Before the
Public Service Commission of Utah

In The Matter of the Investigation of the)
Costs and Benefits of Pacificorp's Net)
Metering Program)

Docket No. 14-035-114

Direct Testimony of
Melissa Whited

On the Topic of
Net Metering Tariffs

On Behalf of
Utah Clean Energy

June 8, 2017

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Melissa Whited. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have six years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, rate design, policies to address distributed energy resources (DER), and market power. I have analyzed rate design issues pertaining to DERs for proceedings in Massachusetts, Colorado, New York, Utah, Nevada, Wisconsin, Hawaii, and Maryland. In 2015, I presented to the Utah Net Energy Metering Workgroup on rate design options for customers with distributed generation. I have sponsored testimony before the Massachusetts Department of Public Utilities, the Hawaii Public Utilities Commission, the Public Utility Commission of Texas, and the Federal Energy Regulatory Commission.

I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. Prior to rejoining Synapse, I published in the *Journal of Regional Analysis and Policy* regarding the economic impacts of water transfers, analyzed state water efficiency policies while at the Wisconsin Public Service Commission, and conducted econometric analyses of energy efficiency cost-effectiveness. My resume is attached as Schedule MW-1.

Q. On whose behalf are you testifying in this case?

A. I am providing evidence on behalf of Utah Clean Energy.

Q. Have you previously testified before the Utah Public Service Commission?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and critique the Company's proposed new rates for customers with distributed generation (the Company's proposed Schedule 5).

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your primary findings.

A. I make the following findings:

- The Company's proposed tariff for residential customers with distributed generation would reduce the economics of distributed generation so dramatically that few residential customers, if any, will install distributed generation in the future.

- Demand charges are not suited for residential customers – including net metering customers – because they do not adhere to the basic ratemaking principles of efficiency, simplicity, stability, and fairness.

- Customers with distributed generation should not be placed in a separate rate class, because this is not justified by their load characteristics, would only serve to increase costs to non-net metered customers, and is not sustainable over the long-term.

Q. Please summarize your recommendations regarding the Company's proposed rate design for residential customers with distributed generation.

A. I recommend the following:

- The Commission should not approve any distributed generation rate design that essentially eliminates any economic advantage for residential customers to install distributed generation. Therefore, the Commission should reject the Company's rate design proposal.

- The Commission should make a finding that demand charges are not well-suited to residential customers.

- The Commission should make a finding that compensation for customers with distributed generation should strike a balance between enabling reasonable growth in distributed generation, while mitigating cost-shifting to non-net metered customers.

- The Commission should make a finding that compensation for distributed generation can be modified over time, to maintain this balance as conditions change.

- If the Commission determines that it is reasonable to modify the current tariff for residential customers with distributed generation, I recommend that only the compensation for monthly net excess generation be reduced. That is, only the credit for kilowatt-hours of generation remaining after consumption has been netted from generation at the end of the monthly billing period should be changed. The payment for monthly net excess generation should be based on the best estimate of long-term net benefits, including the benefits of avoiding large capital investments.

3. THE COMPANY'S PROPOSAL

Q. Please describe the Legislature's requirements set forth in Utah Code Ann. § 54-15-105.1.

A. The statute requires the Commission to

(1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and

(2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits.

Q. Please describe the Company's Compliance Filing.

A. On November 9, 2016, Rocky Mountain Power (RMP) submitted its compliance filing in response to the Commission's November 10, 2015 order.[1] In its filing, the Company claims that the analysis demonstrates that NEM costs exceed the benefits, rendering the current rate structure unjust and unreasonable because costs are shifted. Because of this, the Company requests that:

1. The Commission approve RMP's proposed three-part tariff for NEM customers,
2. The Commission approve new application fees for net metering customers, and
3. Net metering customers be segregated into a distinct rate class.

Q. What compensation mechanism is the Company proposing for residential customers with distributed generation?

A. The Company is proposing to continue net metering, but to significantly alter the underlying rate design. Specifically, the Company is proposing a rate design for residential net metering customers that consists of a higher customer charge, a demand charge, and a reduced energy charge. Under the Company's proposed Schedule 5, new NEM customers would face an increase in the fixed charge of 150% (from $6.00 to

[1] PSC, Order, In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, November 10, 2015.

$15.00 for single phase customers); a demand charge based on maximum hourly usage; and an energy rate less than half the current rate. This is shown in the table below.

Table 1. Current and Proposed Residential Rates

		Current	Proposed	
Customer Charge		$6.00 (single phase) $12.00 (three phase)	$15.00 $30.00	(single phase) (three phase)
Demand Charge ($/kW)	Summer		$9.02	Weekdays, 3pm – 8pm
	Winter			Weekdays, 8 am – 10 am, 3 pm – 8pm
Energy Charge ($/kWh)	Summer (May–Sep)	$0.085 first 400 kWh $0.115 next 600 kWh $0.145 additional kWh	$0.038	
	Winter (Oct–Apr)	$0.085 first 400 kWh $0.107 additional kWh		

Q. What increases in application fees is the Company proposing?

A. The Company is proposing to introduce an application fee for Level 1 customers of $60, while increasing application fees for Level 2 and Level 3 customers. Level 2 customers would see an increase of $25, plus $1 for each kW. Level 3 customers would see an increase of $50, plus $1.50 per kW. These proposed increases to the application fees are summarized in Ms. Steward's table, reproduced below.[2]

Table 2. Proposed Increases in NEM Application Fees

Net Metering Application Fees		
	Current	**Proposed**
Level 1	0	$60
Level 2	$50	$75
per kW	$1.00	$1.50
Level 3	$100	$150
per kW	$2.00	$3.00

[2] Direct Testimony of Joelle Steward, Table 7, November 2016, page 34

Q. What is the Company proposing with respect to a separate rate class?

A. The Company is proposing to segregate residential customers with distributed generation into a separate rate class. The revenue requirements would be developed separately for this rate class, based on the characteristics of those customers.

