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** **DPU Exhibit 2.0 DIR-COS**

COST OF SERVICE

(NET METERING PROGRAM)

DIRECT TESTIMONY OF STAN FARYNIARZ

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

June 8, 2017

I. INTRODUCTION

Q. What is your name and business address?

A. My name is Stan Faryniarz. I work for Daymark Energy Advisors ("Daymark"), headquartered at One Washington Mall, 9th Floor, Boston, MA 02108.

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

A. I am testifying on behalf of the Utah Division of Public Utilities ("Division" or "DPU").

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

A. Yes, in Docket 13-035-184, which addressed Rocky Mountain Power's general rate case and rate design issues, RMP's net energy metering ("NEM") program, and its proposed facilities charge for NEM customers.

Q. Please describe your background and experience.

A. I am a Principal Consultant at Daymark. I am an energy economist and power supply planning and management specialist with 31 years of experience in areas including electric utility cost of service and rates, power supply procurement and management, wholesale and retail power transactions, power project financial analysis and due diligence, asset and utility valuations, and integrated resource planning and analysis.

I have advised managers concerning the electric power supplies of public and investor-owned electric utilities, and have advised large industrial customers, regulators, consumer advocates, and power plant developers and owners regarding specific power projects and transactions, portfolio risk management strategies, and power markets.

I have prepared numerous valuation analyses of power projects and assets, combined portfolios of assets, and electric utilities. This work has involved power production assets in the northeastern U.S., North Carolina, Ohio, Arkansas, Wisconsin, and Canada. I have evaluated the economics, contract structure, ratepayer security, development prospects or going-forward value of dozens of renewable, non-renewable merchant, and Qualifying Facility ("QF") power projects in the northeastern U.S. and Canada. I have conducted this work for regulators and for providers of private capital and quasi-public capital.

I have prepared, or have overseen the preparation of all or portions of integrated resource plans for several Vermont utilities and for other public utilities, and I am a load forecasting specialist.

My experience includes the preparation of well over a dozen electric and water utility allocated cost of service and rate design studies, rate unbundling studies, and rate path projection studies, for or involving utilities in the northeastern U.S., North Carolina, and New Hampshire.

My experience and qualifications are described in more detail in my resume and selected testimony appendix, which are attached as DPU Exhibit 2.1 DIR-COS.

Q. Please describe your educational background.

A. I have a bachelor's degree with honors in Economics, and a Master's degree in Public Administration (finance and managerial economics concentration) from the University of Vermont. I have completed additional post-graduate coursework in Regulatory Economics, and I hold the Certified Energy Procurement (CEP) Professional credential from the Association of Energy Engineers.

Q. What is the purpose of your testimony?

A. I have been retained by the Division to review and analyze the cost of service studies, load research study, distribution level costs and benefits of distributed generation ("DG"), and other aspects of the net metering program that were presented by Rocky Mountain Power ("RMP", "PacifiCorp", or "the Company") in its Compliance Filing.

Q. What material did you review before you prepared your testimony?

A. I began with an analysis of the Company's NEM rate design proposal, as outlined in testimony provided by RMP. I reviewed direct testimony, which included the Company's NEM rate design proposal provided by the Company's five witnesses, and various data requests and responses in this docket. I have also reviewed certain materials associated with other Public Service Commission of Utah ("Commission") proceedings that are relevant to this one.

Q. What areas will your testimony address?

A. I will address the following:

- The reasonableness of the Company's Actual Cost of Service ("ACOS"), Counterfactual Cost of Service ("CFCOS"), and Net Energy Metering Breakout Cost of Service ("NEM Breakout COS") studies.
- The results of RMP's load research study.
- A review of the Company's proposed distribution level costs and benefits associated with distributed generation on its system.
- The appropriateness of the Company's proposal to separate NEM customers into their own class.
- The appropriateness of the Company's proposed Schedule 5 rate design, which includes demand charges and an increased customer charge, and related public policy issues.
- The current compensation for excess generation from residential customers.
- The Company's proposal to eliminate the option to receive excess generation compensation at the average retail rate for non-residential customers.
- The Company's proposal to implement new application fees for all levels of requests for interconnection.
- Other miscellaneous issues.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations include:

