload and other units for maintenance. In considering the total demand on capacity (the sum of load demand, scheduled outage demand, forced outage demand and unit deratings) these months may have higher total demand on capacity than other months although typically not the peak months. This implies less flexibility to meet load when loads increase rapidly as it does on almost every day in this period. This results in higher marginal costs because the loads must be met by fast start units that are typically combustion turbines. It also means that ramp rates become an important consideration for maintaining spinning reserves and operating reserves. The two energy studies compare the dispatch of the system with the assumption that the total load was from full requirements and partial requirements customers and the actual dispatch reflects the variability of solar DG in the loads. This is another example of the conservative nature of the analysis when compared to separate dispatches of the two groups.

Q. PLEASE EXPLAIN THE DIFFERENCES IN THE TWO ENERGY STUDIES.

A. The first study is the hourly energy costs based on the expected load in the test year including the solar DG load. The second study uses the counter factual load shape and excludes the sale of excess energy back to the system since under the counter factual analysis there is no excess generation. We have used the hourly energy cost analysis to also compare the marginal and average energy costs associated with the full requirements residential customers and the partial requirements DG customers. We have essentially used a production costing model to compare energy costs with and without solar DG. All of these results will be discussed below.

Q. DO THE COST STUDIES COMPLY WITH THE PRINCIPLE OF COST CAUSATION?

A. Yes. The studies follow the standard process of functionalization, classification and allocation for each unbundled component of costs. Costs are functionalized as generation, transmission distribution and customers.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load. In this case, this is allocation of the expense transmission by others.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

Q. WHAT IS CLASSIFICATION?

A. Once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors

that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. This is a particularly important concern when developing costs for customers who use the system differently and who create new costs to accommodate the customers' system impacts.

Q. WHAT ARE DEMAND COSTS?

A. Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Q. WHAT ARE ENERGY COSTS?

A. Energy costs are those costs that vary directly with the production of energy such as fuel costs, other fuel related expenses or purchased power expense.

Q. WHAT ARE CUSTOMER COSTS?

A. Customer costs are those costs that vary with number of customers such as meters and service lines.

Q. CAN COSTS BE CLASSIFIED INTO MORE THAN ONE CATEGORY?

A. Yes. For example, some distribution costs may have both a demand and a customer cost component.

Q. WHAT IS THE ALLOCATION PROCESS?

A. In this step, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that

cause the costs to be incurred.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED ALLOCATION FACTORS FOR THE STUDY.

A. To develop the allocation factors for the cost study it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.

Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data the process consisted of a number of logical steps as follows:

1. Using basic number properties of mathematics we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the system. From this calculation we saved both the premise load and the excess energy for use in the various analyses. The value of this calculation cannot produce negative kWh. As a result, we eliminated about 200 observations from the data set because the excess kWh sold back to the utility were not possible. For example in one case the kWhs delivered to the utility in a month exceeded

83,000 for a DG facility with 8.42 kW of capacity; a result that is physically impossible. This is an example of an obvious data error.

2. Using monthly total energy consumption of the premise and the residential hourly load shape based on the customer's monthly premise use, an hourly load shape of premise use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape.
3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual cost study.
4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value. (The Company data set did not have a kW capacity for all of the solar customers and those were excluded from the analysis.)
5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.
6. The solar net load shape is the premise hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base fixed cost study.
7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile and the solar customer net load profile.
8. Using this data it is possible to calculate the solar customers demand allocation factors for each fixed cost study and for the energy cost studies.

9. For the counterfactual profile we calculate the residential class Average and Excess Demand (AED) and NCP allocation factors and rerun the cost of service study. We also use the net load profile and calculate the AED and NCP allocation factors using only the net positive energy for AED and the higher of the positive or negative class maximum NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

This data provides a solid, if conservative, basis for assessing for assessing the relative revenue requirements differences between the between full and partial requirements customers.

Q. HOW DOES ONE DETERMINE THE FACTORS THAT CAUSE COSTS?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of the cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident

peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Q. WHY ARE THE PROCESS OF COST OF SERVICE AND THE PRINCIPLE OF COST CAUSATION SO IMPORTANT IN ASSESSING NET METERING POLICY AND RESULTS?

A. It is important to recognize that there are many different views on cost of service. Different views are driven by the zero sum nature of the cost study. When customers can develop positions on allocation that benefit their constituents there is an opportunity to have more favorable rates. This is consistent with the underlying concept of rent-seeking without having to specifically request a direct subsidy although some advocates engage in both types of behavior. For example, solar advocates often recommend cost allocation methodologies that minimize the customer component in order to maximize the kWh charge in the two-part rate. It is not uncommon for these advocates to recommend use of the basic customer method to allocate customer costs because this method produces the lowest possible customer charge other than recommending zero.

Q. PLEASE COMMENT ON THE BASIC CUSTOMER METHOD.

A. The basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs. It is simply a result driven methodology (lower costs for the residential class and for smaller customers in the class and higher per kWh charges under the current two part rate design) that does not meet the criteria of theoretically sound cost causation. As a result, all of the remaining distribution system costs must be classified as demand and allocated on some measure of NCP. This

includes USOA accounts 364-368. By failing to classify accounts 364-368 as both customer and demand, the resulting cost analysis suffers from significant defects related to cost causation.

First, residential customers are allocated a disproportionate share of scale economies in the distribution system. Residential transformers in account 368 have substantially higher costs per kVa of installed capacity than larger demand customers, typically more than twice the cost per kVa. Demand allocation alone assumes the same cost per kVa for all classes.

Second, the use of demand to allocate costs for investments in accounts 364 through 367 over allocates the quantity of these inputs to larger customers who have higher NCP demands and assumes that miles of conductor is proportional to demand and not to number of customers. This is empirically an incorrect assumption.

Third, public utility regulatory accounting including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. Based on these factors the Basic Customer Method is never a viable alternative for calculating the facilities charge. Thus TEP in its study and in the alternative fixed cost studies use the minimum system that recognizes the customer portion of delivery costs.

Q. HOW DOES THE AED METHOD FOR ALLOCATING GENERATION CAPACITY IMPACT SOLAR CUSTOMERS?

A. The AED/4CP method used by TEP in the cost study recognizes that low cost energy results from higher capacity costs. Since solar DG customers use lower cost energy from the utility at night they should also pay for a portion of the fixed capacity costs of baseload units in order to buy the low marginal cost energy. While the AED concept was developed for cost allocation for full requirements customers it results in a more

appropriate allocation than would a CP methodology that allocates all capacity costs on a daylight peak hours. Whether the allocation is ultimately reasonable without modification is a fair question for review in rate case proceedings.

Q. HAVE YOU USED THE SAME DATA AND INTERNAL ALLOCATION FACTORS AS TEP?

A. Generally, the cost studies use the same data for revenue requirements and for allocation factors with the exception of creating a separate column for solar DG customers. We have also changed the use of the minimum system to classify costs. In the base study the solar customers' data and the full requirements customers sum to the same residential allocation factors in the TEP filed study. We have not calculated the revenues for each class and those have been excluded from the study so that the only information presented is the total cost based revenue requirements. For the other two studies the total revenue requirements remain the same and only the allocation factors for the solar DG customers have changed. In the counter factual study the customers are allocated the revenue requirement that would result from these customers being full requirements customers. This measures the cost shift between full requirements and partial requirements customers. This recognizes the practical reality of the zero sum nature of the cost study. Increasing the demands of solar DG customers result in lower costs allocated to all the other residential customers.

Q. PLEASE EXPLAIN THE CHANGE FOR THE CLASSIFICATION OF CUSTOMER COSTS USING THE MINIMUM SYSTEM.

A. In the TEP cost study TEP applied the classification for the minimum system to the costs after using the class NCP to allocate the distribution plant accounts. The use of NCP to allocate distribution plant accounts 364-368 under-allocates distribution plant to

residential customers and understates the customer cost component of unbundled rates. After making that methodological change the allocation differs from TEP even though the total revenue requirements remain the same. The result of this change is to allocate more costs to the residential class to reflect the impact of customers on the distribution system costs. It also impacts the unit customer cost component. This adjustment is consistent with the use of the minimum system method as discussed in the NARUC Electric Utility Cost Allocation Manual and the three step cost of service process of functionalization, classification and allocation.

V. ALLOCATION OF FIXED COSTS - RESULTS OF THREE STUDIES

Q. PLEASE SUMMARIZE THE RESULTS OF THE THREE FIXED COST STUDIES.

A. Table 2 below presents the different revenue requirements for full requirements residential and solar PV residential customers from the cost studies that are attached as Exhibit HEO- 5 Original Base Study, Exhibit HEO- 6 Counterfactual Study, and Exhibit HEO- 7 Solar Class Study. Each Exhibit provides the summary of the allocations and the revenue requirement for each class of service. The base study is identical to the filed TEP study with the exception that solar DG customers are treated as a separate part of the residential class. The counterfactual study assumes that solar DG customers were full requirements customers. The solar class study treats solar DG customers as if they were a separate class.

Table 2

Comparative Fixed Cost Revenue Requirements

Embedded Cost of Service Studies

Study	Residential Full	Solar DG Partial	Total Company
Base TEP	**$490,483,998**	**$10,386,841**	**$958,869,144**
Counterfactual	**$486,146,405**	**$14,724,434**	**$958,869,144**
Solar Class	**$489,591,785**	**$11,279,053**	**$958,869,144**
Lowest Revenue	**$486,146,405**	**$10,386,841**	

The results of these studies are useful in understanding that solar DG causes fixed costs that are significant. The total residential class fixed cost revenue requirement is the same $500,870,839 for the base, counterfactual and solar as a separate class cost studies. The difference in the studies relates to the intra class allocation.

The current annual rate revenue excluding Power Supply charges (the base revenue) for residential solar DG customers is $3,352,194. The subsidy may be calculated as the difference between the revenue and the base cost of service or $7,034,647. The implicit subsidy for fixed costs is just over $729[5] per customer for the 9645 solar DG customers on the lowest fixed cost allocation. That number increases to almost $822[6] when the actual solar class fixed costs are used. In addition to this subsidy, DG customers with net metering and banking have an additional subsidy based on energy costs as calculated in the following section.

Q. PLEASE EXPLAIN WHY THE THREE STUDIES ARE USEFUL.

A. Since cost of service is a zero sum methodology, all costs must go to some class and any

[5] Calculated as ($10,386,841 - $3,352,194)/9645= $729

[6] Calculated as ($11,279, 053 - $3,352,194)/9645= $822

change in allocation to one class must be reflected as an opposite change to one or more of the other classes. In order to understand the costs for residential DG customers, they must be separated from the full class. The portion of the residential class costs allocated to solar DG customers as part of that class are shown in the base study. The counterfactual study shows the amount of costs that would be allocated to full requirements customers prior to customers choosing to install solar DG and capture the benefits of net metering. Even though no changes occurred in the class cost and no changes occurred in the fixed costs[7] for utility service to the solar DG customers the solar DG customers are allocated less plant than would be allocated before they chose DG as shown by the counterfactual study. This result is not surprising since one would expect that these customers were larger on average than the average customer. Finally by treating solar DG customers as a class they still get less costs than when they were full requirements customers but the portion of plant allocated to them recognizes there higher class NCP based on delivering excess generation.

Q. IS IT POSSIBLE TO SHOW HOW COSTS CHANGED BY EACH UNBUNDLED COST CATEGORY?

A. Yes. Since the cost of service model develops unbundled costs it is possible to show the aggregate revenue requirements by unbundled cost components. Table 3 below provides the revenue requirements for full requirements customers and for Solar DG customers by function excluding energy.

[7] Solar DG customers still have the same distribution facilities and use the same baseload generation to serve night time loads.

Table 3

Comparison of Revenue Requirements by Function

Unit Cost Component	Base Case Residential RES	Base Case SGS SOLAR	Counterfactual Residential RES	Counterfactual SGS SOLAR	Solar Class Case Residential RES	Solar Class Case SGS SOLAR
Procurement						
Demand	$164,720,747.00	$3,638,609.00	$163,255,298.00	$5,104,057.00	$164,771,228.00	$3,588,128.00
Energy	$121,166,960.00	$2,480,688.00	$119,904,840.00	$3,742,809.00	$122,333,599.00	$1,314,049.00
MustRun						
Demand	$23,859,886.00	$516,489.00	$23,637,840.00	$738,535.00	$23,862,089.00	$514,286.00
Trans						
Demand	$53,895,819.00	$902,438.00	$53,145,395.00	$1,652,862.00	$52,741,699.00	$2,056,558.00
Distribution						
Demand	$45,115,282.00	$755,416.00	$44,487,115.00	$1,383,583.00	$44,149,188.00	$1,721,510.00
Customer	$55,808,488.00	$1,432,601.00	$55,808,488.00	$1,432,601.00	$55,808,488.00	$1,432,601.00
Customer	$25,916,817.00	$660,599.00	$25,907,429.00	$669,988.00	$25,925,495.00	$651,921.00
TOTAL						
Demand	$287,591,733.00	$5,812,952.00	$284,525,649.00	$8,879,037.00	$285,524,203.00	$7,880,482.00
Energy	$121,166,960.00	$2,480,688.00	$119,904,840.00	$3,742,809.00	$122,333,599.00	$1,314,049.00
Customer	$81,725,305.00	$2,093,200.00	$81,715,916.00	$2,102,589.00	$81,733,983.00	$2,084,522.00
Solar Revenue Requirement		$10,386,840.00		$14,724,435.00		$11,279,053.00

The table shows the embedded cost allocated to solar DG customers under each cost study. As would be expected the counterfactual cost study allocates more cost to solar DG customers because they are treated as full requirements customers. All of this data is useful because it shows the how solar DG customers shift costs to full requirements customers even though in the rate case period there are no changes in fixed costs associated with solar DG and ratemaking is based on cost of service.

Q. PLEASE PROVIDE THE CALCULATION OF THE COST SHIFT TO FULL REQUIREMENTS RESIDENTIAL CUSTOMERS FROM SOLAR DG CUSTOMERS ON AN EMBEDDED COST BASIS.

A. Table 4 below provides the cost shift based on the difference in revenue requirements for the base case and the solar class case from the counter factual cost study.

Table 4

Cost Shifts Resulting From Customers Adding Solar DG

	A	B
Unit Cost Component	Solar Class	Base Case
Procurement		
Demand	$1,515,929.00	$1,465,448.00
Energy	$2,428,760.00	$1,262,121.00
MustRun		
Demand	$224,249.00	$222,046.00
Trans		
Demand	-$403,696.00	$750,424.00
Distribution		
Demand	-$337,927.00	$628,167.00
Customer	$0.00	$0.00
Customer	$18,067.00	$9,389.00
TOTAL		
Demand	$998,555.00	$3,066,085.00
Energy	$2,428,760.00	$1,262,121.00

As would be expected, the AED allocation of production is lower and there is a larger embedded cost savings for solar customers when they are treated as a separate class. The energy cost shift results from the lower use of energy and hence a lower allocation of base costs allocated on energy such as fuel inventory costs. Two important factors

should be noted. As expected, treating solar as a separate class properly increases the cost of delivery related services based on the higher class NCPs from delivery of power to the system. There is also a slight increase in must run demand that is attributable to the variable nature of solar DG generation.

Q. WHY DOES THE SOLAR CLASS STUDY ALLOCATE MORE COSTS TO SOLAR CUSTOMERS THAN THE BASE STUDY?

A. The unbundled cost components are different based on the fact that the AED/4CP cost methodology allocates generation costs using a demand allocation factor made up of weighted average demand and weighted load NCP. The solar class allocation for generation is less than the allocation under the base case. For the demand related portion of the distribution system, the base case under allocates distribution system costs to the solar DG customers because it uses the load demand rather than the actual maximum demand which is based on delivery demand. The different NCP for delivery compared to the residential class coincident NCP for solar DG customers is less than half of the delivery NCP. That difference is based on the difference in the load diversity and the absence of diversity with respect to excess generation. Thus it is the delivery service that establishes the maximum demand on the distribution system. The net result is that the solar class's allocation increases compared to the base case.

Q. PLEASE DISCUSS THE COST OF SERVICE RESULTS.

A. Several conclusions are worth noting. First, the total full requirements, residential class, fixed cost of service is higher for the base case and the solar case than if the solar DG customers had not invested in DG. This results from a cost shift within the class to full requirements customers. Second, all three studies produce a customer charge for both full and partial requirements customers of about $18.00 per month. If the company were

to analyze the extra costs associated with solar DG associated with record keeping and billing it is likely that the solar DG charge would be above this average level. Third, it is critical to understand cost causation on the distribution system results in higher costs for solar DG even without the consideration of the added costs associated with lower power factor, more frequent voltage control events and other impacts on distribution system costs. Fourth, the evidence is conclusive that there are no avoided distribution costs for TEP and likely none for any utility in Arizona given the solar load shapes. Fifth, the magnitude of the base rate charges for solar customers would be much higher than the energy charges for full requirements customers thus necessitating recovery of the fixed charges in demand charges because the kWh charge under a two-part rate would further distort the solar DG sizing decision.

Q. WHAT CONCLUSIONS DO YOU REACH FROM THE COST OF SERVICE STUDIES AS THEY RELATE TO SOLAR DG, NET METERING, BANKING AND RATES?

A. The conclusions related to cost of service are as follows:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers who have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately (the ACC has made a good start on unbundled rates by identifying delivery services and power supply charges but more needs to be done in particular

removing all fuel and variable generating costs from base rates and recovering those costs on a time of use basis) and the rate design must be a multi-part rate to meet the principles of cost causation and matching.

Q. WHICH COST METHODOLOGY SHOULD BE USED IN FUTURE RATE CASES TO PROMOTE EQUITABLE RATES TO CONSUMERS?

A. Solar DG residential customers have very different usage characteristics as compared to full requirements residential customers. That is the two groups are not homogeneous and thus need to be treated as separate classes in the cost study. Going forward, the solar residential customers should have rates based on the costs they cause. They should also have separate load research for both load and generation to precisely measure the system impacts of both delivery and production. The minimum system method for classifying distribution customer costs should be used to properly reflect costs caused by customers regardless of load. Setting rates based on costs also means that it is important to send these customers a price signal that creates value for smart inverters. Thus, the demand charges for these customers should be based on kVa rather than kW.

Q. DOES THIS RECOMMENDATION ALONG WITH UNBUNDLED RATES HAVE ANY NEGATIVE IMPACT ON THE CONSERVATION OF ENERGY SUPPLIED BY THE UTILITY?

A. No. On the contrary the unbundled rates that reflect cost causation actually result in more efficient conservation of utility energy and capacity than the current tiered rate structure. The tiered two-part rate results in energy cost savings to the customer that are far more than the actual savings to the utility. As a result, utility resources are misused resulting in lower energy consumption but also lower savings in capacity. This actually works against the efficient use of resources contrary to the very definition of conservation which

is defined as "Exploitation, improvement, and protection of human and natural resources in a wise manner, *ensuring derivation of their highest economic and social benefits on a continuing or long-term basis.*"[8] (Emphasis added.) The unbundled rates based on marginal costs to the extent consistent with revenue requirements represent the best option to promote conservation efficiently. Further, using rates based on this cost of service study, eliminating both net metering and banking, using a monthly avoided cost cashout for excess energy or in the alternative using a buy all sell all that has a current avoided cost value of solar will provide the most efficient platform for integrating solar DG into the utility supply portfolio.

Q. DO THE UNBUNDLED RATES RESULTING FROM THE COST STUDY PROVIDE RATES THAT ARE JUST AND REASONABLE AND NOT UNDULY DISCRIMINATORY?

A. These rates meet the just and reasonable test for rates and treat customers with the same load characteristics equally. That does not occur under two-part even if the class is relatively homogeneous. The reason is straight forward. The energy under current rates recovers customer costs not recovered in the customer charge on a per kWh basis meaning that any customer with annual usage larger than the average pays a higher share of the customer costs and subsidizes customers who use less than the average. A similar issue relates to the recovery of demand related costs which are spread to the kWh charge based on the class average load factor. Any customer, large or small, with a better than class average load factor pays a larger share of the demand related fixed costs while lower load factor customers pay less than the costs they cause. It is not unusual for residential load factors to vary significantly with the lowest load factors being less than half the highest load factors. Based on the UNS Electric load research data, the NCP load

[8] http://www.businessdictionary.com/definition/conservation

factors differ for subgroups of the residential customers ranging from about 19% to 49% per subgroup. For a five dollar cost per kW per month, the low load factor charge per kWh would be $0.036 per kWh while for the highest load factor the charge would be $0.014 per kWh or about 39% of the charge for that lowest load factor subgroup. Using a demand charge and a cost based customer charge eliminates this difference. I should also note that the tiered rates implicitly assume that load factor declines with increasing kWh usage. In fact, the opposite is the case as larger use customers have higher load factors than lower use customers on average. This means that there are also intraclass cost subsidies in current rates.[9]

VI. ALLOCATION OF ENERGY COSTS - COMPARISON OF RESIDENTIAL FULL AND PARTIAL REQUIREMENTS CUSTOMERS

Q. WHY IS IT NECESSARY TO ALLOCATE ENERGY COSTS OUTSIDE THE COST OF SERVICE STUDY?

A. In a traditional cost of service study the basic assumption is that all classes use energy in the same pattern as the system with the only differentiation in the level of losses associated with voltage level of service. While this assumption may not be matched for each class of service, there is no systematic difference within a class of customers. The customers with solar PV under net metering with banking use energy far differently than full requirements customers. To understand this issue we only need to look at the difference in the system load pattern and the output of solar DG. Exhibit HEO – 1 illustrates how solar output does no match the system load profile. Instead, solar output is most likely to be at its maximum in lower load periods. While the correlation of load and cost is not perfect, the solar production is lower than rated capacity or zero in some

[9] This is also consistent with findings in California related to intra-class cost subsidies under inverted rates.

of the highest cost periods and is highest in some of the lowest cost periods. This means in the low load periods when solar meets the customers' requirements and sends excess energy back to the system the value of that energy is lower than in some high load, high cost periods when solar customers must rely on the grid to supplement the energy produced by the solar DG. If this issue was only consumption at night when costs are lower the matching between the costs imposed at night and when the power is returned to the grid there would be better matching of costs after adjusting for losses. That is not however the sole issue. Simply, the average marginal cost in non-solar hours is actually greater than the average marginal cost when solar is operating. Given the unique and coincident patterns of solar DG there is also a mismatch of avoided costs and average costs that allows for arbitrage through storage that results in additional cross subsidy for the energy component of costs. The arbitrage subsidy is potentially significant and cannot be evaluated through the embedded cost study since it only deals with average costs. There is even a subsidy in the difference between the average cost of energy and the lower marginal cost avoided when solar customers use their own generation. The largest subsidy is related to the full cost reimbursement for excess as compared to the avoided marginal costs.