4. THE COMPANY'S PROPOSAL WOULD HAVE A CHILLING EFFECT ON RESIDENTIAL SOLAR

Q. What effect would the Company's proposed Schedule 5 have on distributed solar in Utah?

A. Because net metering compensation is based on the energy rate, most new residential net metering customers would see much higher bills under Schedule 5 than they would under the standard residential rate design. In addition, Level 1 interconnection applicants would face an entirely new fee at the time of application, and Level 2 and Level 3 customers would see higher application fees. These impacts would be amplified by the phase-out of state tax credits, which will decline by $400 each year until they are eliminated at the end of 2021,[3] as well as the phase-out of federal tax credits.

Q. Have you quantified the impact on customer bills from the Company's proposed Schedule 5?

A. Yes. The impacts of the Company's rate design would vary based on an individual customer's load profile and solar generation. To conduct my analysis, I relied on NEM

[3] Utah State Legislature, House Bill 23, Income Tax Modifications, 2017 General Session, available at https://le.utah.gov/~2017/bills/static/HB0023.html

customer hourly load profiles, hourly generation profiles, annual export data, and billing determinants provided for a small sample of NEM customers provided by the Company through its load research study.[4]

After excluding customers with incomplete data or errors in their data, my sample contained 34 NEM customers. I then focused my analysis on the customers with average monthly site consumption[5] of less than 1,800 kWh. This final sample contained 26 NEM customers.

Q. Why is your sample size so small?

A. The Company's NEM load research study was based on a small sample of net metering customers. Only 34 customers had usable consumption and generation data.[6]

Q. Why did you limit your sample to customers with average monthly energy consumption of less than 1,800 kWh?

A. Compared with data for the population of residential NEM customers,[7] the Company's load research study sample is skewed toward large residential NEM customers. To make the sample more comparable to actual NEM customers' usage, I restricted the sample to customers with less than 1,800 kWh of monthly consumption.

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[4] Data provided in response to Confidential UCE 9.3-1.

[5] Site consumption is equal to the gross electricity consumption of the customer, regardless of whether the electricity is from the grid or from the solar array.

[6] One of the production meters recorded generation that was less than the amount of generation reported as exported to the grid, so this customer was omitted from the analysis.

[7] Based on analysis of R-135 NEM customers provided as Confidential Attachment EFCA 1.5-1. Data for 2015, limited to customers with 12 months of billing data

The table below shows how my sparse sample of NEM customers (excluding customers with site consumption of 1,800 kWh or above) compares with 2015 residential NEM customers (on the left) and the Company's load research study sample (middle column). The top portion of the table shows a comparison based on average monthly site consumption, while the bottom portion of the table is limited to deliveries from the grid.

As evidenced by the table, the sparse sample is a much more accurate reflection of actual NEM customers' characteristics. In contrast, the customers in the Company's load research sample consume much more electricity than actual 2015 NEM customers.

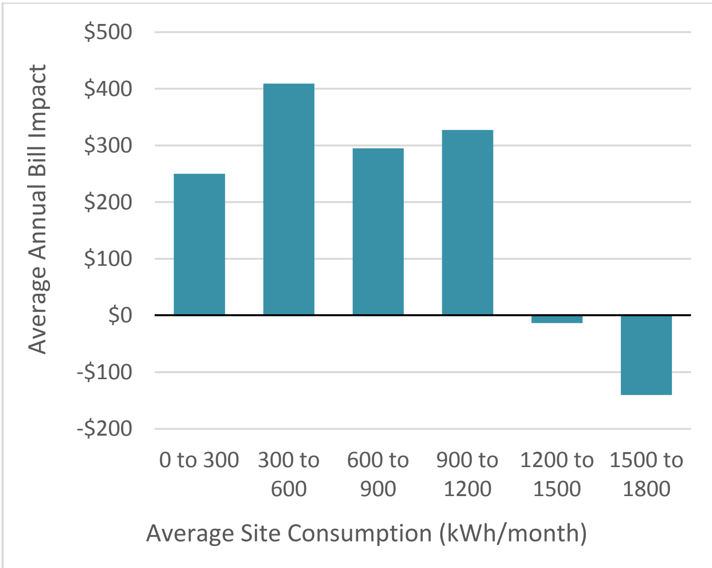
Table 3. Comparison of NEM Population to Load Research Sample to Sparse Sample

SITE CONSUMPTION			
	Actual 2015 R-135 Customers (kWh/month)	**Load Research Sample (kWh/month)**	**Sparse Sample (kWh/month)**
Average	969	1,660	934
Median	793	1,268	783
25th Percentile	530	674	576
75th Percentile	1,163	1,856	1,390
DELIVERIES			
	Actual 2015 R-135 Customers (kWh/month)	**Load Research Sample (kWh/month)**	**Sparse Sample (kWh/month)**
Average	738	1,343	743
Median	588	969	608
25th Percentile	407	423	390
75th Percentile	867	1,578	1,141

Q. What were the results of your analysis?

A. The results of my analysis show that most customers in the sample would see significant bill increases under the Company's proposed rate design relative to the current net metering rate. Customers with electricity usage below 1,200 kWh per month would experience much higher bills under the Company's proposed Schedule 5 than under current rates. Average annual bills for these customers would be $200 to $400 higher than they would be under current rates. These impacts are shown in the graph below.

