PUBLIC SERVICE COMMISSION OF UTAH

Docket No. 13-035-184

Exhibit SC___DRM-3

PV Payback Model

PV Payback Model

Methods for model of the penalty to existing and potential NEM customers resulting from proposed fixed charges

To arrive at our conclusions, we developed a straightforward methodology, based on standard assumptions, to determine the payback period of distributed generation with and without RMP's proposed increased customer charge and proposed NEM charge. We began by constructing revenue neutral alternate proposed rates without fixed charges using the following steps and data from RMP testimony[1]. We first summed the total expected revenue from both the customer charge increase and the NEM charge. Assuming that this revenue was not recovered through fixed charges but rather through variable kWh rates, we divided this total expected revenue by the total kWh consumed by the residential class to determine how much rates would increase if the fixed charges were not applied (Table YY, and Table YZ). We then added these amounts to the proposed RMP tiered rates to produce three alternate rate structure: one without the customer charge increase, one without the NEM charge, and one without both fixed charges (Table XX).

Table B1. Alternative Revenue Neutral Proposed Rates Based on RMP's Proposed Rates without Increased Customer Charges

Alternate Revenue Neutral Proposed Rates Based on RMP's Proposed Rates without increased Customer and NEM charges (Based on Exhibit RMP_(JRS-5))