Q. DOES THE SEPARATE ENERGY COST ANALYSIS ALLOW FOR AN ASSESSMENT OF THE UNIQUE SOLAR LOAD PATTERNS IMPACT ON THE EFFICIENT OPERATION OF THE UTILITY GENERATION?

A. It does to the extent that the system has enough solar load and output to actually track the ramp rates and other operating requirements. In any event, the energy cost study allows for an analysis of avoided costs and the actual average cost for solar load as compared to full requirements customers. This is useful for assessing the actual energy related subsidies included in the energy component of rates.

Q. HAVE YOU PREPARED AN EXHIBIT THAT PROVIDES THE RESULTS OF THE ENERGY COST STUDY?

A. Yes. Exhibit HEO – 8 Energy Cost Study is attached. That exhibit uses hourly loads and hourly marginal costs to calculate avoid costs for solar DG customers, marginal costs for full requirements load, and the energy cost subsidies that result from net metering. The study uses actual 2015 billed data from TEP solar customers along with 2015 hourly marginal and embedded costs by hour to make the calculations.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ENERGY COST STUDY.

A. The energy cost study shows nearly $1.4 million dollars of energy cost subsidies that result from energy arbitrage (buying higher marginal cost energy and returning the energy in lower marginal cost periods), energy excess sale (selling excess energy back to the company at average energy cost when marginal cost is less than the average cost) and energy credit for solar DG used on premise (the difference between the average power costs and the marginal avoided power costs). The total subsidy for these three subsidies is $144.72 per solar DG customer. These subsidies are also significant larger than one would expect from using average energy costs within relative homogeneous class of service.

Q. PLEASE EXPLAIN HOW THE ENERGY SUBSIDY FOR EXCESS GENERATION WAS CALCULATED.

A. The calculation is a three-step process. In the first step the marginal hourly energy cost for load is calculated ($26.97 per MWh). In the second step the marginal avoided cost of excess energy is calculated ($24.62 per MWh). The net of these two values is the arbitrage associated with consumption in high cost hours with no adjustment for losses in the measurement of the excess energy. The full energy subsidy may be calculated in step

three as the difference between marginal energy cost of load ($26.97) and average system hourly energy costs for the excess energy component ($42.39 per MWh) plus previously calculated arbitrage value. Exhibit HEO – 8 Table 2 provides the calculations for average hourly marginal cost.

Q. WHAT CONCLUSIONS FOLLOW FROM THIS ANALYSIS?

A. This analysis confirms and supports the conclusions related to solar DG, net metering, banking and rates above. Net metering results in large and persistent subsidies that cannot be justified particularly when solar DG is not the least cost solar power option.

VII. SOLAR DG BENEFITS - NEAR TERM AND LONG TERM DIFFER

Q. WHY IS IT NECESSARY TO DISTINGUISH BETWEEN NEAR TERM AND LONG TERM BENEFITS?

A. For cost studies and for rates regulators use a test year to determine revenue requirements based on cost of service. Thus a rate case may be characterized as a near term analysis. In an IRP analysis or in a long term contract benefits are evaluated over a long term horizon but variable rates are not set on that long term forecast. The result is that it is necessary from an economic and efficiency basis to consider benefits and their rate impacts as in the near term context. In essence the fundamental problem with the avoided cost rates used in PURPA contracts in the 1980's was the levelization of both the fixed cost component (avoided capacity costs) and the forecast and levelization of future energy costs into a single payment stream. The PURPA contracts had oil as the marginal fuel in the Northeast and oil prices at over $100 per barrel as early as the 1990s. These oil prices did not materialize and gas became the marginal fuel resulting in avoided costs far below the fixed price payments in these contracts. The simple solution for just and

reasonable rates is to separate the components. The energy component should be based on the short term test year marginal costs that underlie the test year revenue requirements. The capacity avoided costs are by their nature long-term costs and those should be based on the net present value of the avoided costs in the future. For solar DG the avoided capital cost in any year will vary with the expected long-term growth of the utility, technological changes in the alternative sources of power including solar options, the impact of storage technology on avoided capacity costs and so forth. From an economic perspective net metering with or without banking cannot adequately address these issues. There is no reason to believe that marginal costs are correlated with the average costs that make up revenue requirements for at least the following reasons:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the system are lumpy and as a result utilities optimal additions often include more capacity than the marginal change in the variables that reflect cost causation such as customers, CP demand, class NCP demand and customer NCP demand.

Given these factors even a sound and efficient multi-part rate cannot adequately reflect the avoided capacity related costs. A properly developed marginal cost based seasonal TOU energy charge will result in a better matching of energy costs and benefits with in the rates and creates no need to include future costs that are highly uncertain as part of the current price signal. By including the future costs of energy in the analysis of current

benefits there is an intertemporal subsidy that provides no benefit for current full requirements customers but rather results in social welfare losses for all non-DG customers in the current period.

For the avoided capacity cost component, if any, those costs should be fixed at the time the solar DG is added to the system and established in a tariff provision that applies to the particular vintage of installations. The avoided DG capacity payment would be most efficient if it were determined by a market process such as competitive bidding for DG capacity in a tranche. The solar DG would bid a capacity payment for the peak hour or hours output of the facility. The winning bids would be certified by the utility as at or below the avoided capacity costs. The regulated version of this process would be an annual avoided cost determination hearing and setting the rate at the avoided cost. In either case the rate would be fixed for the 20 year life of the facility. Obviously, this latter method is less efficient since it is a fixed price and not a competitive bid price that would result in the least cost options for customers and promote bidders seeking to be more efficient and productive to maximize their return.

Q. HOW WOULD A CAPITAL CREDIT WORK IN PRACTICE?

A. The capital credit would be assigned to the premise and paid annually based on the amount bid or the amount calculated at the time of the contract with a stream over the entire period of the contract. As a practical matter this is the same pattern of costs for a utility developed asset. It also requires that the solar DG produce output for the term of the contract or lose the capacity payment just as a utility would lose rate base treatment for an asset no longer used and useful for a utility. The payment of a levelized total cost is inconsistent with rates and creates issue of intergenerational equity and potential excess payments since solar DG has no obligation to operate at rated capacity over its useful life. In fact capacity values will decline over time. Further, there is no guarantee that current

solar will be operating over its useful life and no obligation on the part of a solar DG customer to make the necessary repairs to maintain the capacity particularly when the premise changes ownership. This all suggests that capacity payments, if any be made separately from retail rates and not be the result of net metering which causes both excess payment for the solar DG in the near term and even over the useful life as the value of DG declines as penetration increases and as the asset ages.

Q. WHY IS THE DISTINCTION BETWEEN LONG TERM BENEFITS AND SHORT TERM BENEFITS PARTICULARLY IMPORTANT IN SETTING POLICY FOR SOLAR DG?

A. This distinction is critical to the fundamentals of competitive market outcomes, economic efficiency and just and reasonable, non-discriminatory rates. One of the purposes of regulation is to recognize that competitive market outcomes cannot result from services that are best provided by a monopoly service because of scale economies. As noted above, the provision of utility service is best provided in a mixed monopoly and competitive model. As a result of this new model the monopoly portion of the model should only be the wires component of the utility for a fully unbundled utility with no provider of last resort or balancing authority requirements. Generation is a competitive self-service option and solar generation in any form must compete with conventional generation and with other renewables and even different types of solar projects to be part of the least cost mix for meeting state mandated renewables goals. The solar generation alternatives are numerous and use different technologies that should be considered in a competitive market not a market supported by subsidies that bear no relationship to economically efficient marginal cost based price signals.

The only way to provide for efficient outcomes is to separate the capital and the energy components of the payment stream. Energy payments based on short run costs is the

exact same way that utility generation recovers energy costs. Over the life of some power plants that energy cost moves up and down with competitive input prices. There is no economic reason that solar DG should be any different than a competitive power plant that bears the fuel cost risk in the short term. Further, the capital cost payment based on the avoided cost at the time of the contract is the intrinsic economic cost of capital over the life of the asset. This mixture on short term energy and long term capital will allow both customers and society in general to benefit from an economically efficient mix of generation resources.

VIII. THE OUTCOME FOR NET METERING MUST MEET THE OBJECTIVES OF PURPA

Q. PLEASE EXPLAIN HOW THE PURPA OBJECTIVES ARE RELATED TO NET METERING.

A. Subtitle A of PURPA provides general provisions that are tied to the Retail Regulatory Policies for Electric Utilities in Title I of the original Federal statute. The net metering provision amended Section 111 (d) that established certain standards for review subject to the full requirements of Section 111 Consideration and Determination Respecting Certain Ratemaking Standards. The Energy Policy Act of 2005 amended Section 111 (d) to provide for three new standards for consideration including a net metering standard. Section 101 Purposes of the law was not amended during the process of amending Section 111 on several occasions including the amendment that added net metering. The Purposes of the law are as follows: "to encourage (1) conservation of energy provided by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates to electric consumers. Section 111 (a) Consideration and Determination provides that approval of the standards must consider whether adoption of the standards

carries out the "purposes of this title". Those purposes for the title are contained in Section 101 as noted above. Thus Section 111 (a) sets the standard for review for Section 111 (d) as it relates to the purpose of PURPA. Neither Section 101 nor Section 111 (a) has been amended with respect to net metering. Section 111 (a) also notes that the Section supplements applicable state law. Thus net metering must meet the purposes of PURPA, the most important of which in this context is equitable rate for consumers since this is a ratemaking concept. It is also important that the other two purposes be evaluated as a matter of policy. Thus any decision related to net metering must identify how these purposes are met.

Q. PLEASE DISCUSS THE EQUITABLE RATES PROVISION.

A. Equitable rates are not defined in PURPA. However, the concept has been defined over the years by regulators, legislators and the courts with terms like just and reasonable rates, non–discriminatory rates and rates that manifest the cost causation principle and the matching principle noted above. Where rates reflect cost causation it is reasonable to conclude that the rate is equitable. In the context of net metering rates are equitable only if the rate design reflects cost causation and the value of the solar energy produced matches current avoided costs for the rate effective period.

Rates for the monopoly portion of the services required by solar DG must be fully unbundled and designed so that when a customer chooses to use a monopoly service the customer cannot avoid any of the fixed costs caused by the customer's choices of services. Obviously, net metering with volumetric recovery of fixed costs cannot produce equitable rates. When kWh banking is allowed the mismatch of avoided costs and net metering credits is further exacerbated because the energy costs when the customer consumes supplemental power is during high load periods and when solar DG cannot produce power. The hours when solar cannot produce power include both low

load and lower cost periods in the summer and part of the winter. In other winter hours solar DG is not available in higher cost periods and uniformly produces maximum output for delivery to the utility in low load and low cost periods. The net result is, as discussed above, solar DG virtual storage arbitrage from both the timing of excess deliveries and the failure to account for the extra losses under this transaction.

Q. DO THE NET METERING PROCEDURES ADOPTED BY THE ACC COMPLY WITH THE EQUITABLE RATES PURPOSE OF PURPA?

A. There are inequities in all of the transactions that occur under net metering. Specifically, solar DG customers pay a lower portion of the fixed costs of the unbundled services they use than do customers who use the same unbundled services in a full requirements service package. Solar DG customers are also likely to have higher costs than their full requirements counterparts because of costs they cause that are not tracked such as higher losses from the low power factor, the impact on system dispatch particularly related to ramp rates and higher spinning and operating reserves, and the higher losses they cause during low load periods. For recovery of fixed costs associated with delivery service, the kWh rate with a low fixed charge under recovers costs for solar PV as well. In sum, the current arrangement does not produce equitable rates.

Q. PLEASE EXPLAIN THE PURPOSE OF OPTIMAL EFFICIENCY OF ELECTRIC UTILITY FACILITIES AND RESOURCES AS IT RELATES TO NET METERING.

A. It is difficult for solar DG to use a system designed solely for delivery of power from higher voltage transmission to lower voltage delivery service levels to use the current resources efficiently. Instead, the issue should be addressing these issues in optimal efficiency related to a reconfigured, least cost system. For example, where the costs for

upgrading the system can be avoided by interconnection requirements, solar DG customers should bear these system related costs. This could include for example requiring smart inverters for all DG facilities. It would also require a provision that where excess generation causes higher transformer loadings or more flexible transformers solar customers should pay those higher costs. Where the system must invest in facilities to use the sunk cost portion of the system efficiently those costs should be directly assigned to the solar class of customers. Efficient use of resources must also address the generation mix issues ultimately in determining the least cost efficient configuration of the system.

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. I reach the following conclusions based on the evidence I have provided:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers because they have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately and the rate design must be a multi-part rate to meet the principles of cost causation and matching.
5. The solar DG subsidy for TEP is currently more than $8 million and if solar is treated correctly as a separate customer class the subsidy is over $9 million.

6. The maximum demand of solar customers on the utility system occurs in March or April when solar DG pushes kWhs back onto the system with no natural time diversity.
7. Current rate treatment for solar DG does not produce equitable rates for all customers.
8. There are more efficient, least cost renewable energy resources available other than rooftop solar DG and rooftop should compete with those resources.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

1. Utility cost studies should be filed to include solar DG as a separate class of service.
2. Cost studies should use the minimum system to develop the unit customer costs to be recovered in the customer charge.
3. The NCP allocation factor for solar DG customers should be the greater of the load or the delivery NCP to reflect the maximum demand on delivery resources.
4. Both sales to customers and delivery from customers should be adjusted for losses.
5. Markets should be used to determine the value of DG resources since self-generation and power purchases from DG and utility scale resources are competitive options.
6. All customer rates should be properly designed multi-part rates that recognize cost causation for unbundled services.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Attachment A

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc.,

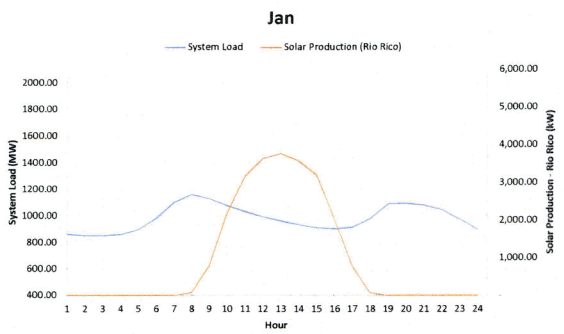
the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

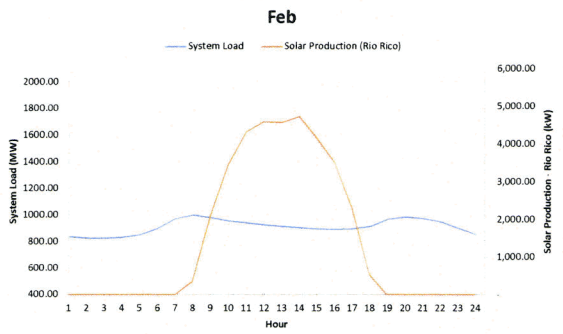
Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director of Black and Veatch Management Consulting, LLC.

Exhibit HEO - 1


Jan
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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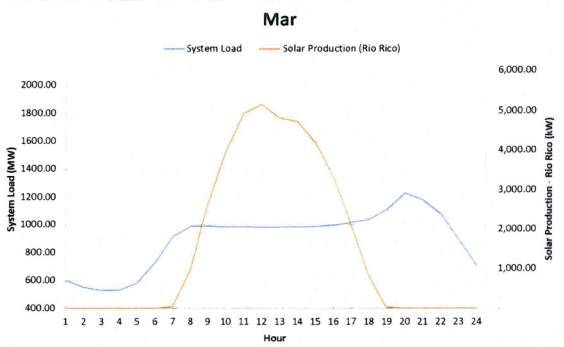
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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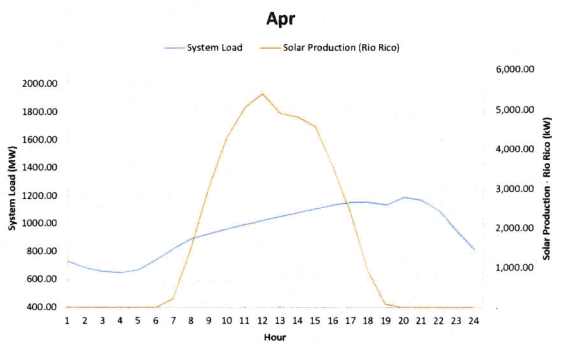
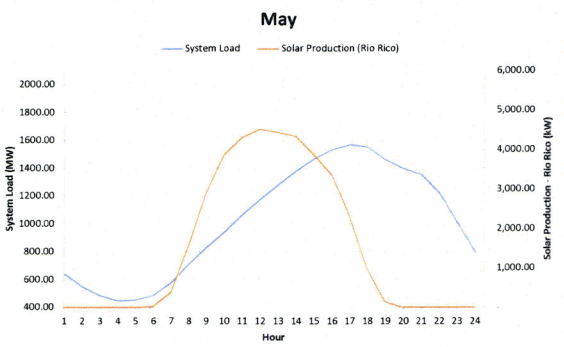
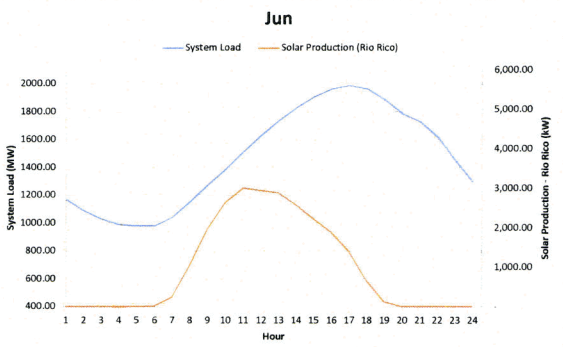
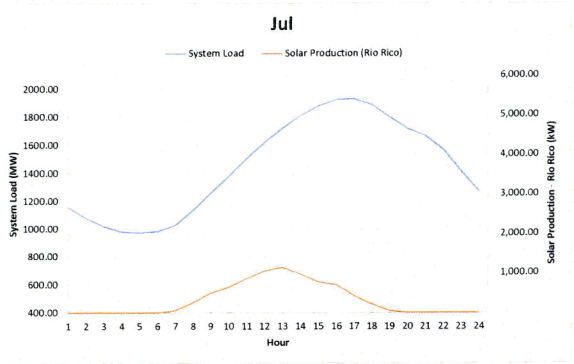
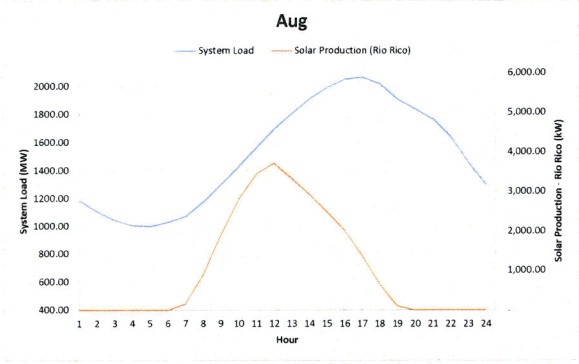
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

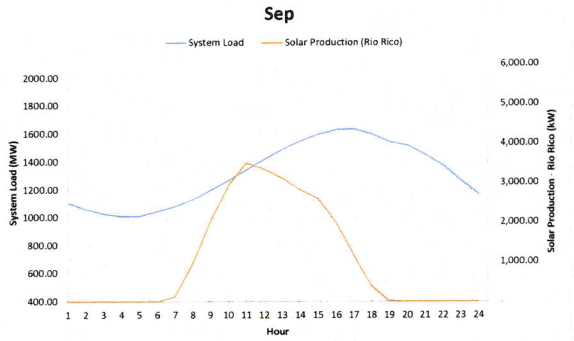

Apr
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

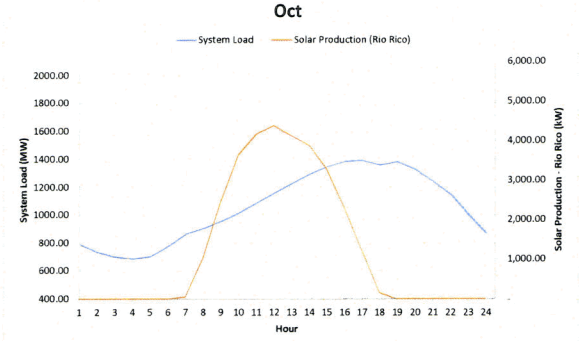

May
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

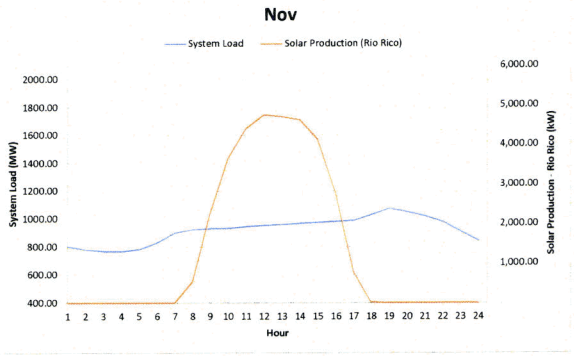

Jun
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Jul
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Aug
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Sep
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Oct
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Nov
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