Figure 1. Annual Bill Impacts Relative to Current Rates for Sample of NEM Customers



For some low- and moderate-usage customers,[8] installing solar would actually increase their electric bill above what it was *before* they installed solar.

Q. Would such bill impacts affect the ability of customers to adopt solar in Utah?

A. Absolutely. To put this in context, over the 25 year operating life of a solar photovoltaic system, an annual bill impact of $300 would translate to $7,500 of reduced savings.

Another way to analyze impacts is to study how customer payback periods would change under the proposed rates. Very short customer payback periods will likely lead to rapid adoption of distributed solar, while long customer payback periods will likely result in little adoption. In other words, changing a customer's payback period will impact how

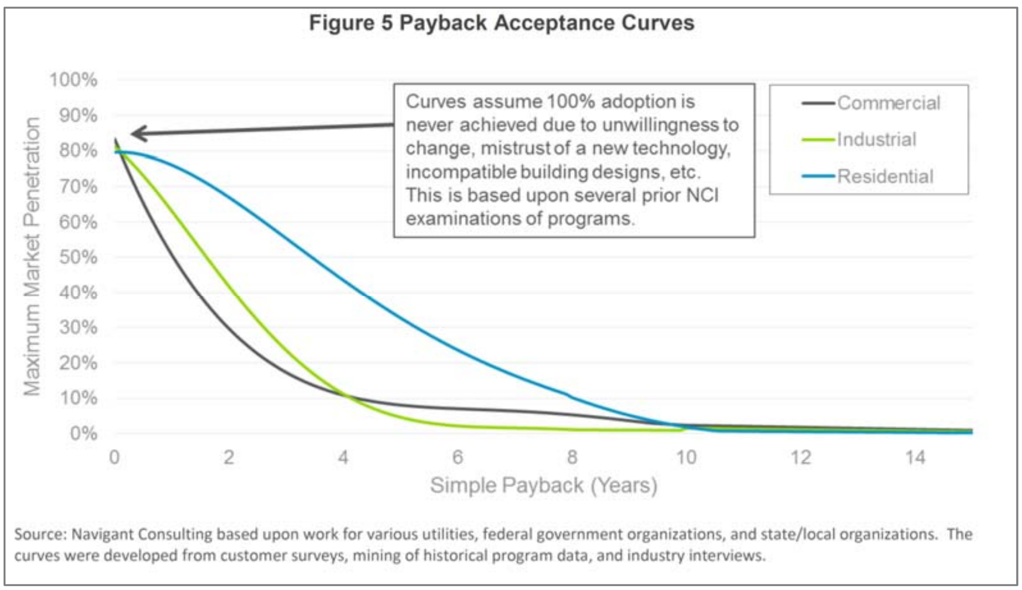
[8] Six of the 26 customers in my sample experienced bill increases relative to the bills they paid without solar.

economically attractive distributed solar is, and thereby affect how many customers ultimately adopt the technology.

Q. Have any studies been conducted to determine how distributed generation adoption would be affected by different payback periods?

A. Yes. In 2016, Navigant Consulting conducted an analysis for PacifiCorp of likely distributed generation penetration rates ultimately resulting from various payback periods. The results of their analysis are shown in the graph below:[9]

Figure 2. Navigant's Estimates of Payback Acceptance Curves Prepared for PacifiCorp



Q. What does Navigant's analysis demonstrate?

A. Navigant's analysis of distributed generation adoption shows that customer willingness to adopt distributed generation declines as the payback period lengthens. According to

[9] Karin Corfee, Shalom Goffri, and Andrea Romano. "Private Generation Long-Term Resource Assessment (2017-2036)," Prepared for Pacificorp (San Francisco: Navigant Consulting, Inc., December 22, 2016), page 3.

Navigant's analysis, a payback period of more than 10 years would generally result in very little distributed solar adoption.

Q. In Exhibit JRS_7, Ms. Steward conducted a bill impact analysis using a representative customer load profile. Did you analyze the payback period for that customer profile?

A. Yes. The load profile used by Ms. Steward represents a customer with average monthly energy usage of 996 kWh. I assumed that this customer installed a 5.68 kW solar system, which would generate an average of 660 kWh per month, based on the average system size in recent years. In addition, I assumed a system cost of $2.93/watt, which is slightly less than was assumed by Navigant in its *July 2016 Private Generation Long-Term Resource Assessment* for PacifiCorp. Finally, I assumed that no financing costs are incurred by the customer, and that the customer would be able to take full advantage of the Utah and federal tax credits. [10]

Q. What was the result of your analysis for the representative customer profile used by Ms. Steward?

A. Under the assumptions described above, the customer would see their payback period increase from approximately 13 years under current rates to 30 years under the Company's proposed rates.[11]

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[10] $2.93/watt purchase and installation cost based on NREL's U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016. Actual installed costs in Utah may be higher. Analysis also assumes $10/kW/year maintenance cost; $2,000 Utah state tax incentive; and 30% federal tax incentive.

[11] Analysis based on load profile and solar generation profile assumed in Workpaper JRS-7. Load profile results in consumption of 996 kWh. Solar generation was scaled to a 5.68 kW system size, based on the average size of 2012-2015 residential installations from Attach EFCA 1.24, resulting in an average of 660 kWh/month.

Q. What is the implication of lengthening the payback period for the representative customer to 30 years?

A payback period of 30 years would exceed the expected 25-year lifetime of standard solar PV arrays,[12] meaning that customers would never recoup their investment under the Company's proposed rate design. Few customers would be willing to install a solar array under such adverse economics. The Company's proposed rate design would have a chilling effect on the residential solar market in Utah.