	Forecasted Units	Present Price	Present Revenue Dollars	Forecasted Revenue Dollars	RMP Proposed Price	RMP Proposed Revenue Dollars	Proposed: Without Customer Charge Increase Proposed Price	Proposed: Without Customer Charge Increase Revenue Dollars	Proposed: Without NEM Charge Proposed Price	Proposed: Without NEM Charge Revenue Dollars	Proposed: Without Customer Charge Increase or NEM Charge Proposed Price	Proposed: Without Customer Charge Increase or NEM Charge Revenue Dollars
Schedule No. 1- Residential Service												
Total Customer	8,511,800											
Customer Charge - 1 Phase	8,398,777	$5.00	$40,893,779	$41,993,885	$8.00	$67,190,216	$5	$41,993,885	$8.00	$67,190,216	$5	$41,993,885
Customer Charge - 3 Phase	14,094	$10.00	$137,247	$140,940	$16.00	$225,504	$10	$140,940	$16.00	$225,504	$10	$140,940
Net Metering Facilities Charge	23,932				$4.25	$101,711	$4.25	$101,711	$0	$0	$0.00	$0
First 400 kWh (May-Sept)	1,274,636,742	8.8498	$110,655,425	$112,802,802	8.9412	$113,967,820	9.3668	$119,393,276	8.9429	$113,989,458	9.3685	$119,414,913
Next 600 kWh (May-Sept)	1,040,456,011	11.5429	$121,256,955	$120,098,797	11.6621	$121,339,020	12.0877	$125,767,692	11.6638	$121,356,683	12.0894	$125,785,354
All add'l kWh (May-Sept)	358,873,906	14.4508	$69,539,699	$51,860,150	14.6000	$52,395,590	15.0256	$53,923,127	14.6017	$52,401,682	15.0273	$53,929,219
All kWh (Oct-Apr)												
First 400 kWh (Oct-Apr)	1,613,094,234	8.8498	$149,113,357	$142,755,614	8.9412	*$144,229,982*	9.3668	$151,096,072	8.9429	$144,257,364	9.3685	$151,123,454
All add'l kWh (Oct-Apr)	1,704,644,903	9.8913	$176,151,155	$168,611,541	9.9934	*$170,351,984*	10.4190	$177,607,757	9.9951	$170,380,921	10.4207	$177,636,694
Minimum 1 Phase	98,763	$7.00	$673,230	$691,341	$15.00	$1,481,445	$15.00	$1,481,445	$15.00	$1,481,445	$15.00	$1,481,445
Minimum 3 Phase	166	$14.00	$2,264	$2,324	$30.00	$4,980	$30.00	$4,980	$30.00	$4,980	$30.00	$4,980
Minimum Seasonal	0	$84.00	$0	$0	$180.00	$0	$180.00	$0	$180.00	$0	$180.00	$0
kWh in Minimum	501,472											
kWh in Minimum - Summer	223,485											
kWh in Minimum - Winter	277,987											
Unbilled	0		$1,515,669	$0		$0						
Total	5,992,207,269		$669,938,780	$638,957,394		$671,288,252		$671,510,884		$671,288,252		$671,510,884
Schedule No. 3- Residential Service - Low Income Lifeline Program												
Total Customer	370,465											
Customer Charge - 1 Phase	369,457	$5.00	$1,747,206	$1,847,285	$8.00	$2,955,656	$5	$1,847,285	$5	$2,955,656	$5	$1,847,285
Customer Charge - 3 Phase	257	$10.00	$2,433	$2,570	$16.00	$4,112	$10	$2,570	$10	$4,112	$10	$2,570
Net Metering Facilities Charge	0				$4.25	$0	$0.00	$0	$0	$0	$0	$0
First 400 kWh (May-Sept)	47,435,117	8.8498	$4,447,867	$4,197,913	8.9412	$4,241,269	9.3668	$4,443,175	$8.9412	$4,241,269	$9.3668	$4,443,175
Next 600 kWh (May-Sept)	31,907,309	11.5429	$3,989,465	$3,683,029	11.6621	$3,721,062	12.0877	$3,856,875	$11.6621	$3,721,062	$12.0877	$3,856,875
All add'l kWh (May-Sept)	10,205,740	14.4508	$1,694,581	$1,474,811	14.6000	$1,490,038	15.0256	$1,533,478	$14.6000	$1,490,038	$15.0256	$1,533,478
All kWh (Oct-Apr)												
First 400 kWh (Oct-Apr)	64,598,419	8.8498	$6,106,541	$5,716,831	*8.9412*	*$5,775,874*	9.3668	$6,050,835	$8.9412	$5,775,874	$9.3668	$6,050,835
All add'l kWh (Oct-Apr)	54,308,077	9.8913	$5,738,159	$5,371,775	*9.9934*	*$5,427,223*	10.4190	$5,658,384	$9.9934	$5,427,223	$10.4190	$5,658,384
Minimum 1 Phase	751	$7.00	$4,970	$5,257	$15.00	$11,265	$15.00	$11,265	$15	$11,265	$15	$11,265
Minimum 3 Phase	0	$14.00	$0	$0	$30.00	$0	$30.00	$0	$30	$0	$30	$0
Minimum Seasonal	0	$84.00	$0	$0	$180.00	$0	$180.00	$0	$180	$0	$180	$0
kWh in Minimum	4,249											
kWh in Minimum - Summer	2,043											
kWh in Minimum - Winter	2,206											
Unbilled	0		$53,425	$0		$0						
Total	208,458,911		$23,784,647	$22,299,471		$23,626,499		$23,403,868		$23,626,499		$23,403,868
Total (Non-Lifeline and Lifeline)						$ 694,914,751		$ 694,914,752		$ 694,914,752	$ -	$ 694,914,752

[1] Exhibit RMP_(JRS-5)

Table B2. Values used to calculate per kWh cost of increased customer and NEM charges

Non-Lifeline total expected revenue from increased customer charge (1 phase)	$	25,196,331
Non-Lifeline total expected revenue from increased customer charge (3 phase)	$	84,564
Lifeline total expected revenue from increased customer charge (1 phase)	$	1,108,371
Lifeline total expected revenue from increased customer charge (3 phase)	$	1,542
Total expected revenue from increased customer charge	$	26,390,808
Total expected revenue from NEM charge	$	101,711
Non-lifeline total forecasted kWh		5,991,705,796
Lifeline forecasted total kWh		208,454,662
Cost/kWh of increase customer charge	$	0.4256472
Cost/kWh of NEM charge	$	0.0016975