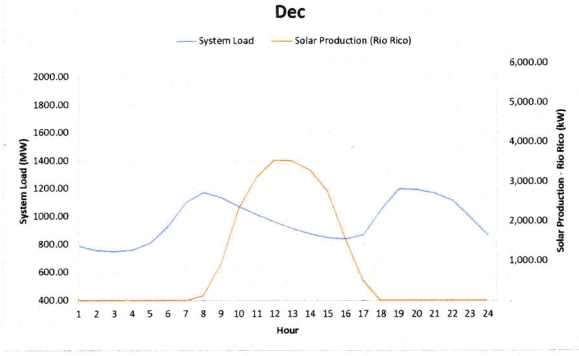
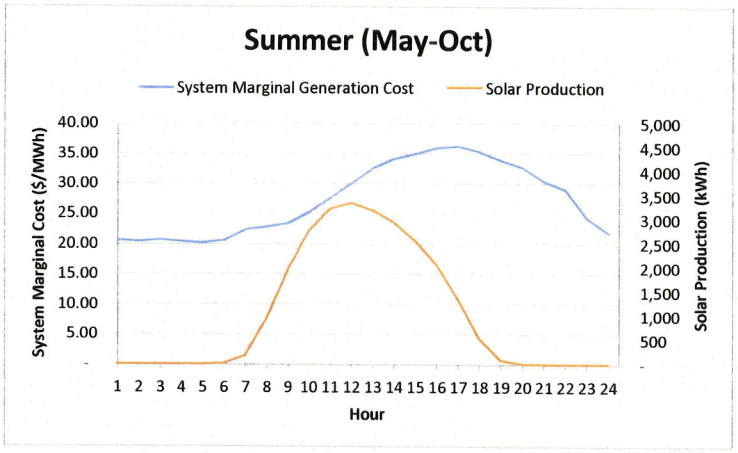

Dec
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

Exhibit HEO - 2


Summer (May-Oct)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

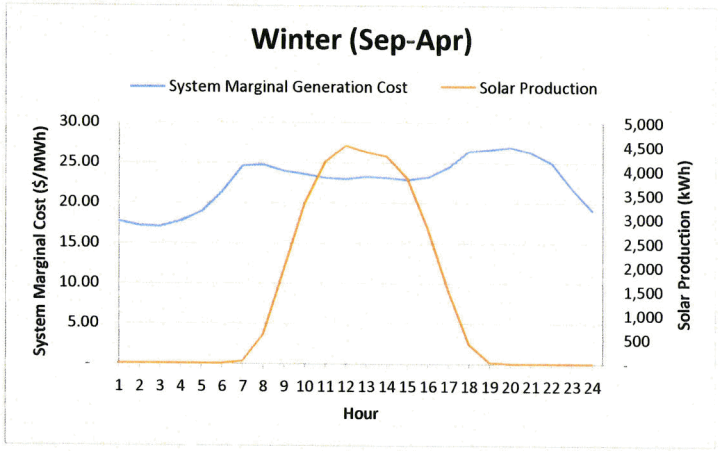

Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Exhibit HEO - 3

Distribution Planning and Engineering

Residential Solar Generation Losses Memorandum

To: Jones, Craig; Dukes, Dallas;

From: Brandon Knight/Nate Palma

CC: Bustamante, Ana; Lindsey, Chris; Sandoval, Donovan; Fleenor, Chris; Taylor, Jim

Date: February 3, 2016

Re: Residential Solar Generation Loss Study

Background

Residential Solar Generation installations are becoming more prevalent on TEP's power distribution system and like all generation, losses account for a portion of the production within TEP's system. Typically, solar can reduce losses during high demand times by lowering transformer loading and reducing current but there are times when solar does the opposite and can increase loading on a transformer. The highest values of losses associated with residential solar generation occur when the distribution system's demand is at noon peak and solar production is at its noon peak.

During the month of March, the demand on TEP's distribution network is at its minimum. Solar production peaks have been documented to reach its peak production at 12pm. Therefore, the data from 20 feeders (small sample size) within TEP's distribution system was analyzed over the entire month of March at 12pm to determine the typical residential transformer loading to determine the average consumption of each house in a typical network configuration. The configuration for these loss approximations is the same example given to Black and Veatch for the TEP Rate Case with these standard assumptions: 1) all cable is 1/0 underground 2) eight homes served off a 50 kVA transformer 3) cable lengths of 400' primary cable connecting each transformer, 100' of secondary cable connecting to each pedestal, and 75' of service cable connecting to the customer/meter.

TEP has outlined three cases to demonstrate the losses of solar generation on TEP's distribution system. Each case uses the typical network configuration of 8 homes on a single 50 kVA transformer; TEP will illustrate in each diagram in the pages to follow the amount of rooftop solar that either 1, 2, or 3 houses produce (7 kVA of generation apiece). Transformer loading percentages are a good indication of whether losses will be higher or lower at any given time. If a transformer is lightly loaded, there will be less current flowing across the line. Therefore, when load is much lower, the solar generation

production can actually increase the loading percentage of the transformer and increase the losses on the system.

Solar generation losses on the system were approximated using the cable impedances along with the typical transformer impedance values, and the associated current along each branch. The current was approximated using the typical demand values for each house found in March at 12pm, and the kVA on each branch due to generation.

Typical loading in March at 12 PM with no Solar Generation

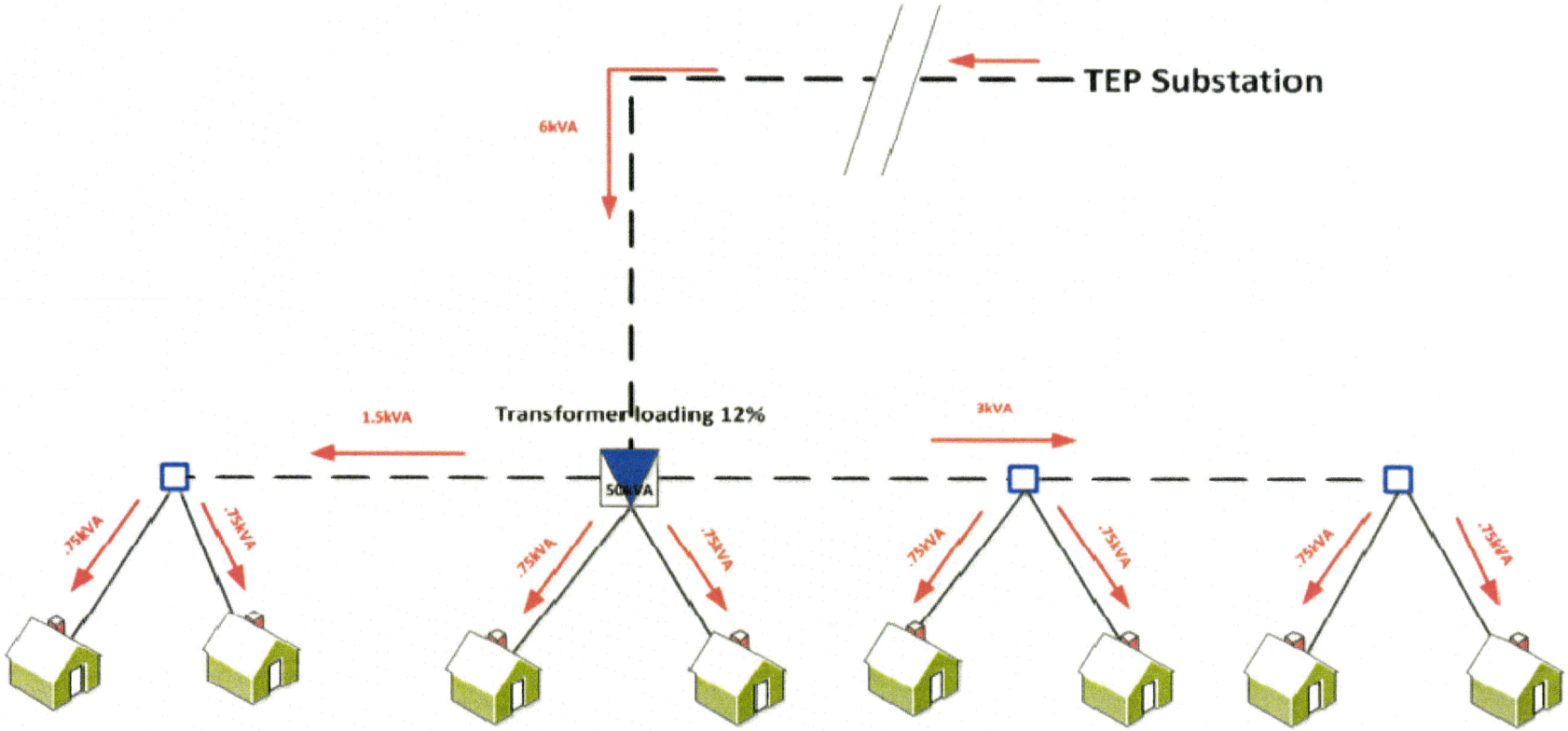


Exhibit 1

Exhibit 1 is the typical residential configuration present within TEP's distribution system. This configuration consist of 8 residential customers being served from a 50kV transformer. To find the average loading of the transformer in March at 12pm where solar production would be at its peak, DP&E collected data from 20 feeders. The average loading of the transformers at this time was found to be 12%.

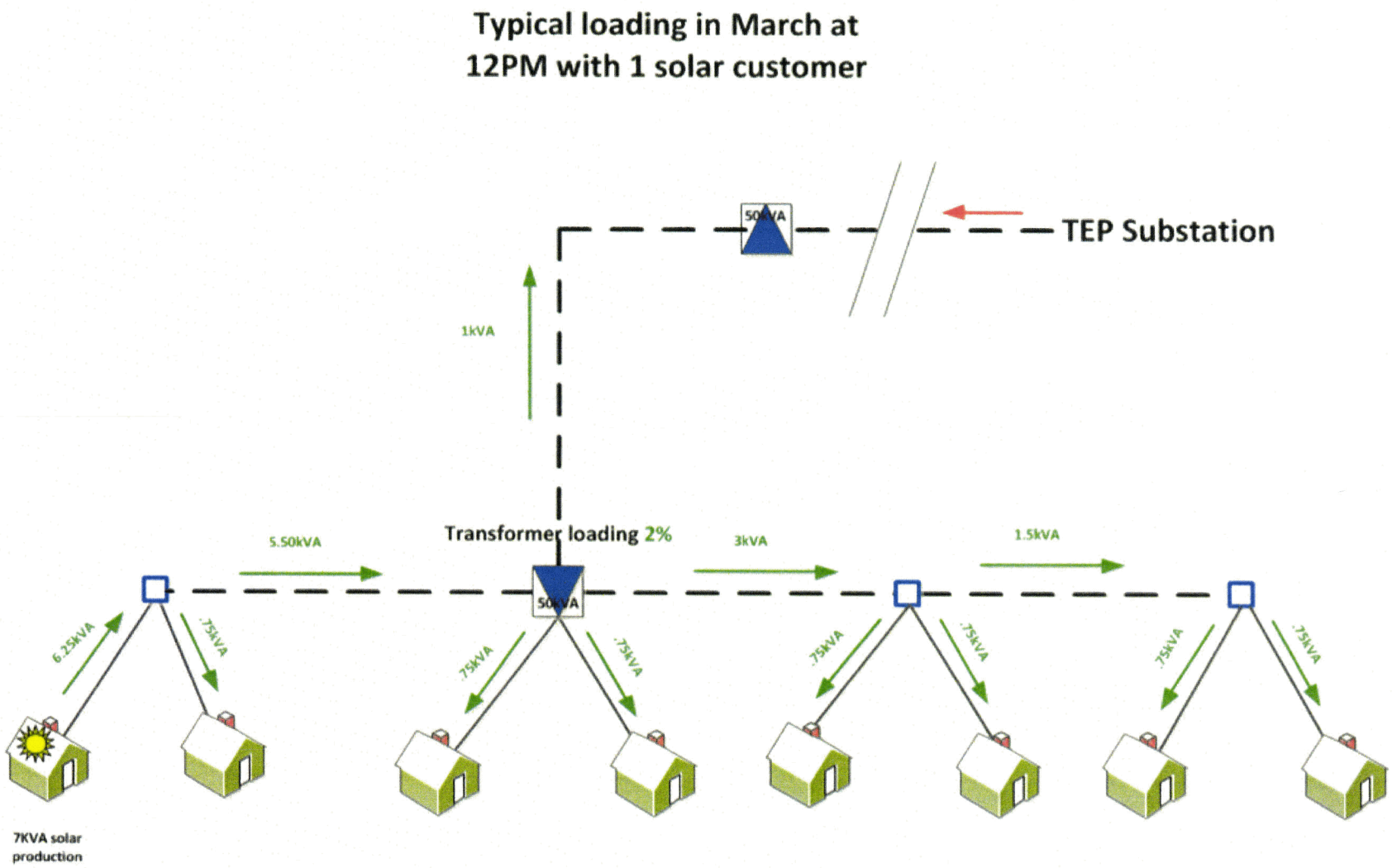
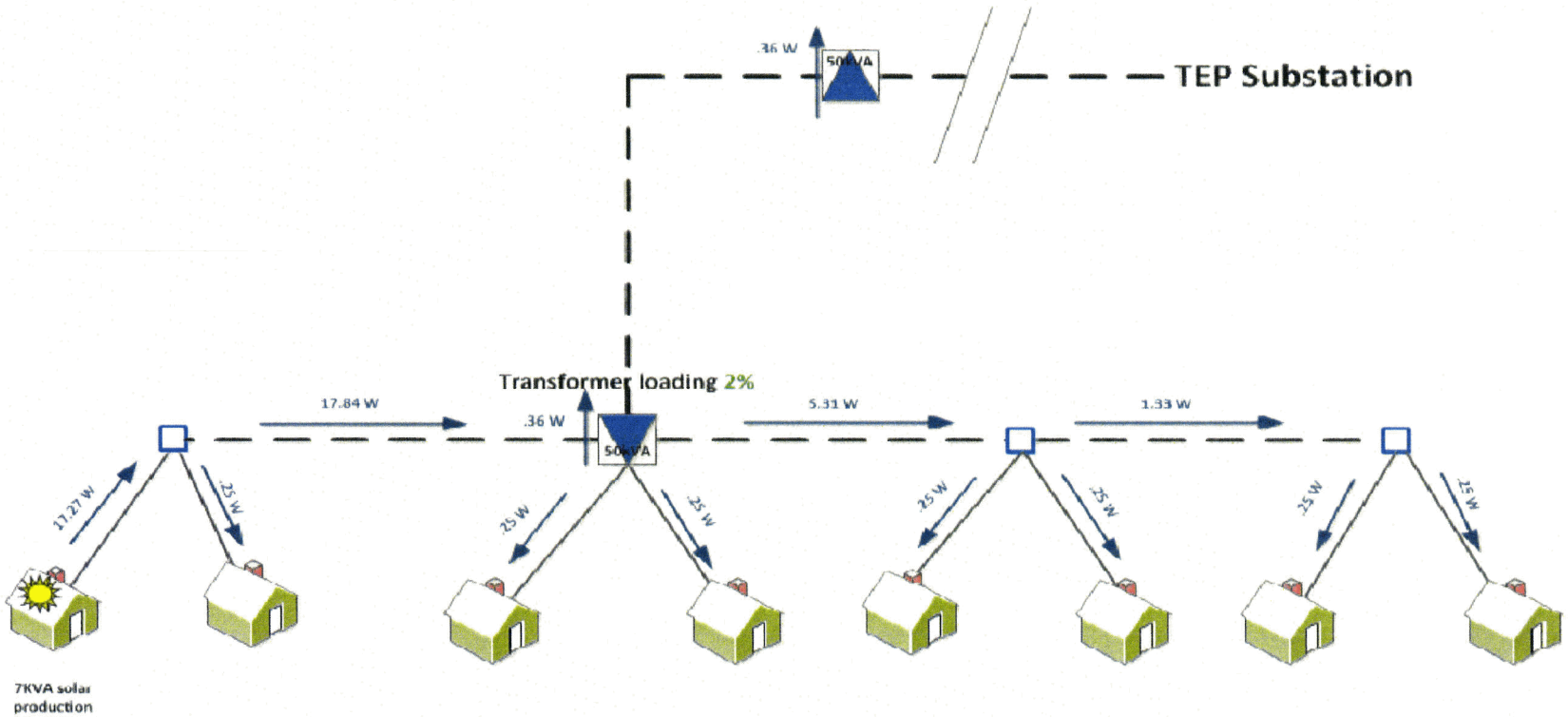


Exhibit 2

Exhibit 2 demonstrates the effects one house with solar generation can have on TEP's system. The green power flow arrows are the results of 7kVA of residential solar generation.

Solar Generation losses associated with 1 house producing 7kVA at daytime minimum



Total Solar Generation Losses = 44.20W

Exhibit 3

Using the typical transformer impedance and line impedance of this configuration, losses from the solar generation were calculated. The formula used for the loss calculations was $P=I^2R$ where I is the amps across and R is the magnitude of the impedance.