Q. How would the Company's proposed Schedule 5 impact payback periods for residential customers in your sample of 26 customers?

A. For the customers in my sample, the payback period would lengthen considerably relative to current payback periods. Under the current rates, I estimate that only about 23 percent of the customers in my sample currently have a payback period of more than 15 years.

In contrast, under the new rates, approximately 54 percent of customers would see payback periods of more than 15 years. In fact, 42 percent of the customers in this sample would see payback periods of *more than 30 years*. It is unlikely that many customers would install solar with a payback period of more than 15 years, and certainly not more than 30 years.

[12] Photovoltaic performance declines over time. *See* Dirk Jordan et al., "Compendium of Photovoltaic Degradation Rates," *Progress in Photovoltaics* 24, no. 7 (July 2016): 978–89. Most residential solar panels come with a warranty of 25 years. See, for example, http://www.mitsubishielectricsolar.com/products/warranty/.

Q. Your assumptions include current state and federal tax credits. Do you expect these tax credits to remain over the long-term?

A. No. The payback example above assumes that the customer receives a Utah tax credit of $2,000 and the 30% federal tax credit. However, the Utah tax credit is due to phase out over the next few years. Starting in 2018 the credit will be reduced by $400 each year until it reaches zero in 2021. In addition, the federal tax credit will begin to step down in 2020, before being eliminated in 2022.[13]

Q. How will the reduced Utah tax credits affect the economics of distributed generation in Utah?

A. They will make the economics significantly worse. The current $2,000 tax credit represents a significant portion of the up-front costs of distributed generation facilities. Without the tax credit, the residential customer described above would see their payback period lengthened, which will reduce the growth of distributed generation in Utah. Figure 1 in Ms. Steward's direct testimony shows a substantial increase in residential NEM participation in recent years. This increase was driven in part by the Utah tax credits. Once those credits are reduced and eliminated, the economic value of NEM will be reduced, slowing the growth rate of distributed solar.

[13] The federal tax credit will decline to 26% in 2020 and 22% in 2021, before being eliminated in 2022. See: U.S. Department of Energy, "Residential Renewable Energy Tax Credit," *Energy.gov*, 2017, https://energy.gov/savings/residential-renewable-energy-tax-credit.

Q. Why is it important for the Commission to recognize the impact of the Utah tax credits in this docket?

A. The Commission should recognize that the combined effect of the reduced tax credits and the Company's proposed NEM rate design would make NEM facilities uneconomic for most residential customers in Utah. This would dramatically hinder the development of the distributed solar industry in Utah, and would deprive all electricity customers of the economic benefits of NEM facilities.

5. NET METERING REDUCES REVENUE REQUIREMENTS

Q. Did the Company analyze the costs and benefits associated with net metering?

A. As described in more detail by my colleague, Tim Woolf, the Company calculated the costs and benefits associated with net metering by comparing the revenue requirements under two cost of service studies:

- An actual cost of service (ACOS) study that includes net metering customers, and
- A counterfactual cost of service (CFCOS) study that includes all the same inputs and assumptions, except that it does not include any generation from net metering customers.

Q. What were the results of the Company's analysis?

A. A comparison of the revenue requirements under the CFCOS and the ACOS are presented in Table 3 below. As indicated, the ACOS case (including distributed generation) *reduces* revenue requirements for all classes by roughly $2.19 million, and *reduces* revenue requirements for the residential class by roughly $1.32 million. In other words, the Company's own cost of service analyses demonstrates that distributed generation results in *lower* costs to customers, not higher costs.

Table 4. Summary Results from CFCOS and ACOS

	CFCOS (excluding distributed generation)	ACOS (including distributed generation)	Difference (Savings due to DG)
Residential:			
Cost Per Customer	$1,000.53	$998.77	-$1.76
Total Class Revenue Req.	$754,461,852	$753,133,944	-$1,327,908
All Classes:			
Total Utah Revenue Req.	$1,926,352,189	$1,924,164,165	-$2,188,024

Q. What is the implication of the fact that distributed generation customers reduce revenue requirements for all customers?

A. The implication is that compensation for distributed generation customers should be set at a level that encourages an efficient level of adoption of cost-effective resources. If distributed generation compensation fails to account for the long-term benefits provided by distributed generation, then customers will not receive efficient price signals, will not invest in cost-effective resources, and all customers as a whole will incur higher electricity costs. This issue is addressed in more detail in the direct testimony of my colleague, Tim Woolf.

6. NEM CUSTOMERS SHOULD NOT BE IN A SEPARATE RATE CLASS

Q. Why is the Company proposing a separate rate class for NEM customers?

A. The Company claims that separating NEM customers will minimize the impact on other customers, and that the load characteristics of residential net metering customers are different from other residential customers.[14]

Q. Did the Commission require that NEM customers be segregated from non-NEM customers?

A. No. In fact, the Commission stated, "To be clear, the Commission is not here concluding that a new rate class should be instituted for net metering customers."[15]

Q. What analysis did the Company conduct regarding the different load characteristics of NEM customers?

A. Ms. Steward's Figure 2 purports to show that NEM customers' demand during the peak system hour (June 30, 2015) is not reduced relative to the average non-NEM residential customer. This figure is reproduced below.