Table B3. RMP proposed and alternate proposed rates used in analysis

	RMP Proposed Rates	No Increase in Customer Charge	No NEM Charge	No Increase Customer or NEM Charge
Tier 1 Summer	0.08941	0.09367	0.08943	0.09369
Tier 2 Summer	0.11662	0.12088	0.11664	0.12089
Tier 3 Summer	0.14600	0.15026	0.14602	0.15027
Tier 1 Winter	0.08941	0.09367	0.08943	0.09369
Tier 2 Winter	0.09993	0.10419	0.09995	0.10421
Customer Charge	8.0	5.0	8.0	5.0
NEM Charge	4.25	4.25	0	0
Minimum Charge	15.0	15.0	15.0	15.0
Lifeline Credit	12.6	12.6	12.6	12.6

We used information provided by RMP in Sierra Club's Data Request 5.1 to compute an expected bill for average customers at each 25 kWh increment of average monthly usage. We averaged usage over the three years of data provided for each 25 kWh increment, computed tiered usage based RMP's rate schedules, and then computed an annual bill under each rate scenario using tiered usage information.

To use the data provided RMP, some additional analysis was required. Because the data provided by RMP lumped non-submetered units from multi-family accounts into a single record, and because RMP's residential rate structures [add quote from rate doc], we were forced to implement a methodology to remove records that were likely multi-family residences. Our approach removes the variance we believe is in the sample due to the inclusion of multifamily residences by taking the standard deviation of the observations, where each observation is the number of households in each average consumption bin. We removed bins whose number of customers is less than this standard deviation, resulting in an upper boundary of 1300 kWh of average monthly usage for the

sample[2]. We are confident in this approach because, in similar analysis we have completed, we found that only 3% of Southern California Edison customers consume above this boundary. In addition, according to the EIA the average monthly consumption for households in Utah is 793 kWh.[3] Implicit in this analysis is the assumption that the distribution of household consumption does not have a tail as fat/skewed as the one we received, and so what we have done is trimmed that tail.

The next step in our analysis was to sized a solar PV system for average customers at each 25 kWh increment, assuming that customers would install a system that generates an amount equivalent to annual consumption. We computed a weighted average solar insolation rate for the state of Utah (1,399 kWh/kW -year), based on insolation values per county, the share of existing solar installations per county, and a conversion of kWh/m^2 day to kWh/kW-year using the default values for NREL's PV Watts calculation tool.

Next, we computed a range of expected cost of each PV system, based on the solar sizing, a range of $/watt installed values from $3–$6, the 30% federal tax incentive, and the 2015 RMP solar incentive amounts for each size class. We also included the cost of purchasing electricity to account for a 1% annual degradation rate in PV electricity generation.

Using this information, we calculated the simple payback period for each average customer under each of the four rate scenarios. We conducted five runs of this analysis for varying cost per installed watt values, increments of $1 from $3–$6. We conducted this sensitivity to account for the changing cost of solar installations. Current California Solar Initiative (CSI) data, which is one of the more consistent and reliable sources, shows an average cost per installed watt of $5.80 in California[4], so we assume that $6 is the upper limit. The SunShot goal for 2020 is $1.50/watt for residential[5], but this is still several years away, and we argue that $3/watt is the lowest reasonable value in the near term. Overall, we assume $3-$5 per watt is the most likely range, but included $6 as sensitivity because of the rumored expiration of Federal investment tax credit for PV after 2016.

While several of our model assumptions could be subject to debate, our sensitivity analysis shows that modifying these assumptions would not alter our overall conclusions, since these assumptions affect the magnitude, but not the relative impact, of rate scenarios on the incentive to install distributed solar PV.

[2] This described the approach implemented for non-Lifeline customers. The same method was used for Lifeline customers and yielded a cutoff of 1075 kWh. For the sake of consistency in the analysis, we used 1300 kWh as the cutoff for Lifeline customers as well.
[3] Energy Information Agency. 2012 Utah Electricity Profile. http://www.eia.gov/electricity/state/utah/
[4] This is based on a one year rolling average of CSI data, http://www.californiasolarstatistics.ca.gov/ (Accessed March 31, 2014).
[5] Department of Energy. SunShot Vision Study. http://energy.gov/eere/sunshot/sunshot-vision-study