Typical loading in March at 12PM with 2 solar customers

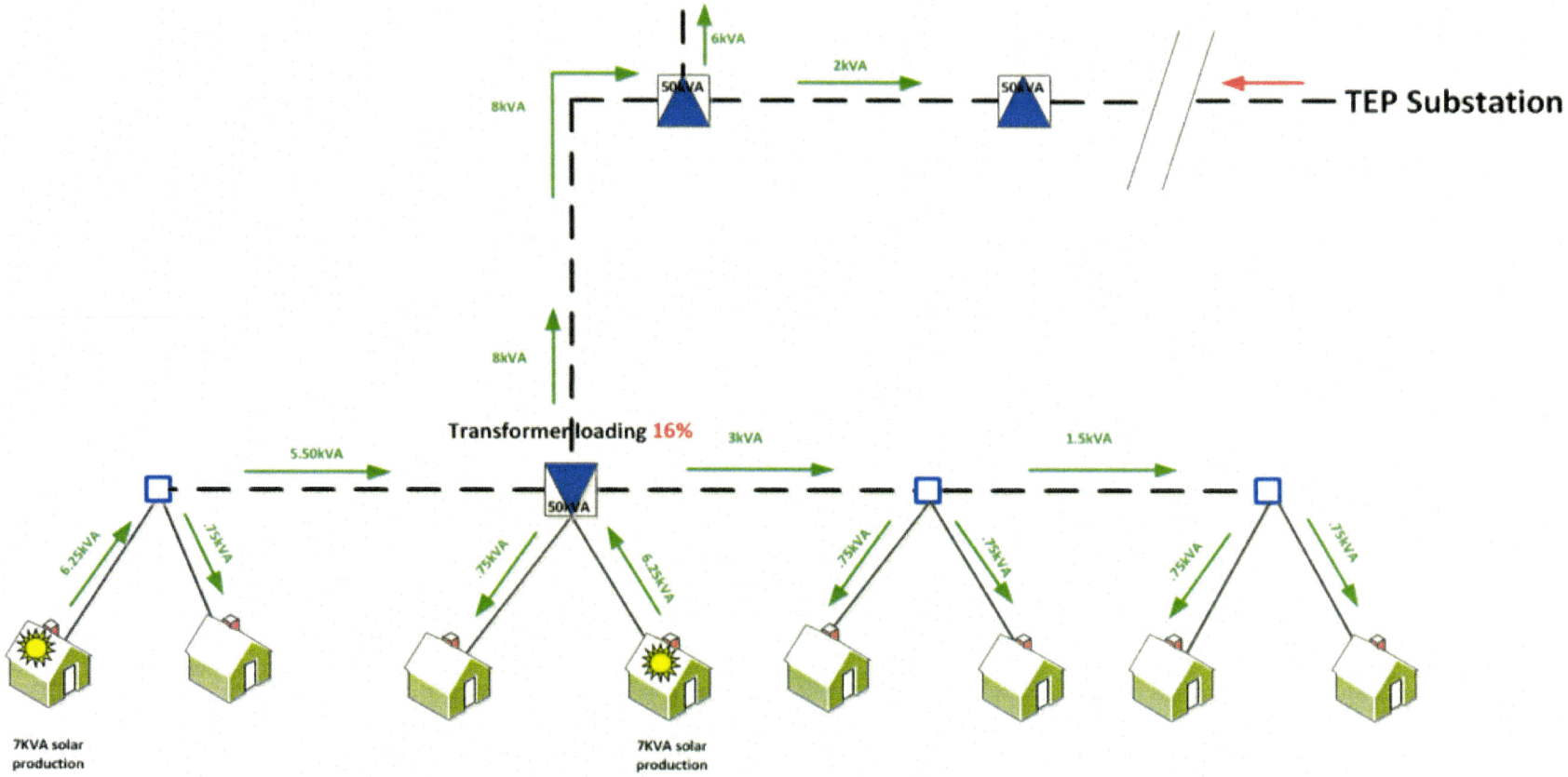
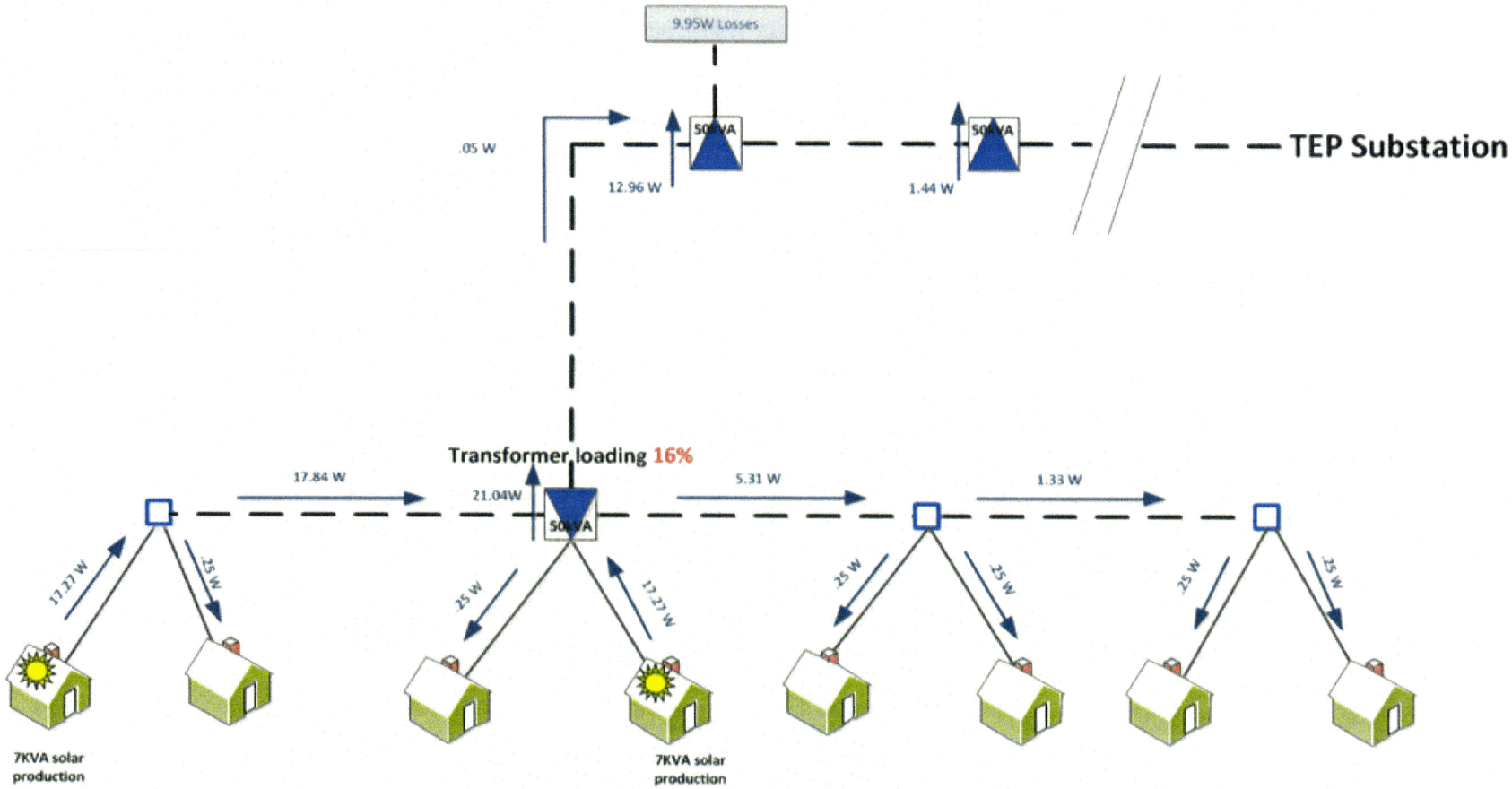


Exhibit 4

Solar Generation losses associated with 2 houses producing 7kVA at daytime minimum



Total Solar Generation Losses = 107.95W

Exhibit 5

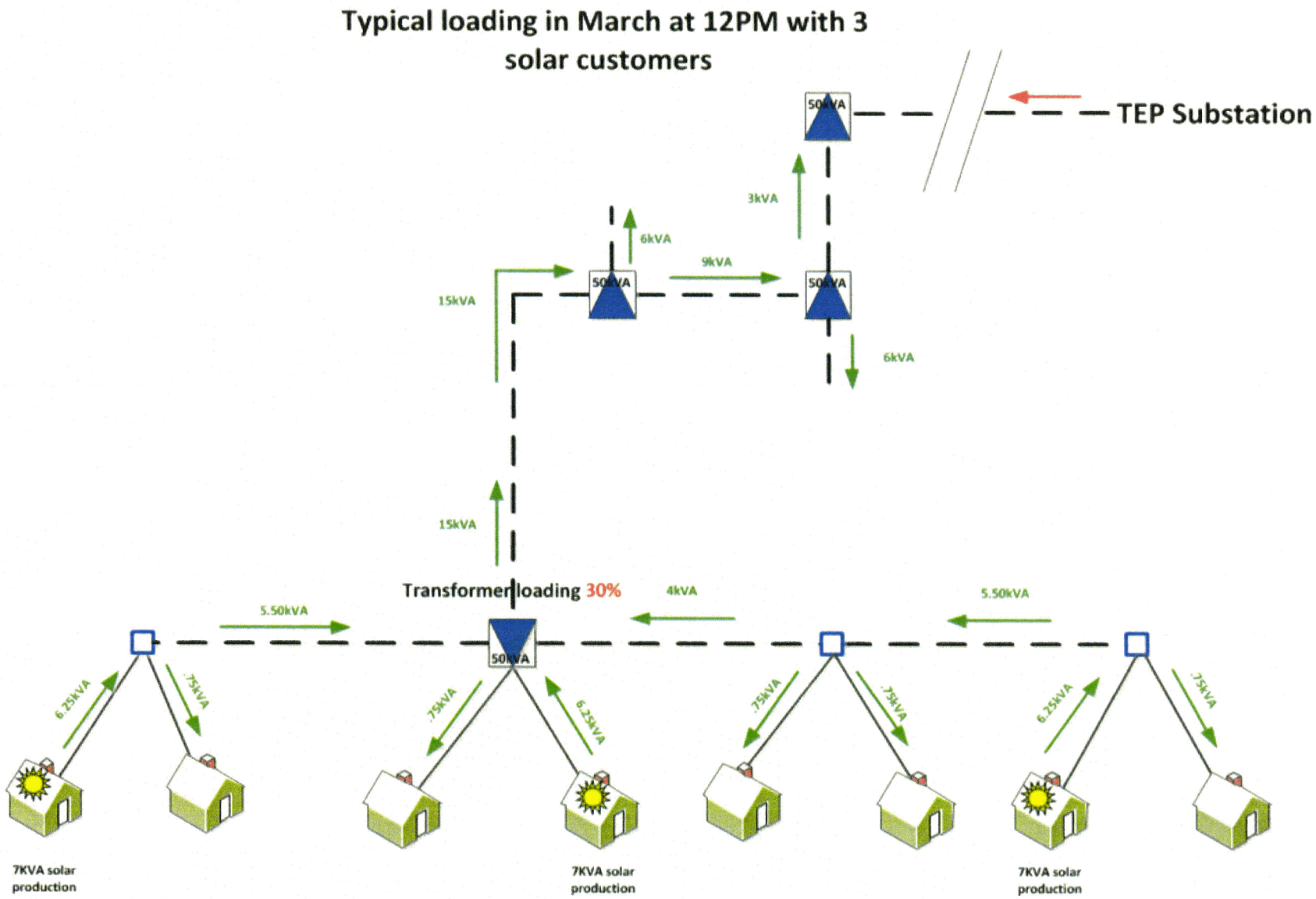
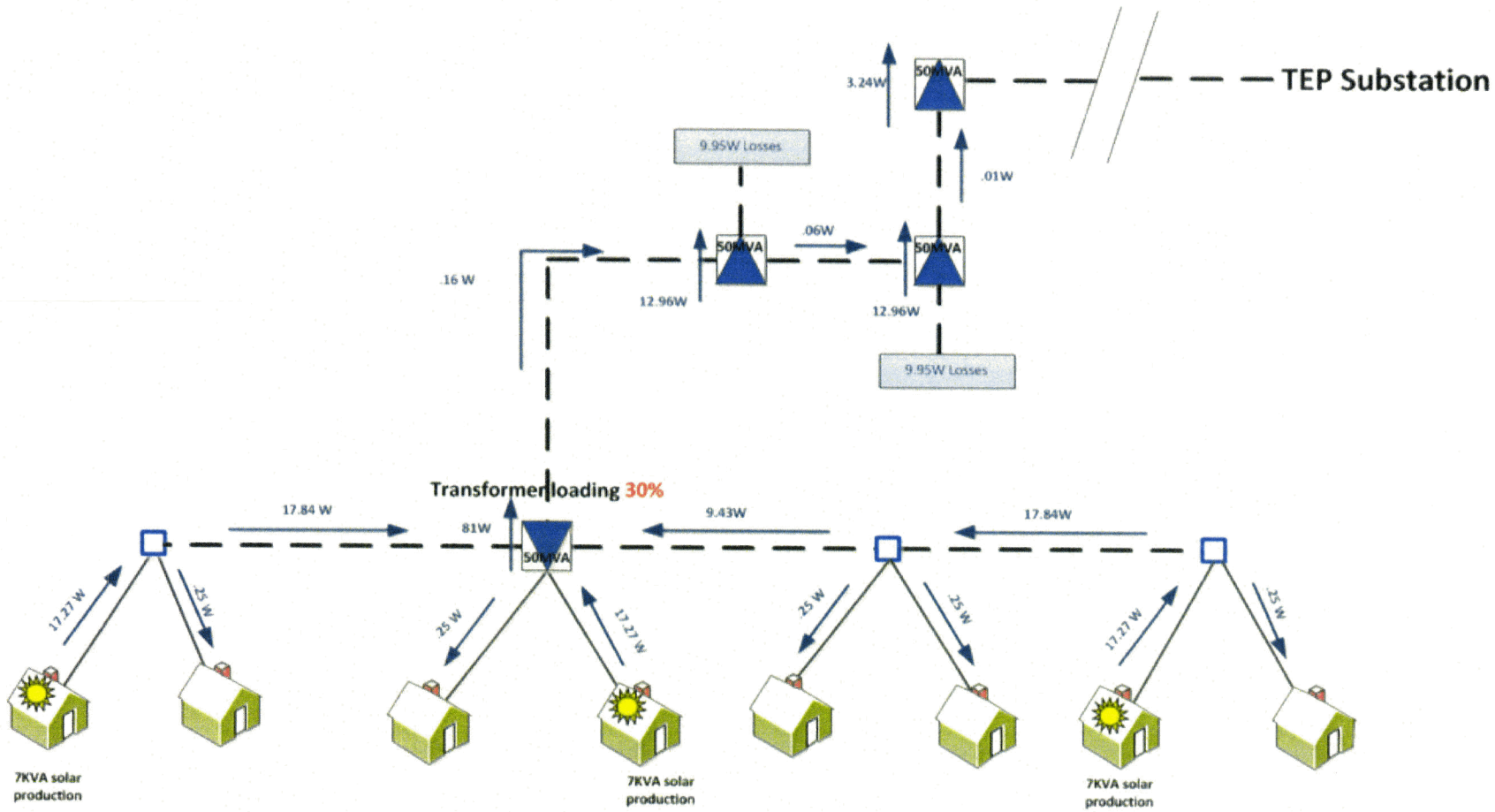

Typical loading in March at 12PM with 3 solar customers
TEP Substation
50kVA
3kVA
6kVA
9kVA
15kVA
6kVA
15kVA
Transformer loading 30%
4kVA
5.50kVA
5.50kVA
6.25kVA
.75kVA
.75kVA
6.25kVA
.75kVA
.75kVA
6.25kVA
.75kVA
7KVA solar production
7KVA solar production
7KVA solar production

Exhibit 6

Solar Generation losses associated with 3 houses producing 7kVA at daytime minimum



Total Solar Generation Losses = 228.45W

Exhibit 7

Solar PV Systems Per Transformer	Transformer Loading %	Losses (W)
1	2	44.2
2	16	107.95
3	30	228.45

Table 1

Exhibit HEO - 4

Fall and Spring Net DG Customer Load Shapes

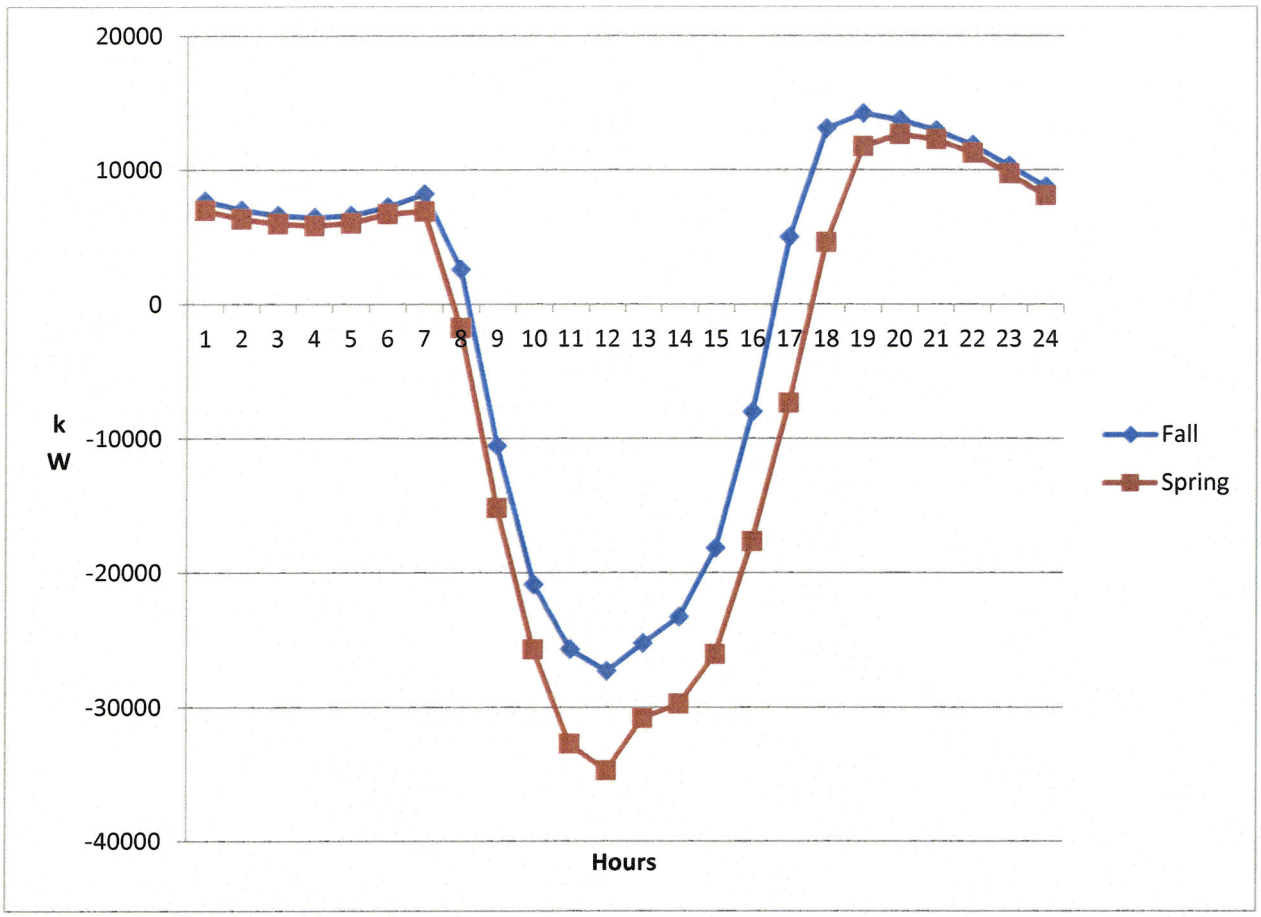


Exhibit HEO - 5

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON I
TEST PE
2016 Ra

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,907,042	2,034,604	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,907,042	2,034,604	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,120,083	68,926	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,881,608	2,228,598	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	515,071,285	11,378,554	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,828,770	3,354,083	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,259,048	1,530,017	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,175,481	291,062	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,407,161	-362,454	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,741	171	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	964,909	21,316	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,850,070	239,691	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,238,289	204,085	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,677,920	2,069,460	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,919,833	2,781,723	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,386,239	141,080	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,078,673	156,377	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,201,034	-424,174	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,071,851,753	23,678,515	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON I
TEST PE
2016 Ra

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,206,427	103,921	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,329,627	105,984	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	86,465,310	1,447,786	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,804,410	4,004,873	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	109,574,631	2,116,176	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	202,095,652	4,327,879	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	174,300,686	3,453,765	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,846,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	957,399,184	20,710,351	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,971,605	3,958,862	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,971,605	3,958,862	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,303,129,584	50,382,332	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,303,129,584	50,382,332	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON I
TEST PE
2016 Ra

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-69,131,154	-1,512,285	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,146,950	-9,060,647	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,065,799	-34,590	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,754,011	-29,369	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-29,086,540	-487,029	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-64,121,380	-1,494,711	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,580,256	-844,856	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,638,969	-2,005,279	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,973,907	-1,637,504	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,869,096	-1,090,916	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-911,402,588	-19,866,619	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-911,402,588	-19,866,619	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,066,623	-132,711	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,932,100	285,686	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,439,484	972,140	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,553,012	94,465	1,978,941	1,259,751	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,908,604	-98,934	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,377,386	-173,760	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,515,863	-33,160	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,469,595	316,531	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-232,544,260	-5,087,044	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-180,018,544	-3,856,788	-64,769,687	-31,004,554	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,211,708,451	26,658,925	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON E
TEST PE
2016 Ra

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,049,076	111,540	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	121,068,180	2,478,666	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,003,763	243,087	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,442,642	31,870	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,315,306	51,148	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,292,171	161,093	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,135,606	47,178	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,840,568	40,660	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,498,732	342,386	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,647,947	58,496	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,449,749	76,209	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	173,743,738	3,642,333	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,907,572	86,323	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener.	548 & 549	1,498,181	771,664	17,047	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,324	118	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,129	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,956,832	65,320	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,402	7,343	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,974,923	176,176	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	181,718,661	3,818,509	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	49,418,631	827,472	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	49,418,631	827,472	21,986,984	11,268,859	8,833,333	3,059,365	70,310
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	461,036	9,765	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	375,161	6,282	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	140,701	2,356	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	497,780	9,613	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	164,321	3,519	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,512,552	162,529	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	554,345	11,993	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	675,931	14,317	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	740,951	12,407	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,375,955	26,573	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,695	1,878	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	96,450	1,911	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	382,822	8,282	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	271,442	5,872	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,502,260	332,876	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,639,552	4,978,856	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	900,575	18,438	518,272	286,690	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,786,974	451,911	2,244,363	319,893	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E:	901-919	21,874,552	18,049,354	458,646	2,271,183	320,409	40,858	8,241	725,862

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E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,207,683	378,631	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,740,272	148,310	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,600,173	-123,224	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,368,650	140,133	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,225,791	269,011	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,942,223	812,862	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,384,857	30,295	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,183,691	25,894	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,424	337	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,583,972	56,526	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	761,006	16,739	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-215,275	-4,735	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,922,845	64,289	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,462	1,352	22,273	10,743	7,946	2,601	733
Rents	931	687,396	394,438	8,676	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,924,477	86,320	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,450,672	955,708	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	308,139,578	6,393,210	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003

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II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,650,296	167,355	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,459,942	662,293	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,468,095	142,888	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	46,345	776	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	99,472	1,666	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,307,861	21,899	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,539,078	59,188	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,683,692	32,640	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,318,311	71,062	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,996,835	59,143	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	59,524	1,041	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,115,598	68,156	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,461,173	185,093	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,968,769	1,569,783	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,074,000	69,587	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,310,360	161,495	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	12,033,863	260,345	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,769,256	38,704	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	36,091	604	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,223,570	530,735	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,219,497	420,438	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,219,497	420,438	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,443,068	951,173	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	423,551,414	8,914,166	176,779,041	106,440,234	89,304,612	32,949,858	4,679,806

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	0	0	0	0	0	0	0	0
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	0	0	0	0	0	0	0	0
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	0	0	0	0	0	0	0	0
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	147.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		0	0	0	0	0	0	0	0
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		-842,650,381	-423,574,343	-8,914,754	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
Rate of Return		-40.04%	-34.96%	-33.44%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%