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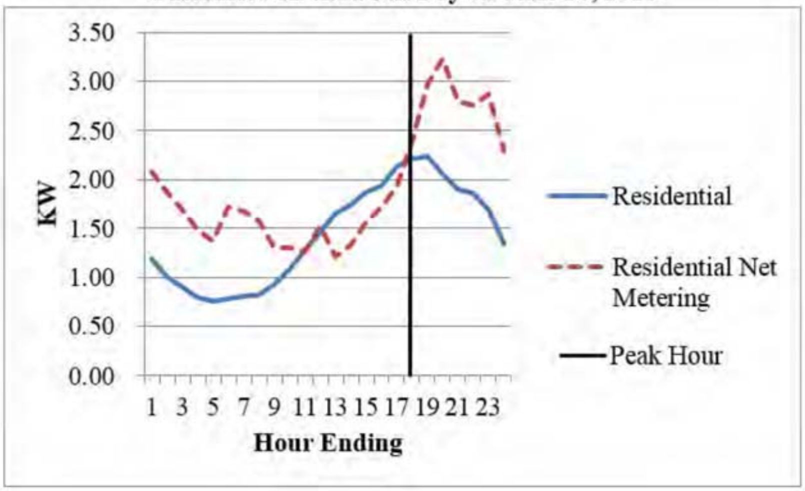
[14] Steward Direct, p. 16
[15] Nov. 2015 Order, p. 11.

Figure 3. Load Profile of Residential and Residential Net Metering Customers on the Peak Day on June 30, 2015



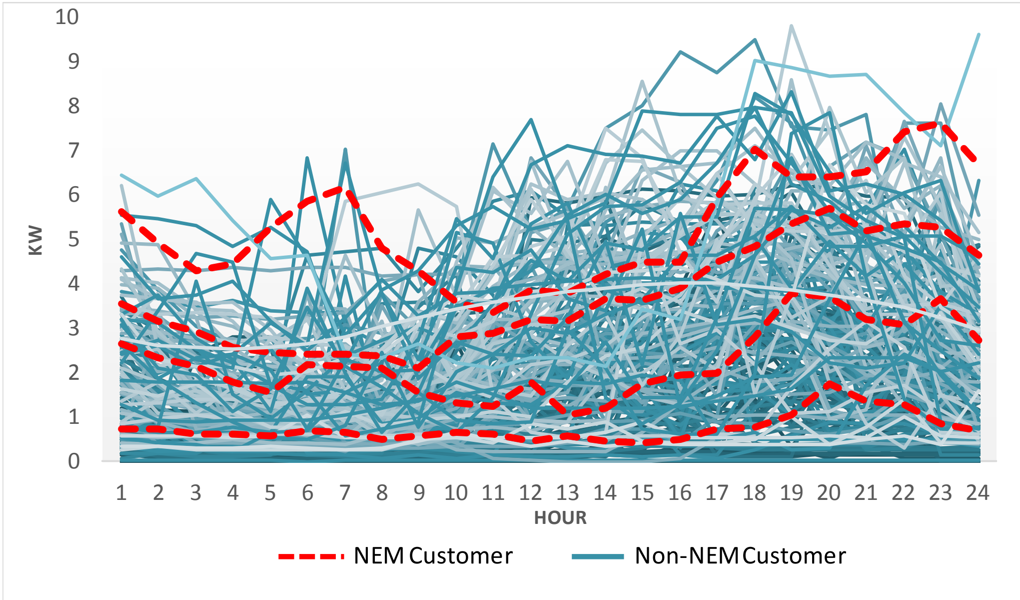
Q. Have you conducted any analysis to identify whether NEM customers have different usage characteristics than other residential customers?

A. Yes. I analyzed the range of non-NEM residential customer loads on the peak day and compared these loads to NEM customers, focusing on customers with peak load of 10 kW or less to exclude the small percentage of customers with very high usage characteristics.[16]

From a consumption standpoint, NEM customers are well within the range of other residential customers. The graph below shows four strata of NEM load profiles relative to non-NEM customer loads on the peak day:

[16] Data from Confidential Attachment EFCA 1.3 and Confidential Attachment EFCA 1.4.

Figure 3. NEM and Non-NEM Load Profiles on June 30, 2015



<u>A Separate Rate Class Would Increase Costs Allocated to Non-NEM Residential Customers</u>

Q. Please summarize the Company's findings from its NEM Breakout cost of service study for the residential class.

A. The Company states that the results "demonstrate that, as the net metering program is currently structured, the costs of the program exceed its benefits."[17] Further, the Company asserts that "the costs for the residential class would be reduced by $1.1 million if net metering customers were excluded from their class."[18]

[17] Meredith Direct, page 2
[18] Meredith Direct, page 26

Q. Do you agree with how the Company has presented the results of its NEM Breakout Cost of Service study?

A. No. The results of the Company's ACOS and NEM Breakout cost of service studies show that segregating NEM customers into a separate rate class would actually *increase* the cost allocated to non-NEM customers, on a per-customer basis.

Q. If creating a new rate class would *increase* costs allocated to non-NEM customers, why does Mr. Meredith state that "the costs for the residential class would be reduced by $1.1 million if net metering customers were excluded from their class"?[19]

Mr. Meredith's statement is misleading. Segregating NEM Customers into a separate rate class would reduce the number of customers in the residential class by 4,390 NEM customers. Removing these customers also removes the costs associated with those customers, thereby reducing the *total* costs allocated to the non-NEM residential class. On a *per-customer* basis, however, the costs to serve the non-NEM residential class are actually *higher* when NEM customers are separated out.

Q. Please summarize the costs to serve non-NEM residential customers on a per-customer basis across the three cost-of-service studies.

A. In terms of costs *per customer*, the cost to serve a non-NEM residential customer is highest under the CFCOS (which excludes NEM). The second-highest cost per non-NEM customer is in the NEM Breakout cost of service study, where the costs allocated to the

[19] Meredith Direct, page 26.

residential class do not include any of the costs to serve NEM customers. The cost to serve a non-NEM residential customer is lowest when non-NEM and NEM customers are in the same class. These results are summarized in the table below.