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SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	0	0	0	0	0	0	0	0
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		0	0	0	0	0	0	0	0
OPERATING EXPENSES									
Production	500-555	421,678,184	181,718,661	3,818,509	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	49,418,631	827,472	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,502,260	332,876	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,049,354	458,646	2,271,183	320,409	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,450,672	955,708	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	308,139,578	6,393,210	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,968,769	1,569,783	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,223,570	530,735	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		-809,263,532	-404,331,917	-8,493,728	-169,856,698	-103,086,629	-86,830,259	-32,286,886	-4,377,416
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,219,497	420,438	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,219,497	420,438	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		-842,619,131	-423,551,414	-8,914,166	-176,779,041	-106,440,234	-89,304,612	-32,949,858	-4,679,806
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		-842,650,381	-423,574,343	-8,914,754	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
RATE BASE		2,104,677,691	1,211,708,451	26,658,925	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		-40.04%	-34.96%	-33.44%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%
Unitized Rate of Return		1.00	0.87	0.84	1.01	1.26	1.43	1.89	0.70

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,211,708,451	26,658,925	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	308,139,578	6,393,210	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,968,769	1,569,783	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,223,570	530,735	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	404,354,846	8,494,316	169,863,826	103,086,629	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,909,654	1,472,086	24,226,569	11,662,947	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,219,497	420,438	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	490,483,998	10,386,841	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	490,483,998	10,386,841	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210

Exhibit HEO - 6

TUCSON ELECTRIC POWER COMPANY
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,199,072	2,742,574	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,199,072	2,742,574	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,092,329	96,680	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	99,984,267	3,125,940	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	510,489,728	15,960,112	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	150,478,254	4,704,599	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	68,642,989	2,146,076	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,058,285	408,258	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,261,219	-508,396	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,672	240	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	956,326	29,899	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,753,559	336,203	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,156,114	286,260	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	92,844,656	2,902,725	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	124,799,776	3,901,779	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,329,433	197,885	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,015,709	219,341	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,030,241	-594,967	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,062,317,635	33,212,633	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,120,011	190,337	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,241,496	194,115	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	85,261,402	2,651,694	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,172,115	4,637,167	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	108,487,990	3,202,816	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,754,266	5,669,265	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	172,708,746	5,045,704	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	951,368,469	26,741,066	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	179,583,906	5,346,560	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	179,583,906	5,346,560	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,285,469,083	68,042,833	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Enérgy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,285,469,083	68,042,833	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,601,054	-2,042,386	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-406,498,695	-12,708,903	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,037,036	-63,353	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,729,589	-53,792	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,681,551	-892,018	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,885,393	-1,730,698	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,153,076	-1,272,036	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,017,451	-2,626,796	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,205,750	-2,405,660	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,486,698	-1,473,315	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-904,330,818	-26,938,389	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-904,330,818	-26,938,389	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,020,104	-179,230	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,817,069	400,717	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,098,720	1,312,904	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,509,749	137,728	1,978,941	1,259,751	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,826,335	-181,203	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,232,895	-318,251	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,504,239	-44,784	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,358,642	427,485	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-230,761,100	-6,870,204	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,560,493	-5,314,839	-64,769,687	-31,004,554	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,202,577,772	35,789,604	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,004,164	156,452	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	119,807,088	3,739,757	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	10,905,885	340,965	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,429,810	44,702	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,294,711	71,743	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,227,307	225,957	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,116,610	66,174	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,824,196	57,032	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,360,870	480,247	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,624,394	82,050	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,419,063	106,895	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	172,014,097	5,371,974	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,872,814	121,081	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	764,800	23,911	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,277	165	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,119	35	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,930,531	91,621	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	329,445	10,300	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,903,986	247,113	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	179,918,084	5,619,086	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,730,546	1,515,557	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,730,546	1,515,557	21,986,984	11,268,859	8,833,333	3,059,365	70,310
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	457,808	12,994	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	369,937	11,505	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	138,742	4,315	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	492,843	14,550	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	163,230	4,610	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,465,258	209,822	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	550,855	15,483	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	671,197	19,050	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	730,634	22,723	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,362,310	40,219	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,113	2,460	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,569	2,792	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	380,412	10,692	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	269,734	7,581	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,400,761	434,374	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	244,049,391	7,569,018	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	891,194	27,818	518,272	286,690	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,777,593	461,291	2,244,363	319,893	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E	901-919	21,874,552	18,039,973	468,027	2,271,183	320,409	40,858	8,241	725,862

TUCSON ELECTRIC POWER COMPANY
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,077,757	508,558	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,689,380	199,203	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,557,889	-165,508	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,320,564	188,220	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,133,480	361,322	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,663,291	1,091,794	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,374,238	40,914	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,174,615	34,971	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,305	456	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,564,158	76,340	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	755,255	22,490	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-213,648	-6,362	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,900,754	86,380	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	60,997	1,816	22,273	10,743	7,946	2,601	733
Rents	931	687,396	391,457	11,657	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,894,815	115,982	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,122,264	1,284,116	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	305,211,628	9,321,160	133,931,144	85,257,659	73,536,686	28,365,210	3,200,003

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,591,633	226,018	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,179,189	943,046	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,410,561	200,422	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,700	1,421	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	98,087	3,051	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,289,651	40,109	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,529,733	68,532	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,667,189	49,144	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,296,286	93,087	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,969,090	86,887	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,737	1,828	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,091,707	92,046	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,396,293	249,974	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,386,403	2,152,149	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,053,139	90,448	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,245,335	226,520	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,958,107	336,101	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,755,689	52,270	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,588	1,107	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,047,858	706,446	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,072,121	567,814	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,072,121	567,814	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,119,980	1,274,260	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	419,718,011	12,747,569	176,779,041	106,440,234	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues		0	0	0	0	0	0	0	0
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Of Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	440-446	0	0	0	0	0	0	0	0
Scrap Sales Revenues	451	0	0	0	0	0	0	0	0
Other Electric Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues - Misc Transmissic	447.5, 456.1	0	0	0	0	0	0	0	0
Other Electric - Ancillary	456	0	0	0	0	0	0	0	0
Excess Fac Revenues	447.4, 449.1, 456,	0	0	0	0	0	0	0	0
Total Operating Revenues	450-456	-31,250	-22,929	-589	-7,128	-605	0	0	0
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		0	0	0	0	0	0	0	0
V. NET INCOME		-842,650,381	-419,740,940	-12,748,158	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
Rate of Return		-40.04%	-34.90%	-35.62%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%

TUCSON ELECTRIC POWER COMPANY
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TUCSON I
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	0	0	0	0	0	0	0	0
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		0	0	0	0	0	0	0	0
OPERATING EXPENSES									
Production	500-555	421,678,184	179,918,084	5,619,086	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,730,546	1,515,557	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,400,761	434,374	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,039,973	468,027	2,271,183	320,409	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,122,264	1,284,116	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	305,211,628	9,321,160	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,386,403	2,152,149	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,047,858	706,446	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		-809,263,532	-400,645,889	-12,179,755	-169,856,698	-103,086,629	-86,830,259	-32,286,886	-4,377,416
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,072,121	567,814	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,072,121	567,814	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		-842,619,131	-419,718,011	-12,747,569	-176,779,041	-106,440,234	-89,304,612	-32,949,858	-4,679,806
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		-842,650,381	-419,740,940	-12,748,158	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
RATE BASE		2,104,677,691	1,202,577,772	35,789,604	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		-40.04%	-34.90%	-35.62%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%
Unitized Rate of Return		1.00	0.87	0.89	1.01	1.26	1.43	1.89	0.70

TUCSON ELECTRIC POWER COMPANY
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TUCSON I
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,202,577,772	35,789,604	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	305,211,628	9,321,160	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,386,403	2,152,149	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,047,858	706,446	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	400,668,818	12,180,344	169,863,826	103,086,629	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,405,465	1,976,276	24,226,569	11,662,947	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,072,121	567,814	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	486,146,405	14,724,434	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	486,146,405	14,724,434	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210

Exhibit HEO - 7

TUCSON ELECTRIC POWER COMPANY
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Allocation Phase

TUCSON I
TEST PE
2016 R

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,500,491	2,441,155	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,500,491	2,441,155	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,121,060	67,949	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,913,207	2,197,000	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	515,232,618	11,217,222	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,876,326	3,306,527	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,280,741	1,508,323	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,179,608	286,936	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,412,300	-357,315	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,744	169	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	965,211	21,014	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,853,469	236,293	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,241,182	201,191	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,707,262	2,040,118	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,959,274	2,742,282	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,388,239	139,080	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,080,891	154,159	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,207,049	-418,160	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,072,187,482	23,342,786	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,073,523	236,825	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,194,085	241,526	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	84,613,750	3,299,346	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	170,831,968	4,977,315	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	107,903,424	3,787,383	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,032,657	6,390,874	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	171,852,350	5,902,100	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	948,124,199	29,985,336	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,174,621	4,755,846	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,174,621	4,755,846	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,292,986,793	60,525,123	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,292,986,793	60,525,123	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

TUCSON ELECTRIC POWER COMPANY
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TUCSON I
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,826,706	-1,816,733	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,275,418	-8,932,180	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,021,563	-78,827	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,716,451	-66,930	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,463,684	-1,109,885	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,758,442	-1,857,649	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-42,923,271	-1,501,841	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-92,683,101	-2,961,147	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-81,792,515	-2,818,895	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,649,477	-1,310,536	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-907,145,153	-24,124,054	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-907,145,153	-24,124,054	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,039,907	-159,428	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,936,151	281,635	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,243,776	1,167,848	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,550,191	97,286	1,978,941	1,259,751	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,782,077	-225,461	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,155,166	-395,981	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,509,187	-39,836	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,405,872	380,254	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-231,520,154	-6,111,150	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,870,500	-5,004,832	-64,769,687	-31,004,554	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,206,971,139	31,396,237	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,050,657	109,959	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	122,233,868	1,312,978	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,007,210	239,640	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,443,094	31,418	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,316,031	50,423	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,294,455	158,809	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,136,275	46,509	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,841,145	40,084	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,503,586	337,531	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,648,777	57,667	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,450,829	75,129	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	174,925,925	2,460,146	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,908,795	85,099	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener.	548 & 549	1,498,181	771,906	16,805	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,326	116	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,130	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,957,758	64,394	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,506	7,239	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,977,421	173,678	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	182,903,346	2,633,824	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,360,385	1,885,717	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,360,385	1,885,717	21,986,984	11,268,859	8,833,333	3,059,365	70,310
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	456,071	14,731	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	367,127	14,315	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	137,688	5,369	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	490,188	17,205	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	162,644	5,196	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,439,817	235,264	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	548,977	17,360	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	668,651	21,597	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	725,084	28,273	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,354,969	47,559	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	86,800	2,773	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,095	3,266	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	379,116	11,989	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	268,814	8,501	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,346,159	488,976	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,609,891	5,008,518	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	909,246	9,767	518,272	286,690	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,795,645	443,240	2,244,363	319,893	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS. & SALES E:	901-919	21,874,552	18,058,025	449,975	2,271,183	320,409	40,858	8,241	725,862

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,140,984	445,330	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,714,146	174,436	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,578,466	-144,931	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,343,965	164,819	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,178,402	316,400	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,799,030	956,055	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,378,758	36,393	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,178,478	31,107	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,356	405	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,572,593	67,906	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	758,030	19,715	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-214,433	-5,577	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,911,415	75,719	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,221	1,592	22,273	10,743	7,946	2,601	733
Rents	931	687,396	392,896	10,218	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,909,130	101,667	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,280,753	1,125,628	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	307,948,668	6,584,120	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,616,605	201,046	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,464,212	658,022	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,470,121	140,862	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,352	1,768	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	97,342	3,796	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,279,855	49,905	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,524,706	73,559	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,658,310	58,023	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,284,437	104,935	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,954,165	101,812	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,430	2,136	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,101,877	81,876	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,423,911	222,356	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,741,871	1,796,681	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,068,612	74,976	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,312,650	159,205	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,917,353	376,854	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,761,464	46,495	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,318	1,377	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,095,398	658,907	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,134,856	505,079	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,134,856	505,079	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,230,254	1,163,986	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	422,920,792	9,544,788	176,779,041	106,440,234	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Solar Class COSS
Allocation Phase

TUCSON I
TEST PE
2016 R

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	0	0	0	0	0	0	0	0
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	0	0	0	0	0	0	0	0
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	0	0	0	0	0	0	0	0
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	447.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		0	0	0	0	0	0	0	0
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		-842,650,381	-422,943,721	-9,545,376	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
Rate of Return		-40.04%	-35.04%	-30.40%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Solar Class COSS
Allocation Phase

TUCSON I
TEST PE
2016 R

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	0	0	0	0	0	0	0	0
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		0	0	0	0	0	0	0	0
OPERATING EXPENSES									
Production	500-555	421,678,184	182,903,346	2,633,824	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,360,385	1,885,717	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,346,159	488,976	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,058,025	449,975	2,271,183	320,409	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,280,753	1,125,628	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	307,948,668	6,584,120	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,741,871	1,796,681	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,095,398	658,907	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		-809,263,532	-403,785,936	-9,039,708	-169,856,698	-103,086,629	-86,830,259	-32,286,886	-4,377,416
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,134,856	505,079	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,134,856	505,079	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		-842,619,131	-422,920,792	-9,544,788	-176,779,041	-106,440,234	-89,304,612	-32,949,858	-4,679,806
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		-842,650,381	-422,943,721	-9,545,376	-176,786,168	-106,440,234	-89,305,217	-32,949,858	-4,679,806
RATE BASE		2,104,677,691	1,206,971,139	31,396,237	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		-40.04%	-35.04%	-30.40%	-40.29%	-50.40%	-57.23%	-75.63%	-27.92%
Unitized Rate of Return		1.00	0.88	0.76	1.01	1.26	1.43	1.89	0.70

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Solar Class COSS
Allocation Phase

TUCSON E
TEST PE
2016 R

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,206,971,139	31,396,237	438,733,978	211,211,546	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	307,948,668	6,584,120	133,931,144	85,257,659	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,741,871	1,796,681	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,095,398	658,907	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	403,808,865	9,040,297	169,863,826	103,086,629	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,648,063	1,733,677	24,226,569	11,662,947	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,134,856	505,079	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	489,591,785	11,279,053	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	489,591,785	11,279,053	201,012,738	118,103,181	97,921,603	35,355,574	5,605,210

Exhibit HEO - 8

Load Data Summary - Table 1

Line No.	Load Information	kWh Annual	Notes
1	Residential Load	3,677,255,630	TEP Residential Load Profile (inc. solar)
2	Full Load for Solar Customers	113,287,652	Line 3 + Line 4 - Line 5
3	Solar Production	85,919,910	Calculated (Rio Rico profile)
4	Delivered to Solar Customers	73,269,926	Metered
5	Excess	45,902,184	Metered
6	Load Net Solar	3,603,985,704	Line 1 - Line 4
7	Counterfactual Load	3,717,273,356	Line 6 + Line 2
8	Netted (Solar Power Consumed @ Premise)	40,017,726	Line 3 - Line 5

Average Cost Data - Table 2

Line No.	Load Information	$	kWh	Avg. Cost ($/mWh)	Notes
1	Residential Full Production	$ 152,780,781	3,603,985,704	$ 42.39	Average embedded production costs for Residential sales net of solar customers
2	Avoided Fuel Cost	$ 1,116,525	40,017,726	$ 27.90	Average avoided cost of fuel related to solar energy consumed at premise
3	Residential Marginal	$ 98,397,088	3,603,985,704	$ 27.30	Average marginal cost for Residential energy sales net of solar
4	Marginal for Delivered Energy	$ 1,975,727	73,269,926	$ 26.97	Average marginal cost for energy delivered to solar customers
5	Marginal for Excess Energy	$ 1,129,968	45,902,184	$ 24.62	Average marginal cost for solar energy delivered to system

Subsidy Calculation - Table 3

Subsidy Description	Annual ($)	Per Customer ($)	Notes
Arbitrage Subsidy	$ 107,787	$ 11.18	(Marginal Cost of Delivered - Marginal Cost Excess) * Excess Energy
Production Cost Subsidy	$ 708,139	$ 73.42	(Embedded Cost of Production - Marginal Cost Delivered) * Excess Energy
Subsidy Production vs Marginal Cost of Excess	$ 815,926	$ 84.60	Sum of above
Power Consumed "Netted" Subsidy	$ 579,913	$ 60.13	(Embedded Cost of Production - Avoided Fuel) * Energy Consumed at Premise
Total Subsidy	$ 1,395,839	$ 144.72	
Customer Count		9,645	

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	)))))	DOCKET NO. E-00000J-14-0023

EXHIBIT
TEP-4
ADMITTED

Rebuttal Testimony of

H. Edwin Overcast

on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

April 7, 2016

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS CASE?

A. Yes. I provided direct testimony in this case on behalf of Tucson Electric Power (TEP) and UNS Electric (UNSE) or the Companies collectively.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses a variety of issues raised by other participants' direct testimony in this case. Specifically, I will discuss the numerous problems with the calculation of avoided costs for solar DG and provide an alternative framework for valuing any type of DG that reflects the market value of the particular source of DG. Avoided cost calculations should be consistent with the way other resources are valued in the context of the market. I will also discuss rate design for DG customers, errors made in analysis by solar DG advocates and certain policy issues.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized by sections beginning with this introduction and followed by the following sections:

Section II- Calculating the Value of Solar Based on Avoided Costs;

Section III- Rates for Solar DG Customers;

Section IV- Using Standard Cost Effectiveness Tests to Value Solar DG

Section V- Buy All Sell All Approach Is a Better Option for Matching Solar DG Output and Avoided Costs

Section VI- Services Provided to Solar DG Customers

Section VII- Miscellaneous Issues

Section VIII- Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I reach a number of conclusions throughout my rebuttal testimony. The most important of those conclusions include:

1. Solar DG is only entitled to short-run avoided energy costs as a measure of energy value.
2. To the extent there are provable avoided capacity costs, those costs should be fixed at the time the solar DG is valued initially.
3. Solar DG customers should be a separate class of service in the cost of service study.
4. Solar DG customers should be billed on three part rates – customer, demand and energy with energy be seasonal TOU based that recover the class revenue requirement.
5. The use of standard practice tests- Participant, Ratepayer Impact, Total Resource Cost and Societal Cost Tests- are screening tools and should not be used to value solar DG.

6. A Buy-All/Sell-All Approach produces the best compliance with cost causation and matching principles of rates.
7. Avoided costs must be based on the actual private costs the utility avoids.

II. CALCULATING THE VALUE OF SOLAR BASED ON AVOIDED COSTS

Q. WHAT IS THE BASIS FOR DETERMINING AVOIDED COSTS FOR SOLAR DG?

A. Section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 paragraphs (b) and (d) taken together establish the basis for rules promulgated by the FERC related to the purchase of energy from qualifying facilities including solar DG (CFR Title 18 Chapter I Subchapter K Part 292 ("FERC Rules")) and establish a specific ceiling at a level not to exceed incremental costs of the utility (paragraph (b)) which is further defined in paragraph (d). These same FERC Rules also regulates the rules for rates charged by the utility to these customers. The concept of net metering was added to the PURPA standards for utilities by a subsequent amendment that did not alter the purpose of these standards or the provisions related to avoided costs. This is the basis for determination of avoided costs and all subsequent analysis of avoided costs and changes based on market values are included in the amended regulations. In its rules as set forth in the current amended version and currently effective, the FERC establishes certain requirements for utility purchases. TASC witness Beach refers to the PURPA provisions selectively related only to the obligations related to generation.[1]

[1] TASC Direct at p.13 and 17

It is instructive to note that the utility purchases are for two separate components capacity and energy. These two products are treated differently under PURPA as they should be in this proceeding. The FERC Rules also define avoided costs as "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[2] Two points are noteworthy namely that capacity and energy are separate products and that avoided costs may be based on purchases from another source as the basis for determining avoided costs. In areas with organized capacity markets such as PJM, NYISO and ISONE the FERC has eliminated the requirement of avoided cost and allowed that to be replaced by a market value. This is consistent with utility proposals to value solar DG capacity based on competitive market transactions for utility scale solar DG. Treating capacity and energy separately is particularly appropriate for the "as available" nature of the energy provided to the utility by solar DG.

This latter observation is important since the avoided costs of energy for TEP and UNSE may be determined by either the lower of cost or market hour by hour. Hence the suggestion by some solar DG advocates that it is permissible to use the "energy cost of the proxy marginal resource"[3] to value avoided energy costs cannot possibly be correct ever. No marginal unit of capacity can be at the margin in all hours of the year nor can even one fuel be at the margin in all hours in an integrated regional market. In addition, the suggestion that solar DG should receive the net present value (NPV) of the

[2] CFR Title 18 Chapter I Subchapter K Part 292, Subpart A, §292.101 Definitions (C), (ii), (6)
[3] See Table 2 of the direct testimony of TASC witness Beach page 20.

energy cost savings as suggested by the solar DG witnesses is inconsistent with the FERC Rules and with the economically proper calculation of avoided costs. As I demonstrate later in my testimony the methods used in IRP proceedings for valuing assets and programs form the basis for planning decisions but not for ratemaking. IRP values are simply tools to choose between alternatives. They do not value assets for cost of service or revenue requirements. No utility is allowed to charge the NPV of energy cost savings as the basis for fuel cost recovery nor is there any regulatory model that uses the levelized carrying charge for capacity as the basis for capacity related revenue requirements. The planning tools allow for an assessment of the relative relationships necessary to choose between alternatives but are not the statutory basis for cost recovery.