Table 5. Cost per Residential Customer across Cost of Service Studies

CFCOS	ACOS	ACOS – NEM Breakout
$1,000.53	$998.77	$999.45

The Company's results show that, on a per-customer basis, the costs to serve non-NEM customers increase by $0.68 when NEM customers are broken out into a separate rate class. While this is a relatively small number, the direction of this result is important; indicating that the costs to serve non-NEM customers increase when they are put in a separate rate class, likely due a reduction in class load diversity.

Q. What is the estimated cost to serve a residential NEM customer?

A. In the NEM Breakout ACOS, the Company estimates that the average cost to serve a residential NEM customer is $46 higher than the cost to serve a non-NEM customer.

Q. How does the Company's cost to serve a NEM customer compare to the benefits provided by NEM customers?

A. As shown in Table 4, the presence of NEM customers reduces RMP's costs by more than $2,000,000 for Utah as a whole, and by $1,327,908 for the residential class alone. There were 4,390 residential NEM customers in the Company's cost of service study. Dividing the $1,327,908 reduction in costs to the residential class by 4,390 residential NEM customers results in an average benefit of $302 per residential NEM customer. This benefit is significantly larger than the Company's estimate that residential NEM customers cost an average of $46 more to serve per year.

Q. Is segregating NEM customers into a separate rate class necessary to protect residential customers from cost-shifting?

A. No. As shown above, segregating NEM customers into a different rate class would actually increase the costs allocated to non-NEM residential customers. Further, if cost-shifting is a concern, it can be managed through adjusting compensation for excess generation, as I discuss below.

Q. Do you have any other concerns with creating a new rate class for NEM customers?

A. Yes. Creating a new rate class is not a practical or sustainable solution. If we segregate NEM customers because they have different load characteristics, would we create a separate rate class for customers with central air conditioning? With electric vehicles? With storage? With both storage and PV? Such end-use segregation is both impractical and inappropriate from a policy standpoint.

7. DEMAND CHARGES ARE NOT APPROPRIATE FOR RESIDENTIAL CUSTOMERS

Q. What accepted ratemaking principles should guide the designing of rates, as a general matter?

A. In the seminal work *Principles of Public Utility Rates* (1961), Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are as follows:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in the apportionment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

    (a) in the control of the total amounts of service supplied by the company;

    (b) in the control of the relative uses of alternative types of service.[20]

Q. Are these principles widely recognized and used by public utilities commissions?

A. Yes. The principles listed above have been recognized for many years across the nation.

Q. Is the Company's proposed residential NEM rate structure consistent with these rate design principles?

A. No. The Company's proposed Schedule 5 is inconsistent with the principles of efficiency, simplicity, and stability.

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[20] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press (1961), at 291.

Efficient Price Signals

Q. Please explain why a demand charge sends a less efficient price signal than alternative rate designs?

A. The demand charge concentrates the price signal into a single hour of the month – the hour of the customer's individual maximum demand. During the other peak hours, the price signal sent to customers to reduce demand is limited, since reducing demand below his or her monthly peak will have no financial benefit for the customer. Similarly, the price signal to reduce overall energy usage is reduced as implementing a demand charge reduces the energy usage charge significantly.[21]

In effect, a demand charge sends customers an inefficient price signal: that reducing electricity consumption outside of the customer's single peak hour is of less value to the system. A more efficient price signal would encourage customers to reduce energy consumption in each and every hour that the system is stressed, not just for the single hour that an individual customer reaches his or her maximum demand.

Q. The Company's proposal would only apply the demand charge during peak hours. Why would this not provide an efficient price signal?

A. Although limiting the demand charge to certain peak periods is better than applying the charge to all hours, it is still true that a customer's demand charge is only applied to one hour of the month. Thus, if the customer happens to have a spike in demand of 10 kW during a single hour, the customer has little incentive to reduce his or her demand below

[21] *See* Table 2, above.

10 kW for the rest of the billing period, since doing so would not affect the customer’s demand charge.

Q. Can you provide an example of how a demand charge fails to send an efficient price signal?

A. Yes. Suppose that Customer A hosted an event on July 3 that caused her to set a peak demand of 10 kW. Since Customer A’s typical demand is less than 5 kW, she has little incentive to minimize her demand for the rest of the month, since it is unlikely that she will exceed the 10 kW.

Now suppose that the actual system peak is reached on a hot summer day later that month. While it would be valuable to the system for Customer A to reduce her demand as much as possible, the demand charge does not reward her for doing so. Thus Customer A continues to run her central air conditioning at full force, while doing laundry and running the dishwasher, for a total demand of 9 kW during the system peak.

This simple example demonstrates how, by concentrating the demand charge on a customer’s single peak hour, a demand charge fails to provide an efficient price signal to reduce demand-related costs on the system during other peak hours.

Q. You noted that implementing a demand charge reduces the energy charge. Will reducing the energy charge impact customer incentives to invest in energy efficiency?

A. Yes. It is well-established that residential customers exhibit negative elasticity of demand. This means that, holding all else equal, a reduction in the price of electricity will lead to an increase in electricity consumption, and incentives for energy efficiency and conservation will be reduced. As discussed by the US Department of Energy, “Economic theory says that as energy prices rise, the quantity of energy demanded will fall, holding all other factors constant. Price elasticities are typically in the negative range, which indicates that demand falls as prices increase or, conversely, that demand increases as prices fall."[22]

When a demand charge is implemented, some of the costs that were previously recovered through the energy charge are moved to the demand charge, thereby lowering the volumetric price paid per kilowatt-hour. It follows that incentives for energy efficiency and conservation would therefore be reduced, unless this effect is offset by price signals embedded in the demand charge. As discussed elsewhere, however, the price signal sent by a demand charge is inefficient and much less transparent, and there is limited empirical evidence as to whether customers respond to demand charges.

Q. Why does a demand charge not provide an efficient price signal?

A. Demand charges have a fundamental flaw, even when designed to apply only during certain hours each day. First, the Company's proposed demand charge applies the same rate to demand that occurs during specific hours, regardless of the month. Yet peak system and distribution system demand occurs primarily during hot summer days, not mild afternoons in April.[23]

Second, the price signal to reduce demand is concentrated into a single hour of the month – the hour of the customer's individual maximum demand. During other hours, the price signal is limited, since reducing demand below the customer's monthly peak will

[22] M.A. Bernstein and J. Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," NREL Subcontract Report NREL/SR-620-39512 (National Renewable Energy Laboratory, February 2006), ix.

[23] Based on distribution system peak and coincident peak demand levels and hours in Attachment Vote Solar 1.12.

have no financial benefit for the customer. Thus, the price signal sent by the demand charge is that reducing electricity consumption outside of the customer's single peak hour is of little value to the system. A more efficient price signal would encourage customers to reduce energy consumption in each and every hour that the system is stressed, not just for the single hour that an individual customer reaches his or her maximum demand.

Finally, the demand charge reduces the energy rate ($/kWh), thereby reducing incentives for energy efficiency. As discussed above, a reduction in the price of electricity will lead to an increase in electricity consumption, and incentives for energy efficiency and conservation will be reduced.

Simplicity

Q. Does the Company's' proposed rate design comport with the principle of simplicity and understandability?

A. No. A key principle identified by Professor Bonbright is that rates should be designed with attributes of "simplicity, understandability, public acceptability and feasibility of application."

Demand charges represent a much more complex rate design than residential customers and many small commercial customers are accustomed to. Surveys and focus groups have found that the concept of demand charges are not well-understood and frequently raise concerns from customers.[24] Not only are demand charges conceptually

[24] Recent surveys indicate that approximately 50% of residential customers do not understand the terms "kW" and "kWh". *See:* LeBlanc, Bill. "Do Customers Understand Their Power Bill? Do They Care? What Utilities Need to

new, customers generally lack the tools needed to manage their demand. Without investing in automating technology, residential customers have little ability to monitor and quickly adjust their demand levels.[25] Further, where residential demand charges have been implemented, enrollment tends to be very low, indicating low levels of customer acceptance.

Q. What percentage of customers have enrolled in demand-based rates?

A. Of the 24 other examples of demand charges that have been applied to residential customers in the United States on an opt-in basis, most have enrollment below 1%,[26] despite existing for multiple years and customer marketing efforts.[27] The exceptions are Arizona Public Service (APS) with enrollment of 11% and Black Hills Power with enrollment of 8%.[28] Yet even at APS, customers prefer the energy-only time-of-use rate

Know." Blog summary of E Source Survey. January 21, 2016. https://www.esource.com/email/ENEWS/2016/Billing

Further, focus groups in Ontario found that the concept of maximum use during peak hours "is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU." Customers also expressed concerns regarding fairness, specifically that "that small lapses in their conservation efforts will mean they will have to pay a high price". *See:* Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups Final Report, October 9, 2013("Gandalf Report"), available at : http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0410/Appendix%20B%20-%20Gandalf%20Distribution%20Focus%20Groups.pdf at p. 9.

[25] For example, a widely held concern of participants in focus groups in Ontario regarding demand charges is that they do not have the tools to manage their demand. *See:* Gandalf Report, at pp. 6, 11.

[26] Rocky Mountain Institute, *A Review of Alternative Rate Designs*, May 2016 ("RMI Review"), at p. 72.

[27] For example, Alabama Power Co. has enrollment levels far below 1%, despite marketing efforts and having had the program in place for more than four years.

[28] RMI Review, *supra note 34*, at p. 72.

to the demand charge rate by a margin of four to one,[29] and each year approximately 20% to 25% of customers on the demand charge rate opt to leave the rate.[30]

Q. Have any investor-owned utilities made demand-based rates mandatory for residential customers?

A. Generally not. In fact, demand charges have been routinely rejected for mandatory application to residential customers. Several recent examples include California, Arizona, Nevada, and Oklahoma.

In California, the Commission explicitly rejected demand charges as a component of a net metering successor tariff. The Commission's rationale was that "demand charges can be complex and hard for residential customers to understand. Since the vast majority of NEM customers are residential customers, it is reasonable to consider the NEM successor tariff in light of the needs of residential customers. From that perspective, the NEM successor tariff should not incorporate a demand charge…"[31]

In Oklahoma, the Commission rejected the proposed demand charge and implemented two requirements that the utility must fulfill if it wishes to propose a demand charge in the future:

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[29] Eddie Easterling, "EUCI Residential Demand Charge Summit," May 14, 2015.

[30] Direct Testimony of James A. Heidell, on behalf of EFCA, Docket No. E-0I345A-16-0036 & E-01345A-I6-0123, February 3, 2017, pages 41-42.

[31] California Public Utilities Commission, Decision 16-01-044, Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking 14-07-002, January 28, 2016, p. 75.