Those FERC Rules require that "as available purchases"[4] be compensated for energy at the time of purchase. Solar DG is a perfect example of an "as available" resource since the amount delivered to the utility is completely at the discretion of the solar DG customer and the loads placed on DG at the customer premise. Further, solar DG cannot meet the requirements spelled out for different treatment related to a legally enforceable obligation. Among other requirements, the FERC Rules spell is a contract that provides the duration of the contract, the committed capacity and energy pursuant to a schedule, a termination notice requirement and sanctions for non-performance. Solar facilities at end use premises have the first claim on the output and energy is only delivered to the system as it is unused by the premise. Thus under the provisions of the PURPA FERC Rules, there is no option for solar DG customers to have avoided energy

[4] CFR Title 18 Chapter I Subchapter K §292.304 Rates for purchases, (d)

costs based on a levelized long-run avoided energy cost study. Further, since there is no contract between the solar DG customer and the utility that satisfies the requirements under PURPA there is no basis even for long-run avoided capacity costs and in particular no capacity value at the time of system peak since the available kW at the peak for delivery to the utility is zero as a result of load exceeding the DG output. I note that the solar DG advocates all argue that only the delivery energy and capacity should be used to determine the value of solar.

Q. DO YOU AGREE THAT THE VALUE OF SOLAR SHOULD BE BASED SOLELY ON THE ENERGY DELIVERED TO THE UTILITY AS RECOMMENDED BY THE SOLAR WITNESSES?

A. No. Solar DG has a different value when it is based on the total contribution of DG as energy delivered and energy saved. In particular, there are different avoided costs based on the total contribution of solar DG and those should be recognized through the same process that is used for evaluating conservation investments, community solar DG and utility scale solar DG. There is also a different value based on the cost of service analysis used for solar DG customers. "As available" energy has no capacity value simply because no energy is delivered to the system in the peak hour. Looking at the total DG output creates an opportunity for avoided capacity costs based on various measures of peak capacity as I will discuss below. In that case it is possible to determine the avoided capacity value if any based on the long-run avoided capacity costs. There is no reason to use long-run avoided energy costs and pay credits on that basis however.

The reason is straight forward; no power source is allowed to collect the avoided energy costs on a levelized basis over its operating life because that is not consistent with the matching principle of rates. Marginal energy costs are simply a short-run concept and both DG and energy efficiency (EE) investments only save the actual energy costs based on a short-run period. Since these costs are variable in both the short-run and the long run the economically correct price signal is short run marginal costs. If compensation is based on a levelized cost of energy the only thing we know for certain is that that number will be wrong even in the near term for many reasons as I will discuss below. When the energy value is levelized the economics of solar DG investments will produce excess returns over the market value when the levelized value is too high and will produce below market returns when the value is too low. Thus, in a rising fuel cost environment the solar DG customer will see declining benefits relative to the investment and in a declining fuel cost environment will receive windfall profits. I should note that this is not speculation since one needs only to look to the PURPA contracts of the nineteen eighties where actual energy prices were below the levelized costs of energy in the contracts and there was billions of dollars in stranded costs in markets such as New York associated with the buyout of PURPA contracts. Further, IPP contracts for gas fired generation did not value energy at the levelized long-run costs but rather based the energy prices under the contract on a market based index of variable costs. Thus energy costs escalated with the market and the same should be true of the value of solar energy.

Q. FOCUSING ON THE ENERGY COMPONENT SEPARATE FROM THE CAPACITY COMPONENT, WHY IS IT LIKELY THAT A LEVELIZED ENERGY, AVOIDED COST WILL BE WRONG IN BOTH THE NEAR TERM AND THE LONG-TERM?

A. Avoided energy costs are determined in each period by a number of factors that introduce volatility into those costs. Obviously we know that fuel prices are volatile over time and to assure reasonable recovery of those costs by a utility costs are adjusted by a formula rate such as the PPFAC for TEP and UNSE. In the short run, energy costs change with load, fuel prices, forced outage rates, scheduled maintenance and other variables related to near term system dispatch requirements such as unit deratings and ramp rates. In the long-run these costs change based on technology, long-term load and capacity demand growth, significant changes in load shape such as those related to intermittent resources, plus all of the same short-run impacts. As a result, the NPV of energy avoided costs will be higher than actual costs in the near term and below actual costs in the long term unless fuel prices actually fall as a result of technology or other market factors.

Q. WHO IS THE PRIMARY BENEFICIARY OF THE CALCULATION OF ENERGY NPV?

A. The solar installer is the primary beneficiary of calculating an NPV for energy. It allows the solar energy provider to compete against a higher payment for solar DG. This enhances the margin calculation for solar DG installations. Ultimately, the customer has reduced benefits as avoided costs increase above the NPV based payment.

As a result, the customer who expects to save more as energy prices rise actually saves less when energy prices rise above the NPV energy value as they must over time.

Q. HAS THE FERC ADOPTED MARKET BASED ENERGY CHARGES FOR QF'S?

A. Yes. For the competitive markets where hourly prices are based on marginal costs (LMPs), the FERC has determined that QF customers no longer have access to the levelized energy cost component of avoided costs. This is actually the most economically correct way to reflect avoided energy costs in payments to any competitive resource for energy production, since levelized long run energy costs are not consistent with least cost planning or even how energy costs are determined for utility assets. Energy is a short-run concept, while only capacity is a long run concept in valuing utility generation or non-utility generation. In particular, the short-run valuation is consistent with cost causation that is fundamental to the concept of economic costs. Causality asks the simple question of how will cost change with a change in output. There are different answers to this question depending on the change. In any event energy costs change with changes in energy consumption based on the underlying real time mix of fixed resources. An additional kWh of load does not impact costs even in the next week, much less twenty years in the future. For an incremental kW of consumption, there may be only a short-run impact on costs if there is available capacity to serve the load. If the kW increase is a permanent increment of capacity at the time of the planning peak (the planning peak being different for production, transmission and distribution), then that kW may contribute to the need for additional

capacity in the future when added with other kW increments. Therefore it is only capacity related avoided costs that have a long-run dimension. Further, that dimension cannot be expressed as a value that should be reflected based on the current increment of capacity alone as that is likely to be zero. Rather, it is expressed as the actual lumpy capacity increment that is avoided or delayed at some point in the future as noted in the FERC Rules. For the current value of an avoided capacity unit, the cost of that capacity per kW installed or the cost per kW of a capacity contract from the market would be discounted to the current period using the utility marginal cost of capital since that would be the cost avoided.

Q. IS THERE CONFUSION ABOUT THE APPROPRIATE DISCOUNT RATE FOR CALCULATING THE NPV OF AVOIDED COSTS?

A. Yes. Determining the correct discount rate is more complicated than it seems because the basic confusion related to determining the discount rate for application in different uses and for different streams of costs or revenues. This distinction is relatively straight forward when we consider the comparison of real and nominal dollars. If the analysis uses real dollars of revenue and costs there is no inflation built into the calculation and the discount rate should be a real discount rate. If inflation is included in costs and revenues the nominal discount rate applies because the nominal rate includes the effect of inflation on the opportunity cost of capital. Properly calculated the real and nominal process should produce the same NPV. Similarly, discount rates may differ based on whether the costs are private costs or social costs.

In the case of utility avoided costs, the costs are private costs and the appropriate discount rate is the utility's long-run marginal cost of capital. This represents the opportunity cost of securing the necessary funds for constructing new plant or the lost opportunity costs from acquiring a capacity in the market. In either case the correct discount rate depends on the risk of the investment that the capital is being used to fund. It is forward looking and bears no relationship to the weighted average cost of capital used to determine revenue requirements. It is also not the societal discount rate as recommended by witness Kobor.[5] It is also not the weighted average cost of capital used by witness Beach in his analysis.[6]

Q. IS THERE ANY CONSENSUS AS TO THE SOCIAL DISCOUNT RATE?

A. No. There is no consistency between the level of social discount rates used by government agencies or those calculated by economists. The values recommended for social discount rates in just a few Federal agencies range from 10% real (OMB) and the CBO uses 2% real discount rate.[7] From a theoretical basis, the concept of a social discount rate should reflect the opportunity cost of capital or the opportunity cost of private consumption as the social discount rate, since the government competes with dollars used to finance private capital or private consumption or both. It is also important to note that these discount rates are real discount rates and cannot be used for discounting nominal dollars.

[5] Direct Testimony of Briana Kobor, p. 23, l. 18-19
[6] Direct Testimony of B. Thomas Beach, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)", p.7
[7] A Student's Guide to Cost Benefit Analysis for Natural Resources: Lesson 6 The Social Discount Rate, http://ag.arizona.edu/classes/rnr485/ch6.htm, p.4

Q. SHOULD AVOIDED COSTS OF DISTRIBUTION PLANT BE INCLUDED IN THE CALCULATION OF SOLAR DG VALUE?

A. Yes to the extent that there are actual avoided costs. In the case of solar deliveries only, it is impossible for DG to avoid any costs because the maximum use of the delivery system occurs at a time when there is no solar diversity and low loads. Further, if you value solar only based on excess generation as suggested by the solar advocates, there is no avoided costs in any event. The proper valuation should be based on the total output of the facility, not just the value of exports. In that case, it is possible that there may be some avoided capacity costs on the distribution system given local conditions. There are no generalized avoided distribution capacity costs as suggested by the solar DG witnesses. To understand the basis for this conclusion one needs only to understand three issues:

1. The planning, design and operation of the distribution system is based on installed capacity for a premise;
2. The fact that marginal cost for an increment of capacity is not the same as for a decrement of capacity; and
3. The investment and capacity of the system are not continuously variable but are lumpy.

These three facts taken individually have implications for the possibility that solar DG avoids distribution capacity costs in general.

Since the local facilities are designed based on connected load, the addition of DG would not require a change in the capacity of local facilities except in the event that all

of the customers connected to a given transformer installed solar DG. In that event the export function would require **more** local capacity not less; in fact my direct testimony (pages 16-17 and the class NCP value in the base cost study and the solar class study for solar DG customers) shows that for TEP the solar class NCP for exports is greater than for imports. The reduction in local demand at the NCP peak would only result in a smaller transformer replacing a larger transformer at the end of the transformers useful life under the condition that solar DG for the customers on the transformer could reduce the NCP loading by about 2 kW per customer served on the typical residential transformer since transformer sizing as noted above is not continuous.

In any event, to reach this level of NCP peak load reduction would require too much capacity for export to be served by the next smallest transformer size. There is no way to free-up enough local capacity to avoid distribution costs locally.

The fact that marginal costs for increments and decrements of capacity are not equal is also an issue with respect to avoided capacity costs for distribution facilities. Given the sunk cost nature of capacity investments and the lumpiness of capacity for distribution equipment, there is no likelihood that adding solar DG would avoid any distribution costs and conversely, a decrement of load would not eliminate any cost in the short run. However, the marginal cost of adding capacity to the delivery system is likely to be positive as it relates to changes resulting from customer additions (extending the system to attach new customers adds at least the minimum system components that includes capacity for delivery) and from capacity additions when the minimum system is inadequate to serve the load. Thus when calculating marginal cost of growth in

capacity on the distribution system the result is a number substantially greater than the avoided distribution costs associated with a load decrement.

Q. DO SOLAR ADVOCATES RECOGNIZE THE DIFFERENCE BETWEEN AN INCREMENT OF CAPACITY AND A DECREMENT OF CAPACITY?

A. No. Both VS witness Volkmann and TASC witness Beach recommend the use of a marginal cost analysis as the basis for assigning avoided distribution and transmission cost to solar DG. Witness Volkmann recognizes that DG and other DER resources may cause an increase in distribution costs.[8] However, he calls for a marginal cost study to determine avoided costs. TASC witness Beach uses a regression analysis of historic costs as the basis for determining marginal T&D costs which he equates to avoided T&D capacity costs. Neither approach is correct because it relies on the incorrect assumption that the marginal costs associated with a load increment are equivalent to the avoided cost of a potential load decrement. I use the term potential load because as I have shown in my direct testimony the maximum demand on the delivery system does not occur because of load but because of reverse power flows for delivery to the system. In that event witness Volkmann is correct that under the concept of cost causation solar DG customers cause more costs rather than avoiding any costs.

[8] For example the use of storage heating in Europe has caused a significant shift in the distribution system peak as storage units begin the heating cycle at the end of the on-peak period. During cold weather, there is no natural diversity and the need to store adequate heat for the next on-peak period results in higher charging kW then the required heating kW absent storage. The same phenomenon would occur for storage cooling and storage water heating. The diversified off-peak demand for storage water heating is over three times the winter coincident peak demand and more than that for the summer NCP demand.

Q. WHY IS THE USE OF REGRESSION ANALYSIS BY WITNESS BEACH INCORRECT?

A. The methodology of regression analysis cannot produce reasonable results for a number of reasons. First, the implicit assumption in his analysis is that all new dollars invested in a distribution or transmission plant account are growth related. That is an incorrect assumption. Many of these dollars are related to serving existing load where existing infrastructure must be replaced to maintain the same level of service. New dollars will be greater than the depreciated value of the assets removed. So the growth of rate base is not related to load growth alone. The same logic also tells us that not all of the increases in O&M expenses for T&D are related to growth. In fact, most are not growth related at all. Second, the assumption that growth in T&D investment is related to system peak growth is also incorrect. It is not coincident peak that causes all T&D investment. That would only be true if all of the T&D assets reached their maximum capacity at the same hour as the coincident peak load — a proposition we know is false. Using the system peak to calculate the growth in T&D capacity results in a higher avoided cost per kW and inflates avoided costs for capacity. Third, using sunk costs to estimate marginal costs is inconsistent with the concept of marginal costs, which is inherently forward looking not backward looking as the historic regression analysis used by witness Beach. Witness Beach fails to recognize that those sunk costs from FERC Form 1 that are part of revenue requirements may bear no relationship to the actual marginal cost going forward because of changes in technology, changes in the relative cost of inputs and economies of scale. Fourth, the regression analysis cannot address the issue that plant additions are not designed to simply meet the current load

requirements but to be able to meet load over the useful life of the asset. New assets are lumpy additions. For that reason alone the use of measured growth rather than capacity growth overstates marginal costs. A simple example will illustrate this concept. When a residential subdivision is wired for electric service, transformers are installed based on the underlying buildout of homes. Not all homes are added in the same year so there is a mismatch between load and capacity that is resolved over time but not in one year.

Q. WHAT IS THE RELEVANCE OF LUMPY ADDITIONS TO THE CALCULATION OF AVOIDED COSTS?

A. Although the solar advocates recognize the issue of lumpy additions they do not properly address the implications for the calculation of avoided costs. Instead, witness Volkmann opines that "The methodology should also credit DG solar and other DERs for incremental contributions to distribution capacity relief, even if the utility has not identified an imminent capacity expansion project on the interconnected feeder or at the associated substation."[9] Simply put, in the absence of a need for marginal capacity, there is no value to any incremental contribution to capacity relief and any attempt to place such a value is misplaced and results in an over-estimate of the value of solar that greatly exceeds any reasonable level of avoided costs if any. There is no basis for assuming or concluding that solar DG ever saves any dollars of distribution costs except on specific circuits with unanticipated high load growth where there is sufficient aggregate solar DG to allow for capacity deferral without creating a new peak period for the circuit resulting from excess delivery causing the circuit peak. In part, this is because the absence of any need to add capacity on a circuit, feeder or substation means

[9] Volkmann Direct p. 21

that the solar DG customer does not save the utility any costs (and may increase the costs) so that any compensation for a cost not actually avoided is a direct subsidy in the current period and continues to be a subsidy potentially over the whole life of the DG facility given the average life of distribution assets. Recognizing the lumpy nature of utility assets must necessarily alter both the calculation of avoided costs and the localized nature of distribution investments.

To calculate the avoided costs for distribution the first necessary condition is that there is a capacity constraint on the particular local distribution facilities where the solar DG is to be connected. Second, the solar DG must be able to result in one of three outcomes:

1. Avoid the capacity addition in total;
2. Delay the capacity addition for some period; or
3. Reduce the current level of investment in those local facilities.

If solar DG eliminates the need for capacity the avoided cost per kW is the levelized annual carrying charge rate applicable to the avoided capital costs of the facility avoided. If the solar DG delays the capacity upgrade, the avoided costs is the NPV of the differences in the levelized payments for the current installation and the levelized payments for the future installation. Finally, if the solar DG permits a smaller investment the value of the DG is the NPV of the differences in the levelized costs of the two different projects. The value of solar DG is far less than the marginal cost of distribution capacity in general except for the case where solar DG eliminates the need for the capacity upgrade in total by freeing up capacity in a sufficient quantity to

address the capacity requirements over the remaining life of the existing assets. It is far more likely given the lumpy nature of investments that the avoided cost would be based on either a deferral value or a replacement value.

Table 1 below provides perspective on the avoided costs associated with the more likely option to down size a transformer.

Table 1

Avoided Transformer Costs

kVa	Under Ground	Levelized Carrying Charge Rate 11.55% Annual carrying costs	Difference	Difference per kW	1752 kWh per kW Cents per kWh @20% Capacity Factor
25	$3,800	$439	$46	$1.85	$0.0011
50	$4,200	$485	$35	$0.69	$0.0004
75	$4,500	$520	$0		
100	$4,500	$520			
150					
167	$5,000	$578	$58	$0.35	$0.0002
225					
250	$6,500	$751	$173	$0.69	$0.0004

As the table illustrates the value of a smaller size transformer, assuming that solar DG would permit that downsizing of a transformer is measured in a fraction of a cent per kWh produced by solar DG. Similarly, a delay of say five years would also result in a fraction of a cent per kWh produced by solar DG. These values are nowhere near the values calculated by TASC which range from $0.015-$0.032 per kWh for residential customers. There is virtually no reason to assume that other distribution facilities such

as conductor and poles would be changed out as a result of solar DG. The multiple errors in the TASC analysis make these estimates incorrect and inconsistent with properly calculated avoided costs. Simply put, there is no rationale for a system wide avoided distribution cost calculation, which implicitly assumes that every circuit has no capacity to accommodate load growth. Further, if one assumes that there is no capacity on any conductor we would see the need to reconductor the system on a continuous basis when customers were added to a circuit or a feeder.

Q. HOW SHOULD THE FORECAST OF AVOIDED CAPACITY REQUIREMENTS BE DETERMINED?

A. The forecast should include not only load growth but also the projected growth in solar DG penetration as well other DG options, DER and DSM over the period for which avoided capacity costs are calculated. Essentially avoided costs are based on the full utility planning models. This process is not the one recommended by witness Kobor who states "The valuation of DG exports will be most relevant if it examines current and/or near-term expected penetration levels on the utility's system."[10] Such a recommendation is not surprising since it results in over valuing both the capacity and energy benefits of solar DG. However, it is not part of the utility plan to ignore trends that impact capacity requirements either positively or negatively.

[10] Kobor Direct at p. 24

Q. FROM AN AVOIDED COST PERSPECTIVE HOW DOES THE FACT THAT SOLAR DG IS NON-FIRM, NO TERM COMMITMENT AND NON-DISPATCHABLE IMPACT AVOIDED COSTS TO VALUE SOLAR DG?

A. Each of these three characteristics reduces both the capacity and the energy value as compared to the utility avoided cost unit such as a combustion turbine or even a utility scale solar DG unit. These factors are specifically itemized in PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION issued by the FERC Rules current as of March 16, 2016. §292.304 provide detailed requirements for a utility to purchase energy and capacity from QF facilities including solar DG.

Non-Firm Sales

Non-firm sales are functionally "as available sales" as defined by the FERC Rule. This means that the owner of the QF decides when energy will be delivered to the utility. In the case of solar DG the deliveries are first used to serve the customers own load and to export energy when net of load is less than the production from the facility. Simply, the utility can never be sure when energy will be delivered to its system since the customer always has the first call on the production capacity of its unit.

Moreover, that capacity varies with factors that neither the solar DG owner nor the utility control such as cloud cover or ambient temperature impacts that raise or lower available capacity relative to the kW nameplate capacity.

No Contract Term Commitment

The only basis for choosing a payment other than the avoided costs at the "time of delivery"[11] is for the customer to have a contract for energy or capacity that is "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term."[12] That legally enforceable obligation is defined in the regulations as "The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance."[13] That is certainly not applicable to Solar DG.

Performance Obligations

As I mentioned earlier, the ISO-New England recognizes the very different service characteristics of the capacity product from the energy product; and in fact, has recently modified its capacity market rules to introduce specific performance obligations on generators receiving capacity payments. This is an example of the quid pro quo that must be established for a true capacity resource. DG capacity by its nature cannot be associated with specific performance obligations and from a utility planning perspective cannot be viewed as a capacity resource particularly when the peak hour is shifting later in the evening.

Non-Dispatchability

The regulations also note that the ability of the utility to dispatch the QF facility is a determining factor for avoided costs.[14] This creates value from the utility to take

[11] §292.304 Rates (d) (1)
[12] §292.304 Rates (d) (2)
[13] §292.304 Rates (e) (2) (iii)
[14] §292.304 Rates (e) (2) (i)

advantage of low or negative prices in the market place rather than pay the fixed rate for solar DG energy delivered when lower cost alternatives are available for customers.

Q. DOES THE FERC RULE REQUIRE THAT A UTILITY CONSIDER THE AGGREGATE VALUE OF CAPACITY OR ENERGY?

A. Yes. The FERC Rules also require that the utility use the aggregate value of any capacity or energy in calculating the avoided costs.[15] That aggregate value is reflected in the avoided cost analysis used by utilities as it applies to avoided energy costs and capacity cost for generation. A different aggregate concept must be used for transmission and distribution since those costs are only avoided related to a particular transmission delivery node and for individual substations, feeders and circuits. The logic for this conclusion is that solar DG located in one delivery node portion of the transmission system cannot save costs for capacity for any other delivery node. The same is true for calculating avoided distribution costs by the systems basic components-substations, feeders, circuits and transformers.

The regulations also require that the smaller capacity increments and shorter lead times also be considered. This point may have positive value for specific circuits and feeders if capacity is constrained but may have no value if the aggregate capacity is too small to impact the capacity requirements of local facilities. As noted above the fundamental problem of lumpy capacity additions causes the solar DG to be unlikely to reduce costs for distribution capacity because in order to reduce capacity requirements for local facilities the aggregate solar DG on the system must be large relative to the size of the facilities loads. If it reduces peak loads sufficiently at the time of class NCP to save

[15] FERC Rule §292.304 Rates for purchases, (e), (2), (vi)

distribution capacity it is likely that the load at the time of maximum output to the system will be too large to allow for smaller equipment.[16] The modularity of solar DG has no value as it relates distribution beyond specific circuit requirements that cannot be incorporated in the general value of solar DG but must be evaluated for each circuit or feeder on the system.

Q. IS VALUING SOLAR DG THE SAME AS DETERMINING THE AVOIDED COST PAYMENTS UTILTIES SHOULD PAY FOR EXCESS SOLAR EXCESS DG ENERGY?

A. No. Given the specific nature of solar DG as an intermittent resource, with excess delivery to the system on an as available basis, with no contractual commitment to deliver (and no penalties for failure to deliver) and non-dispatchable capacity there is no justification for any payment above the avoided cost at the time the power is delivered to the system for excess generation. Any capacity value based on actual, quantifiable avoided capacity costs should be treated separately from the compensation for energy; should be an annual payment; and should be performance based so that if the facility is out of service during peak periods or is not maintained over the life, capacity payments would be reduced.

Moreover, solar DG may be valued in the context of IRP just like any other generation source. That value may include all of the marginal Pareto-relevant externalities as part

[16] The math for this conclusion is straight forward. To replace a 50 kVa transformer with a 25 kVa transformer one needs to reduce load by 25 kVa or 5 kVa for five customers. At the class NCP this would mean that each customer would need at least 25 kVa of capacity because of the peak afternoon output of 20% of capacity. Even with only one 25 kVa solar DG facility the output in a low load period would exceed the transformer loading so there would be no way to reduce the size of the transformer.

of the value.[17] Avoided costs are defined in the FERC Rules as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[18] To the extent that externalities have not been internalized through law or regulation those costs are not avoidable. The FERC regulation also states that the regulation does not require a utility to pay more than avoided costs under the regulation.[19] This means that the inclusion of externalities not yet internalized such as carbon costs is not permitted under the FERC regulation as part of avoided costs. That same position is consistent with economic theory and coincides with the views of AIC witness O'Sheasy (who points out the inequity and inefficiency associated with including the externalities in the avoided costs), APS witness Brown (who points out the inefficiency and incorrect logic associated with the treatment of externalities not otherwise internalized), and Staff witness Solganick (who points to external costs already included in the actual avoided costs).

III. RATES FOR SOLAR DG CUSTOMERS

Q. HOW SHOULD RATES BE DETERMINED FOR SOLAR DG CUSTOMERS?

A. Rates should be designed to reflect cost causation. This requires that solar DG customers' rates are fully unbundled, three-part rates with seasonal and TOU features

[17] The definition of a Pareto-relevant externality is an externality where the extent of the activity may be modified in a way that the "externally effected party A, can be made better off without the acting party, B being made worse off." See "Externality" by James M. Buchanan and Wm. Craig Stubblebine in Economica, N. S. 29(1962) pp 371-384

[18] §292.101 (C) (6)

[19] §292.304 (a) (2)

for energy and demand. No other rate design option will adequately track cost causation and match costs to rates paid on a real time basis. As a policy matter, this is a critical component for equitable treatment of all customers. This policy is explained in detail in my Direct Testimony at pages 9-16 and I will not repeat that discussion here. In addition, I have provided a response to VS 1.11 that provides citations to both the Supreme Court decisions and the D.C. Circuit and 7th Circuit decisions that support these rate propositions.

I also find further support in the FERC Rules implementing PURPA requirements for QFs that state that the requirements for rates to sell power to QFs. Specifically the FERC regulations state that "Rates for sales which are based on accurate data and *consistent system wide costing principles* shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost related characteristics."[20] (Emphasis added.)

The FERC recognizes that partial requirements customers differ from full requirements customers and as a result require service not required by other customers. In particular these services include supplemental power and back-up power on a firm basis.[21] Both of these services are defined in the regulation and are the same services that utilities supply to solar DG customers when the utility delivers energy and capacity to those customers.

[20] §292.305 (a) (2)
[21] §292.305 (b) (i) and (ii)

1 **Q. DO SOLAR INTERVENERS OPPOSE THIS TREATMENT?**

2 A. Yes. The solar DG advocates support TOU energy rates and a minimum bill and
3 oppose fixed charges such as cost-based customer charges and demand charges.[22] While
4 TOU based energy charges provide an improvement in price signals for the energy
5 component of cost and the value of energy delivered based on seasonal and diurnal cost
6 variation, they do nothing to address cost causation related to demand. Continuation of
7 the rates advocated by solar DG interests will artificially enhance the development of
8 solar DG through shifting costs to non-participant customers as demonstrated by the
9 counterfactual cost of service study in my direct testimony that fully complies with the
10 FERC requirement that consistent system wide cost principles are applied. Application
11 of those same principles also demonstrate that the solar customers are properly included
12 in their own cost study as demonstrated by the separate solar class cost study filed in my
13 direct testimony.

14

15 **Q. HAVE SOLAR INTERVENORS PROVIDED ANY EVIDENCE TO SUPPORT**
16 **THEIR ARGUMENTS ABOUT COST CAUSATION AND RATE DESIGN?**

17 A. No. Aside from an assertion that "Cost studies adopted by the California PUC have
18 demonstrated that demand charge structures actually overcharge solar customers
19 relative to the costs that they impose on the system, and undervalue the peaking
20 capacity that solar DG provides,"[23] there has been no attempt to develop a fully
21 unbundled cost study that applies system wide cost causation factors. Further, it is not

[22] TASC at p. iv, p. 25 where TASC suggests the standard for DG rates is that the ensure "DG will remain a viable economic proposition for participating ratepayers", p. 26-28, Vote Solar (Kobor) at p. 28 (supporting TOU energy rates), p. 40

[23] Beach Direct at pp. 25-26

possible that unbundled demand charge structures overcharge solar customers particularly when these charges are based on costs caused by the solar class of residential customers.[24]

Further, the Vote Solar view of the cost of service study as expressed by witness Kobor confuses value and costs and misstates the basis for a test year cost of service analysis. The confusion in the testimony of witness Kobor is the basis for concluding that a cost of service study is "ill-suited to value such long-term benefits and assets." Value must be based on either cost or market. In ratemaking it is the cost that is reflected. The costs of long-term benefits and assets are included in the cost of service study based on the recovery of depreciation expense over the life of the asset and the return earned on the undepreciated asset based on market costs. These costs are only included so long as the costs were prudently incurred and the plant is used and useful.

Inclusion of solar DG as a long term asset is inconsistent with the FERC regulations associated with "as available" QF generation and on that basis has no capacity value since the solar DG customers are net users of the system at the time of the system peak production, transmission and distribution capacity. That conclusion as discussed above is consistent with the view of treating excess generation separate from the generation used to meet the customers' energy demand in real time.

[24] The same conclusion would apply to commercial customers as well so long as the demand charges are based on costs and have not been altered for some policy reason so that they no longer reflect costs.

As I have discussed above, I do not support this view of solar DG generation and thus allow for some possibility that in total solar DG capacity may have an avoided capacity cost component. In the context of the cost of service studies I have filed, there is an explicit value for solar DG capacity that may be determined from the unbundled costs. In this case, the value attributed to solar DG for production capacity is the difference between the counterfactual revenue requirement for generation (procurement demand in the cost study) and the same revenue requirement in the solar class case. That difference is the credit that accrues to solar DG based on the earned return in the TEP test year and amounts to a little over $1.5 million dollars. That value translates to almost $25 per kW of installed capacity and almost $142 per kW for the solar customers' contribution to peak load at the system peak hour in June at 5PM.[25] A cost of $142 per kW is well above the avoided capacity costs since the only additional planned capacity for the system would potentially be fast start CTs to respond to intermittent DG output on the system. This can hardly be characterized as the cost study being unable to reflect long term benefits. As an additional note, this amount would increase in a rate case context because the filed analysis only reflects the actual earned return not the allowed return.

It is certainly true that this per kW value is well above any production avoided costs in the current period and would not be inconsistent with The EIA capital cost data for an advanced combustion turbine as reported in the Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants published in April of 2013. That study

[25] Calculated as 17.4% of capacity times 61,277.33 kW solar installed or 10,681 kW CP production divided into $1.5 million dollars.

reports the cost of this facility at $660 per kW with fixed O&M at $7.04 per kW per year. If the cost of that plant is escalated at three percent per year, the 2016 capital cost would be $743 per kW installed. From this information, it is possible to see that the $ per kW is equivalent to an 11.7 percent levelized annual carrying charge rate.[26] Given the current capital structure for TEP, the 18.2% levelized carrying charge rate would require an authorized return of almost 21.5% on common equity to justify a $142 credit. Thus the avoided cost implicit in the cost study far exceeds avoided costs even if there was an immediate need for capacity and there is not. It is also likely that the actual avoided cost for capacity in the current market for power is less than the avoided cost for the least cost gas turbine because the capacity market is competitive and even for solar would be based on the option of a utility scale facility and be less than $142 per kW as well.

Q. PLEASE EXPLAIN WHAT THE DIFFERENCES IN REVENUE REQUIREMENT FOR PROCUREMENT DEMAND MEANS IN THE CONTEXT OF A RATE CASE.

A. In simplest terms, the difference between the counterfactual cost production revenue requirements and the solar class cost study production revenue requirements measures the allocated cost difference that provides a production credit to solar DG customers who would be on rates developed to reflect the solar DG class revenue requirements. The notion that cost of service studies do not provide any credit for solar DG customers is simply incorrect. Further, the fact that this credit is larger than avoided costs means

[26] Calculated as $660*(1.03^4) = $743, the required carrying charge is calculated as ($142-$7.04)/$743= 11.7%

that this study provided an additional subsidy for solar DG and does not over allocate costs to the solar DG class.

Q. IS IT UNUSUAL THAT THE IMPLIED CAPACITY CREDIT IN A COST OF SERVICE STUDY WOULD BE MORE THAN AVOIDED COSTS FOR GENERATION?

A. No. The cost of service study allocates the total system generation capacity costs. That cost includes much more than the cost of combustion turbines. Other units have much higher costs per kW than the least cost combustion turbine that represents the maximum avoided capacity cost per kW. It would not be uncommon for this cost to be a multiple of avoided costs when new capacity has been recently added to rate base. Thus the claim that the cost of service study does not credit solar DG for avoided capacity is simply false. In this case it results in a much higher credit than avoided costs. Thus we can conclude with certainty that no avoided production capacity needs to be credited to the excess generation from solar DG customers.

Q. IS IT FAIR TO CONCLUDE THAT A THREE PART, UNBUNDLED RATE RESULTING FROM THE FILED COST STUDY THAT TREATS SOLAR DG CUSTOMERS AS A SEPARATE CLASS OF CUSTOMERS IS A JUST AND REASONABLE RATE AND CONSISTENT WITH THE REQUIREMENTS OF PURPA AS CODIFIED IN THE FERC RULES?

A. Yes. Any other rate design such as those recommended by solar DG interests cannot result in just and reasonable rates for all customers and would actually result in the

1 undue discrimination claimed by solar DG advocates as an argument against both
2 separate rate class treatment and three part rates.
3
4 **Q. DOES THIS MEAN THAT THE ARGUMENT RAISED BY SOLAR**
5 **ADVOCATES THAT DG CUSTOMERS ARE JUST LIKE OTHER LOW USE**
6 **RESIDENTIAL CUSTOMERS IS INCORRECT?**
7 A. Yes. Solar DG customers actually use the system in very different ways than other low
8 use customers. First, solar DG customers have much lower load factors than other low
9 use full requirements customers. Consider for a moment a customer that installs
10 sufficient solar DG to produce an annual bill of zero kWh under net metering. That
11 customer still uses the system at night and even during the peak load hours of the day.
12 Further, the customer uses the system at the time of the system peak hour. From these
13 observations we know that the annual load factor based on coincident peak demand,
14 class NCP demand and customer NCP demand of such a solar customer is zero even
15 without knowing the demands in each of those periods. The reason is that average
16 demand is zero because of the zero annual kWh bill. Even if we assume that the bill is
17 for a modest level of net kWh typical of a small user, the load factor will be much lower
18 for a solar DG because of the higher demand of these customers and in particular the
19 higher demand requirements for the distribution system. The cost studies filed in my
20 direct testimony demonstrate conclusively that solar DG customers have higher demand
21 costs than residential customers and that if one were to use kWh charges to recover
22 those cost the solar DG customers would require energy charges over twice those of full
23 requirements customers. That fact alone indicates the absence of homogeneity for solar

DG customers with the residential class. It also shows why two-part rates that recover fixed costs in energy charges cannot possibly track costs and result in rates favor the solar DG customers through intraclass subsidies under the current rates used by the Commission.

IV. USING STANDARD COST EFFECTIVENESS TESTS TO VALUE SOLAR DG

Q. SEVERAL WITNESSES SUGGEST THE USE OF THE STANDARD COST EFFECTIVENESS TESTS USED TO EVALUATE PROGRAMS FOR IRP FILINGS AS A BASIS FOR VALUING SOLAR DG. PLEASE DESCRIBE THE COMMONLY USED TESTS.

A. Beginning in the early 1980s the California Standard Practice Manual was adopted to test conservation and energy efficiency programs. That manual was modified in the late 1980s to adopt four tests — the Participant Test, the Ratepayer Impact Test, the Total Resource Cost Test and the Societal Cost Test. The manual then specifies the components of each test. These tests are designed not to determine the value of a measure but the cost effectiveness of the various measures. Cost effectiveness is not a measure of value but is rather a screen designed to determine if a particular program produces net benefits as applicable for each test. The value of solar in the regulatory environment must be either based on the cost of service or the market value and neither of these values result from these standard tests.

Q. WHY ARE THESE TESTS NOT USEFUL IN DETERMINING THE VALUE OF SOLAR?

A. These tests were designed only to value a reduction in the kWh use over the life of an asset that has a continuous impact that is the same over time and do not include a value for the generation sent back to the system. They were also designed to reflect broad based programs that only change the pattern of load by reducing load in specific hours across the system and increase the system requirements at other hours. They are not designed to value an intermittent resource with declining output and an "as available" production resource. Further, these screening tests are not designed to value an asset across the spectrum of utility functions using different definitions of demand- CP, NCP and customer NCP. Typically the tests used for EE and DSM have the same impact on all measures on demand and that may be zero for demand in some cases. Solar DG has both positive and negative capacity impacts. It also has both positive and negative impacts on avoided energy costs as well. With these varied impacts, none of the standard tests used to evaluate EE and DSM are designed to fully develop the value of solar.

Q. IS THERE A RATE CASE METHOD FOR DETERMINING THE EQUIVALENT OF THE RATE PAYER IMPACT MEASURE?

A. Yes. The costs studies filed with my direct testimony demonstrate the ratepayer impacts in a direct calculation based on the differences in the allocated costs for residential solar DG customers and all other full requirements customers. This is especially true when the base rate revenue is added to the cost studies. It is possible to

determine the precise level of costs shifted from solar DG customers to the full requirements customers as I have discussed above. Essentially, the total impact of net metering with banking is the sum of base costs shifted as well as the energy cost shifts. The evidence shows that the full requirements customers are subsidizing the solar DG customers and that the equivalent of the RIM test would not pass this screening analysis under the current base rate design with current net metering policy. As a result, the current arrangement does not meet the purpose of PURPA that requires equitable rate treatment for customers. That treatment would be fair and equitable if solar DG customers are allocated revenue requirement based on the cost study where the solar customers are treated as a separate class for cost causation and rates were designed to recover the fully allocated costs based on the same percentage of costs paid by residential customers as a whole. In turn, those revenue requirements would be recovered in a multi-part rate including customer, demand, and TOU energy charges.

V. BUY-ALL/SELL-ALL APPROACH IS A BETTER OPTION FOR MATCHING SOLAR DG OUTPUT AND AVOIDED COSTS

Q. WHAT IS A BUY-ALL/SELL ALL APPROACH?

A. A Buy-All/Sell-All approach is the type of rate mechanisms contemplated in §292.304 (c) Rates for Purchases in the FERC PURPA regulations. In this section, the FERC mandates standard rates for purchase for QFs smaller than 100 kW. In particular, the regulations recognize that such rates may vary among technologies. By buying all the output from the solar DG facility at buy-all rate and requiring customers to buy all of

their energy from the utility at Commission approved rates both the principle of cost causation and the matching principle are satisfied. Customers receive the actual value of their generation as a credit calculated under the buy-all values that can easily reflect the value of energy and capacity separately. As discussed in detail above, the energy value would be based on short-run marginal cost and any capacity value could be fixed for a period based on a long-term avoided cost on an annual basis. Absent a contractual commitment it is not reasonable to pay a fixed cost over the entire life of solar DG.

Q. WILL USE OF BUY-ALL/SELL-ALL APPROACH BE MORE CONSISTENT WITH JUST AND REASONABLE RATES THAT ARE FAIR TO CUSTOMERS AS REQUIRED BY PURPA? PLEASE EXPLAIN.

A. Yes. By purchasing all output and valuing that output at avoided costs, customers will make better decisions related to the installed kW of the unit because the advantage of using high cost peak period energy and returning that energy at lower load and lower marginal cost periods will no longer be the same. This may also avoid the significant distribution system impact associated with delivery of excess kWh during low load periods. Under the current arrangement the incentive to zero out kWh use result in oversizing the solar DG kW by the amount calculated as DG capacity factor (about 20%) divided into the customers annual load factor. The resulting percentage is the amount needed to zero out kWh. Based on available load factor data, the capacity for solar DG is from 50% to 100% of maximum demand based on load factors between 30% and 40%. By sending the time varying price signal for energy, panel orientation

will likely change to maximize on-peak kWh production. The result will be more efficient and more economic solar DG contributions to the grid.

The payments under the sell-all approach will be based on actual marginal costs avoided. This alone will eliminate the subsidy associated with costs not actually avoided by solar DG. Under the current system of two-part rates with customer charges below customer costs, there is a significant subsidy for solar DG that exceeds avoided costs as shown by the cost studies in my direct testimony. The use of a buy-all rate would be directly based on avoided costs just as required by the PURPA regulations while all use by solar DG customers would be billed on a three part rate that recovers the class cost for solar DG customers.

VI. SERVICES PROVIDED TO SOLAR DG CUSTOMERS

Q. ARE THERE DIFFERENT VIEWS ABOUT THE SERVICES PROVIDED TO SOLAR DG CUSTOMERS?

A. Yes. Solar advocates make a number of claims about the services provided by the utility to solar DG customers. For example, TASC witness Beach denies that under net metering with banking that the utility provides a storage service even going so far as to call the storage concept a myth.[27] Witness Beach also recognizes ancillary services as an avoided cost but does not recognize the possibility that solar DG may require these same ancillary services thus causing these costs. TASC witness Beach also denies that solar DG customers require standby services. The solar advocates also fail to recognize

[27] Beach Testimony at p. 17

that all customers with generation are partial requirements customers that require, indeed select, a different set of services than full requirements customers.

Q. ON WHAT BASIS DO YOU CONCLUDE THAT SOLAR CUSTOMERS REQUIRE STANDBY SERVICE?

A. Standby service (sometimes also called breakdown service historically) is not a new or novel concept. Indeed the very origin of the concept has always been a service provided to customers with their own generation who desire to insure continuous service when that generation fails to operate. Solar DG customers require this service in a number of circumstances such as cloud cover, mechanical malfunction and outages resulting from automatic control equipment protecting the system.

The FERC Rules implementing PURPA contain §292.305 Rates for sales to qualifying facilities. That section defines four services that utilities potentially provide to solar DG QFs. Two of those services are relevant in the context of serving solar DG customers- supplemental service and back-up service (also known as standby service). There is no question that solar DG customers require both of these services. Supplemental power defined as "electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself."[28] Back-up power means "electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility."[29] Despite the claim by witness Beach that this is an

[28] §292.101 Definitions, (b) (8)
[29] §292.101 Definitions, (b) (9)

identical service provided to a regular customer who changes the normal usage pattern to increase load in a low load period, that claim is incorrect because that random event is accounted for by the fact that the system deals with the issue based on the diversity of thousands of customers. Solar DG customers' loads are impacted by the effects that are common for all customers in a geographic area resulting in no diversity of the impact. It is this absence of any diversity related to production that distinguishes the solar intermittency from customers who use power in different patterns from the average for the population. Further, when the load is low as in the case that witness Beach describes at pages 15 and 16 of direct testimony, the added load is very small from the change that includes lights, computer and a small appliance. The solar load change in the same period is multiples of the change in load because it goes from full to zero output along with every other solar DG customer served on that same circuit causing voltage to drop significantly as the utility service is called on to meet all the loads previously served by solar DG. This is truly a standby service.