1) The utility must first conduct a study and pilot program on demand charges to evaluate customer acceptance, understanding, and ability to respond to a demand charge; and

2) For any demand charge for customers with distributed generation, the utility must "include as part of its case cost effectiveness tests, such as those performed for the company's demand programs, and make available to the parties detailed cost and benefit data."[32]

In Arizona, the Commission recognized that there was significant "public distrust or antipathy to the [demand charge] proposal" and stated that "In order for customers to understand how demand charges work and how they can manage their energy consumption to save money, or at least not incur a bill increase, requires education and tools available to monitor their load," which have not "been made available."[33] Nevada's rationale for declining to implement a mandatory demand charge for net metered customers, similarly hinged on customer education needs and uncertainty regarding customer acceptance.[34]

[32] Oklahoma Corporation Commission, Final Order, Cause No. PUD 201500273, March 20, 2017, page 13.

[33] Arizona Corporation Commission, Decision No. 75697, Docket No. E-04204A-15-0142, August 8, 2016, at 65.

[34] Nevada Public Utilities Commission, Docket No. 15-07041 and Docket No. 15-07042, February 12, 2016, p. 147.

Continuity

Q. Is the Company's rate design consistent with the principle of rate stability (i.e., gradualism)?

A. No. Professor Bonbright defines this goal as the "stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[35] In contrast to a gradual approach, the Company's proposal would significantly alter the rate structure for residential net metered customers, who have never been on a demand charge before. In addition to introducing an entirely new charge in the form of a demand charge, the rate structure would more than double the fixed charge for many customers compared with current rates.

Rate Design Conclusions

Q. Please summarize your conclusions regarding the Company's proposed Schedule 5 rate design.

A. The proposed rate design is in direct contravention to the widely-accepted rate design principles. The proposed demand charge will fail to achieve the goals of efficiency and fairness, and in fact would reduce customer control, distort price signals, and lead to significant customer confusion. Further, the proposal would eliminate financial incentives for customers to install additional solar, thereby decimating the distributed solar industry in Utah. In addition, the mandatory demand charge for residential customers would create

[35] James Bonbright (1961) *Principles of Public Utility Rates*, Columbia University Press, page 291.

a dangerous precedent, and would certainly lead to future proposals aimed at expanding the breadth and magnitude of residential demand charges beyond solar customers.

For all of these reasons, the Company's proposal cannot be considered "just and reasonable," as required by the statute.

8. PRINCIPLES AND OPTIONS FOR DISTRIBUTED GENERATION COMPENSATION

Q. Do you recommend any general principles that should be used when determining compensation levels and rate designs for customers with distributed generation?

A. Yes. I offer the following recommendations:

1. Demand charges should not be implemented for any residential customers, including customers with distributed generation. Residential customers who have installed solar have no better ability to understand and manage their hourly maximum demand than standard residential customers. Moreover, as discussed above, demand charges do not provide an efficient price signal.

2. Any modification to distributed generation compensation should strike the right balance between supporting customers' ability to install distributed generation and mitigating against cost-shifting.

3. The compensation level should also recognize the benefits provided by distributed solar customers, which the Company estimates to be $1.3 million per year, which is roughly $300 annually per residential NEM customer.

4. Rate designs should be revisited and modified on a periodic basis in order to take into account changes in costs and benefits, as well as assess cost-shifting impacts on non-NEM customers.

Q. What recommendations do you have regarding modifications to the NEM program at this time?

A. I offer the following recommendations regarding modifying compensation for customers with distributed generation:

- If it the Commission determines that compensation for net metering customers should be reduced in order to mitigate cost shifting, I recommend simply reducing compensation for excess generation. This option is simple to implement, does not require special meters, does not distort price signals, and will encourage customers to not overbuild their distributed generation systems.
- Alternatively, I recommend that the Commission consider moving toward more efficient price signals in general, such as time-of-use pricing. This would provide more accurate hourly compensation for solar generation, and more accurate prices for hourly consumption. Peak and off-peak time periods can be adjusted in the future if the peak window shifts.

Q. How do you recommend that compensation for excess generation be determined?

A. I recommend that compensation for excess generation be set at a level that reflects the long-term value of distributed generation, which includes the benefits associated with the ability of distributed generation to defer or avoid large capital projects.

Q. Should the compensation for excess generation be stepped down over time from the current rate?

A. Stepping down compensation for excess generation from the current rate over time would be a reasonable approach, as doing so would allow changes to be phased in gradually, and would also allow compensation to be modified in response to changing solar penetration levels. For example, it might make sense to reduce compensation for excess generation by 5% for each 1% increase in NEM penetration (defined either as the percent of NEM customers relative to all customers, or in terms of capacity.)

Q. Should consumption and generation be netted on a monthly basis or an hourly basis?

A. Changing from netting on a monthly basis to netting on an hourly basis could result in dramatic changes to customer bills, and could undermine the economics of solar in a similar manner to the Company's proposed Schedule 5. As I noted above, any modification to distributed generation compensation should strike a balance between supporting distributed generation and mitigating against cost-shifting. For this reason, I recommend that netting continue on a monthly basis, at least until the impacts of hourly netting are better understood.

Q. Would hourly netting impact customers' willingness to install distributed generation?

A. Yes. Under hourly netting, the economics of installing a solar array could vary dramatically depending on a customer's hourly load profile. However, residential customers in Utah do not generally have access to their hourly load profiles, and thus it would be very difficult for a customer to evaluate the economics of installing solar under an hourly netting regime. This uncertainty regarding bill savings would likely significantly reduce customer willingness to make a large investment in distributed generation.

Q. Do you recommend that any change to net metering compensation be made at this time?

A. If the Commission determines that it is appropriate to modify compensation for excess generation, a modest change could be made at this time. However, significant changes to rate design should not be implemented until a future rate case.

Q. Does this conclude your direct testimony?

A. Yes, it does.