Q. DOES THE UTILITY PROVIDE A VIRTUAL STORAGE SERVICE FOR SOLAR DG UNDER THE BANKING PROVISION?

A. Yes. The concept of banking has its origins in the nomination and delivery of natural gas to end use customers. The daily nominations for customers seldom matched the actual daily gas consumed. Customers were allowed to address this mismatch on a daily basis through a separate banking service. Under that service, excess deliveries were credited to the account of the customer to offset the under deliveries that occurred on another day. At the end of the month, the bank was cashed out. This banking

service was often referred to as a storage service even though no physical storage was used. The virtual storage used by solar DG customers is when one or more kWhs are recorded to the account of a customer and become available for later use on a one for one basis for power delivered by the utility to the customer. (I will not discuss the storage arbitrage issue or the facts that there are losses associated with both the delivery to the utility and the delivery back to the customer as these topics are covered in my direct testimony.) The virtual storage concept is also used within a month when excess generation during the high production hours is used in the nighttime hours to offset the current bill. This is equivalent of a daily balancing concept with supplemental daily service provided by the utility when the customer has a non-positive storage balance for the month.

To claim that the banking provision is not storage is to deny the physical reality of the service. A kwh is delivered physically from solar DG to the utility as recorded by the meter turning backward and that kWh is physically delivered back to the solar DG customer from a utility owned resource when the meter turns forward to record the utility delivery.

Q. DO SOLAR DG CUSTOMERS REQUIRE ANCILLARY SERVICES?

A. Yes. In particular solar DG typically requires reactive power, voltage control, frequency control, spinning reserves and operating reserves. These services are not free and the added cost for these services that result from current installations of solar DG should properly be paid by the solar DG class. The requirement for these services arises with

current technology because inverters in the typical solar DG installation do not provide ancillary services but do use them. As the penetration of solar DG increases, the requirement for both spinning and operating reserves increases in large part due to the combination of intermittency and the absence of diversity related to solar insolation. The TEP OATT spells out the cost of these services in various schedules of the tariff.

Q. HAVE YOU EXPLAINED THE CONCEPTS OF FULL AND PARTIAL REQUIREMENTS CUSTOMERS IN THIS CASE?

A. Yes. I have provided a full explanation of these services in my direct testimony at pages 11-16. I will not repeat that discussion here, except to note that these partial requirements solar DG customers must be treated as a separate class of service in order to have just and reasonable rates that are non-discriminatory. TASC witness Beach has provided no evidence to support his views on appropriate rates for solar DG customers.

VII. MISCELLANEOUS ISSUES

Q. TASC WITNESS BEACH STATES AT PAGE 14 THAT THE EXPORT COST OF POWER IS THE UTILITY COST. PLEASE COMMENT.

A. There is no suggestion that the cost of the physical export of power be charged an export rate. As for cost causation, the facilities serving the solar DG customer must be designed for the greater of the customer peak load or the customer peak delivery. In this case the peak delivery is greater than the peak load by almost two to one. Witness Beach acknowledges that the customer generator is responsible for interconnection

costs and the allocation of costs based on solar DG class NCP is fully consistent with cost causation and witness Beach's view of cost responsibility. Similarly, it should be directly recognized that the actual kWh delivered to the system is less than the metered kWh delivered to the utility as a result of losses. Since the utility is providing the delivery service the number of kWhs should be reduced by losses to reflect the actual kWhs available for delivery. This is common practice in the electric industry to reduce the number of kWhs delivered to the system by the difference in losses between the receipt point and the delivery point or points as I have demonstrated in my direct testimony. The higher the penetration of solar DG on a circuit the higher the delivery losses will be. And in no event are the losses from receipt point to delivery point ever zero.

Q. TASC WITNESS BEACH STATES AT PAGE 14 THAT THE SOLAR DG CUSTOMERS PAYS FULLY FOR THE USE OF THE SYSTEM JUST THE SAME AS ANY OTHER CUSTOMER. PLEASE COMMENT.

A. This statement is simply wrong. A customer with a net zero kWh bill pays only $120 in the year for all of the use of the grid and that does not even cover customer costs. In order for the statement to be true, avoided costs must be greater than the total costs to serve the DG customer. The cost of service studies in my direct testimony prove that is not the case. Further, under the FERC regulations implementing PURPA, the avoided energy cost is only the short-run avoided costs; and the avoided capital cost cannot include all of the adders that the solar DG witnesses seek to include, because the avoided capacity costs cannot exceed the actual avoided costs as I have noted above.

Given that we know the market value of DG (the value may be calculated as the difference between the latest utility scale solar DG winning bid price less the levelized cost of energy since the remainder is the implied market capacity value for solar DG), that calculated capacity value is even lower than avoided costs calculated on a least cost combustion turbine and it makes no sense from a policy perspective to pay more for solar DG than the market value. Doing so only enriches the rent seekers representing the solar sellers and installers at the expense of customers who do not have a solar option.

Q. VOTE SOLAR WITNESS VOLKMANN RECOMMENDS THE USE OF SMART INVERTERS FOR DG SOLAR AND STORAGE. PLEASE COMMENT.

A. I agree that smart inverter technology coupled with improved communication between the utility and the customers inverter is a positive approach to improving integration of solar DG. A requirement for both new solar DG and for existing solar DG as inverters are replaced will improve efficiency and operation at the expense of fewer kWh. With this requirement there must also be changes that provide better price signals to customers so that these inverters actually have value for the system. As an example, utility rates typically have power factor adjustment provisions in rates and those would provide a mechanism for charging low power factor customers.

Q. WITNESS VOLKMANN ALSO RECOMMENDS THAT A DETAILED MARGINAL COST STUDY OF TRANSMISSION AND DISTRIBUTION BE REQUIRED FOR EACH UTILITY. PLEASE COMMENT.

A. Having prepared a number of electric marginal cost studies for all of the utility costs including production, transmission, distribution and customer components, I believe such studies are useful as they relate to rate design. They are not useful for calculating avoided costs for transmission and distribution. As I have discussed above, marginal costs are not the same for an increment and a decrement of load. In many cases, a decrement of load has an avoided cost of zero because of the lumpy characteristics of utility assets. It is not likely that a small change in load on a circuit will allow the utility to save any capital costs currently and not even in the future unless the incremental reduction is sufficient to allow the next smallest size of equipment to replace the current installation. Consider for example that the energy saving (kW and kWh) may not equal the full technical savings because of the income effect on demand. That is, solar DG that lowers the cost of electric service will have an income effect on demand. That income effect may result in increased consumption based on keeping the premise cooler for example. If that is the case, capacity savings may well be lower than would have occurred with no change in comfort. In that case, there may be no net capacity saving at all.

In a marginal cost study, the typical approach is to add an increment of load that is typically at the periphery of the system. In that case, the costs could not be avoided by

solar DG in any event so the value of a marginal cost study is not for use as a measure of avoided costs but for sending better price signals.

Q. ARE THERE LOCATION SPECIFIC BENEFITS FOR SOLAR DG AND OTHER DER PROGRAMS AS SUGGESTED BY VOTE SOLAR WITNESS VOLKMANN?

A. Yes. There may be parts of the system that over time have had growth that differs from the original expectations when the system was built. In that case it may be that added system capacity may be avoided by strategically placed increments of solar DG or other DER resources. By identifying these portions of the system and the optimal location solar developers may bid to locate at a site and receive a larger capacity credit than would be available for a general site on the system. The use of competitive bidding for these locations is consistent with least cost planning across the spectrum of utility resources. Witness Volkmann cites this type of process in his direct testimony.[30]

Q. WITNESS VOLKMANN ARGUES THAT SOLAR DG CAN AVOID SERVICE INTERRUPTIONS (DIRECT AT PAGE 27). PLEASE COMMENT.

A. I assume that this a theoretical statement since current IEEE regulations require solar to disconnect from the grid when there is an outage. The concept of islanding the system is being addressed, but to provide service during an outage is more complex than concluding solar DG can avoid service disruptions as a general conclusion. The key point is that depending on the load the solar DG would trip off because the load is too large in aggregate to be served by the DG capacity resulting in under voltage; or in the

[30] Volkmann Direct, p. 31

other extreme, there is not enough load to use the generation and the system trips off because of over voltage. While certain of these conditions change with smart inverters the current configuration does not increase system reliability.

Q. DO YOU AGREE WITH WITNESS VOLKMANN THAT DISTRIBUTION SYSTEM PLANNING MUST CHANGE?

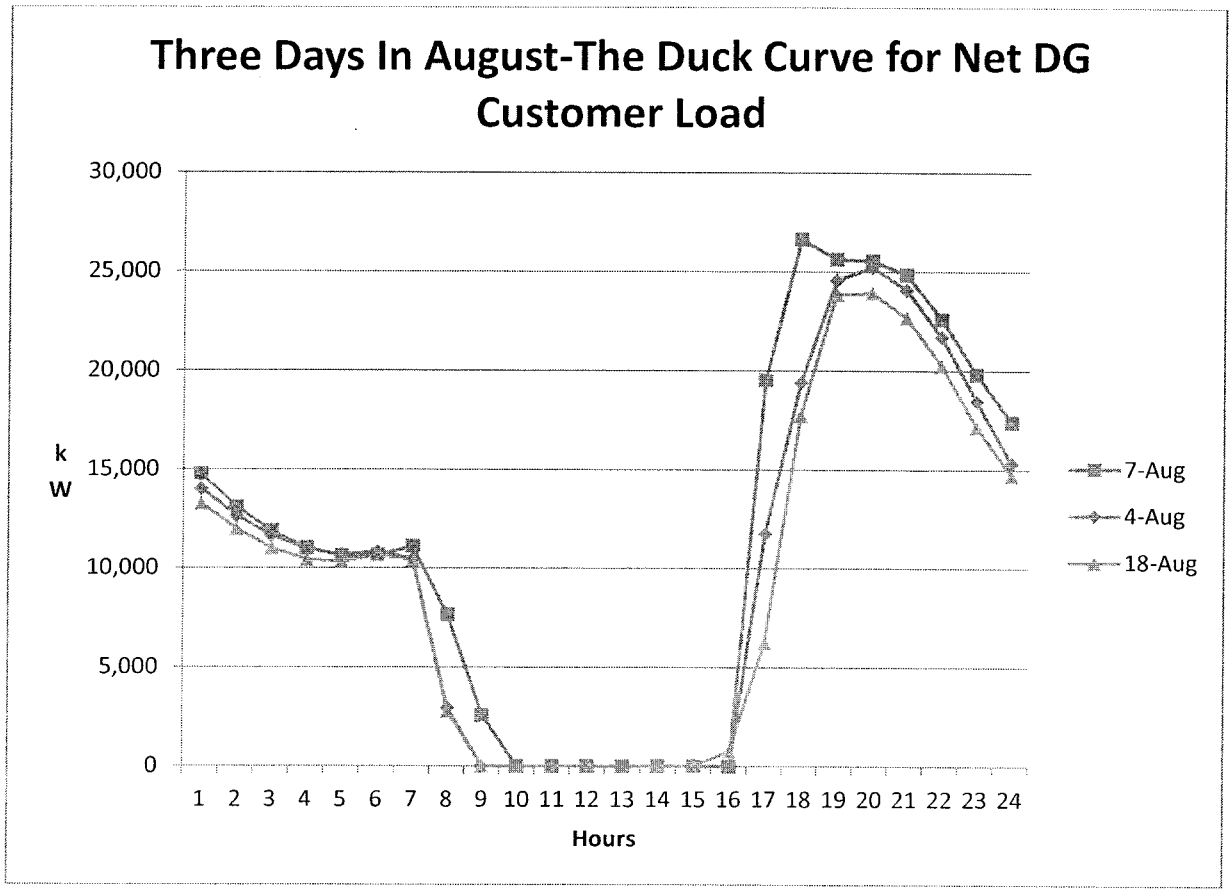
A. Yes. The impact of two way flow on systems designed for one way flow requires that engineers respond in ways that improve the overall efficiency and economics of the grid. The status quo is no longer an adequate set of considerations. By using available technology and improved communications protocols the power delivery system can accommodate the changing market dynamics. Although not mentioned by witness Volkmann it is likely that, in response to two ways flow from DG systems, delivery services will need to be modified in ways that will require increased investment in infrastructure. Regulations should be developed to permit this investment with tools such as infrastructure adjustment clauses designed to permit timely recovery of these costs under plans approved for each utility.

Q. WITNESS KOBOR STATES (DIRECT AT PAGE 9) THAT THE ONLY DIFFERENCE BETWEEN SOLAR DG AND ENERGY EFFICIENCY IS THE EXPORT OF POWER. PLEASE COMMENT.

A. The premise for this statement is false. Solar DG is very different than energy efficiency that reduces kWh consumption. By improving efficiency for end-use applications customers reduce load over the entire load shape of that particular end use.

By reducing use with solar DG (ignoring for a moment the excess generation), solar DG only changes the end-use applications during hours with sufficient insolation for the solar DG to operate. There is no **continuous** adjustment to load but rather a non-diversified demand adjustment in some hours and the adjustment for each individual premise are intermittent. The modification of the load shape is shown in Figure 1 below.

Figure 1



This curve shows how solar DG changes the customer net load shape. The change is far different from EE changes that would be uniform and consistent across all hours that the EE changes impact hourly load for the end-use. In fact, for two of the three days in the sample the peak occurs at hour ending 8 PM. Unlike EE, solar DG cannot be counted

on for a uniform reduction of load in all hours nor can it be counted on for reduced load on a consistent basis in any particular hour.

When the added issue of power delivery to the utility system is added, the evidence shows that this represents the peak load on delivery system resources. Adding that difference to the list of reasons solar DG is very different than EE investments.

Q. WITNESS KOBOR STATES THAT THE CENTRAL QUESTION FOR DECISION IN THIS CASE IS WHETHER THE PRICE PAID FOR DG EXPORTS APPROPRIATELY REFLECTS THE VALUE OF THE ENERGY PROVIDED?[31] PLEASE COMMENT.

A. While I would like to agree, as I have noted above this position is not consistent with the PURPA FERC Rules. Under PURPA the avoided energy costs for an "as available" resource is the current period marginal cost as I have explained. However, the full value of the resource may also include a capacity component and that should be recognized. It is particularly important that the capacity value be part of the IRP assessment of rooftop solar DG as part of the resource mix to develop a least cost plan for each utility system. If that is the least cost option then it should remain as part of the mix regardless of other provisions. If it is not a least cost alternative its value will be solely to meet any mandated requirements for the technology and no more.

[31] Kobor Direct p. 4

1 **Q. WITNESS KOBOR RECOMMENDS A THIRD PARTY EVALUATION OF**
2 **AVOIDED COSTS (DIRECT AT PAGES 5 AND 48). DO YOU BELIEVE THAT**
3 **PROCESS IS NECESSARY?**
4 A. No. Utilities have made these estimates since the early 1980s and the methodology is
5 broadly understood within the industry and the FERC regulations implementing
6 PURPA provide clear benchmarks about the definition and determination of avoided
7 costs. There is no inherent reason for each utility to incur the expense of funding a third
8 party to make calculations the utility makes regularly and present to the Commission on
9 a regular basis as well. I would note that rent seeking is not just an exercise for the
10 solar DG industry but is also possible that consultants engage in the same practice.
11
12 **Q. IS THE USE OF NET METERING AS A PROXY FOR SOLAR DG AVOIDED**
13 **COSTS LOGICAL?**
14 A. While witness Kobor makes this claim[32], there is no sound logic in support of net
15 metering, a point recognized by even solar advocates when the process is referred to as
16 "rough justice". As a general rule, utilities are so different that using this simple one
17 size fits all approach cannot be justified as logical. This is a concept that witness Kobor
18 confirms in her testimony.[33] For example, utilities that peak when there is no sunlight
19 (there a significant number that have peaks in the winter morning or evening) have no
20 capacity savings of any sort but all incur capacity costs for production, transmission and
21 distribution that are included in base rates.
22

[32] Op. cit. p. 7
[33] Op. cit. p. 8 lines 8-9

I note above that the embedded cost of service credit for solar DG based on the TEP cost study far exceeds avoided costs based on actual solar DG output and avoided capacity costs. The correct logic would be pay credits based on the utilities actual avoided costs-short-run energy and long-run capacity.

Q. DOES THE COMPARISON OF AVOIDED COST STUDIES OVER TIME HAVE ANY VALUE RELATED TO METHODOLOGY OR ANALYSIS OF DIFFERENCES?

A. Witness Kobor seems to believe that the differences in studies over time and by different parties requires Commission guidance on studies even though she failed to do any basic due diligence related to the differences. At page 15 of witness Kobor's direct testimony she provides a table that reports on three studies done in two different periods and by three different parties for the same Arizona utility company. For the studies completed four year apart by essentially the same entity the results are dramatically different. The differences can be largely explained by two factors- lower natural gas prices delivered to electric generation and the excess generation capacity in the market.

As for the third study there are numerous errors related to the calculation of avoided costs. I have discussed these errors above and will not repeat that discussion except to note that the avoided CT costs are not based on the least expensive capital addition which is far less than the technology of the selected CT based on the Crossborder Energy filing in this case based on EIA data. Other factors are too high as well such as fixed O&M, the applicable carrying charge rate and in the case of TEP and UNSE the

net dependable capacity at the time of the system peak. The end result is that errors of including costs not avoided based under the FERC definition, using an incorrect methodology for avoided T&D costs and the inflated values of the components of the equation leads to a conclusion that the Crossborder study differences are likely the result of numerous inaccuracies in the estimation procedure.

The evidence does not support the need for Commission guidance so much for utilities who perform these calculations in planning studies but for the solar DG advocates who have developed and used methods that are not theoretically or practically sound and do not comply with the simple language of the FERC rules implementing PURPA requirements that proscribe the utilities actual avoided costs but for the solar DG capacity.

Q. SEVERAL SOLAR DG WITNESS RECOMMEND USING CAPACITY COSTS ON A CONTINUOUS BASIS. IS THAT A SOUND APPROACH?

A. No. That approach will never get the avoided capacity costs correct simply because it assumes that capacity additions are continuous. They are not. It may be an inconvenient fact that additions are lumpy, but it is a fact. There is no avoided capacity value based on a continuous analysis.

Q. WITNESS KOBOR OPINES THAT SOLAR DG EXPORTS OCCUR "DURING HEAVIER LOADING PERIODS".[34] IS THAT STATEMENT CORRECT?

A. No. This statement does not comport with the evidence in Exhibit HEO-1 from my direct testimony that shows solar DG production uniformly does not match heavier load periods. Couple that with the fact that Figure 1 above shows that in the highest cost summer hours the solar DG customer is consuming utility supplied kWhs not exporting. Exhibit HEO-2 from my direct further confirms that solar production does not match high cost periods in either season. Exports are greatest when loads are lowest both for customers and the system.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS.

A. My conclusions may be summarized as follows:

1. The determination of avoided costs is not some new process since under PURPA both utilities and Commissions have made these calculations since the 1980s.
2. Avoided costs do not require any speculation related to externalities that have not been internalized. If the utility does not pay the cost it cannot be avoided cost. While these externalities may be considered as part of an IRP process which screens alternatives, they cannot be part of a payment to solar DG customers because it becomes a tax on non-solar customers for the benefit of solar DG customers.

[34] Kobor Direct, p. 29

3. The FERC Rules implementing PURPA provide for energy avoided cost on a short-run basis for intermittent resources such as solar DG. Long-run avoided energy costs may only be elected, not mandated, for an enforceable long-term contractual commitment.
4. Discount rates for utility avoided capacity cost must be based on the weighted average marginal cost of capital.
5. Social discount rates are not appropriate for calculating avoided private costs and all utility costs that can be avoided by a utility are private costs.
6. Marginal cost for an increment of load and a decrement of load are not the same.
7. Marginal T&D costs cannot be estimated with regression analysis because there is no measure of capacity available to use as the dependent variable because there are multiple measures of capacity.
8. Delaying capacity additions as a measure of avoided costs is a much smaller value than actually avoiding the cost.
9. Market based determination of avoided cost is superior to estimating avoided costs and is consistent with the current position of the FERC in its avoided cost rules.
10. The cost of service studies filed in this case support separate rate treatment for solar DG customers under the fully unbundled three part rate with separate cost based seasonal and TOU energy charges not encumbered with fixed cost recover.

11. The combination of the counterfactual cost study and the solar class subsidy prove that a cost studies do reflect capacity cost savings for solar DG customers and those savings exceed avoided costs.
12. The FERC Rules require just and reasonable rates for sales to solar DG customers based on consistent system wide cost allocations. This is exactly the method used in my cost studies filed in direct testimony and shown in the solar DG class study.
13. The cost studies filed in my direct testimony demonstrate that there is an embedded cost credit for generation capacity in excess of avoided costs when calculating the revenue requirements for the solar class. This results in an explicit subsidy based on system wide costing principles.
14. Solar DG customers do not have the same characteristics of low use full requirements customers. They have much lower load factors.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations remain unchanged from those in my direct testimony. In addition, I recommend that avoided costs be calculated consistent with the FERC rules promulgated to implement the various provisions of PURPA as amended over time. This would include treating avoided energy costs based on the same time period as the rates effective for sales to customers. In the alternative these rates could be calculated annually and paid for all excess generation when it is delivered to the system. Finally, I recommend that IRP screening tests such as the Rate Impact Measure, Total Resource Cost or Social Cost Tests be rejected as a means to value solar DG but continue to be

used to screen resource options under the IRP. It should be incumbent on the utility to develop a best cost plan consistent with legislative mandates as they may be changed from time to time.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.