- Based on my analysis and findings described below, it is not necessary, for now and at the current level of penetration, to separate NEM customers into their own class. Despite this, I do not object to the separation of NEM customers into a separate class if deemed appropriate for other policy reasons, or to address compensation rates for excess generation exported to the grid.
- My conclusions regarding the importance of correctly valuing exports, NEM costs and benefits, and the use of application fees and interconnection fees apply to both residential and commercial NEM customers.
- Compensation for energy exports at retail rates is the primary driver of the low revenue parity ratio for residential NEM customers shown in the Company's NEM Breakout ACOS study.
- Traditional NEM excess energy compensation, at full retail rates, is not sustainable in the long-run with very high rates of DG penetration.
- Since the Company is using a one-year historic test-period for its cost-benefit analyses as discussed from the Phase I Commission Order, it is likely that transmission, distribution, and environmental compliance avoided cost benefits may not be able to be properly captured. Evidence of such benefits might be presented by other parties in this docket and I will respond subsequently as appropriate.

- I would recommend that the Commission consider opening a separate docket to properly vet possible DG costs and benefits to RMP's distribution system, which potentially could include parties to the current docket and all stakeholders with an interest in DG, in order to determine the export compensation rate.
- I agree with the Company that there is a cost of interconnection incurred for both program administration and engineering review when a customer submits an interconnection application for any DG system, regardless of size. These costs should be borne only by the applicants since non-NEM customers are not contributing to these costs. In addition, I recommend that interconnection costs vary based on whether the interconnecting DG system is expected to export power to the grid.
- I recommend the Company clarify how the need to meter bidirectional flows would impact average per meter costs to serve Schedule 23 NEM customers compared to non-NEM customers.
- I do not recommend that transformer costs be included in the customer charge for residential customers. Although these costs may be fixed, that does not by itself justify their inclusion in the customer charge. In addition, any transformer upgrades needed are best recovered through an interconnection charge and not a monthly customer charge.
- I recommend the Company ensure that the transformer allocator does not double count customers in its NCP calculation. This should reduce costs allocated to the NEM residential class for the NEM breakout ACOS study.

- Regardless of the ultimate rate design and rates approved by the Commission, the rate design and rates should be gradually implemented through steps that enable proper transition to bi-directional meters and avoid or mitigate adverse average rate and bill impacts for customers.
- Data collection through a rate pilot program(s) could enable the Commission to make more informed decisions about different time-based rate structures going forward.
- By decreasing the NEM program cap to a level near the current program size or a near-term projection of size, the Commission can create a defensible class of NEM customers that might be gradually transitioned while newcomers after the Commission's order in this proceeding might have a new regime immediately applied.

II. BACKGROUND

<u>A. Net Metering History</u>

Q. Please briefly describe Utah's Net Metering Statute history.

A. In 2002, the Net Metering Statute (Utah Code Ann. § 54-15-101 et seq.) was enacted. On May 13, 2014, a revision to the Net Metering Statute, addressing the determination of cost and benefits, became effective. Utah Code Ann. § 54-15-105.1 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.

For the remainder of my testimony, I will refer to Utah Code Ann. § 54-15-105.1(1) as Subsection One and Utah Code Ann. § 54-15-105.1(2) as Subsection Two.

Q. What other legislation is impacting net metering in Utah?

A. In addition to the Net Metering Statute, on March 25, 2014, the Legislature signed Senate Bill 208 into law, which required the Commission to "convene a process to evaluate the costs and benefits of net metering, and to determine a "just and reasonable" rate structure considering those costs and benefits"[1]. The Commission initially opened this docket back on August 29, 2014 to review RMP's net metering program costs and benefits, as required by Subsection One.

Q. What did the Commission order in the docket?

A. On November 10, 2015, the Commission ordered RMP to make a Compliance Filing[2] that consists of two COS studies (ACOS and CFCOS) covering the test period used in RMP's next general rate case. These COS studies would serve as a framework to assess the costs and benefits of net metering by comparing a COS study without net metering customers to a COS study with net metering customers. The Commission order specifically stated[3]:

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[1] http://programs.dsireusa.org/system/program/detail/743.

[2] I use the term Compliance Filing here as a label for what the Commission required in its order, not in reference to the Company's filing, which it also termed a "Compliance Filing", and which differs from the Commission's order in certain respects. Despite the difference, I will refer to the Company's filing as its Compliance Filing for convenience.

[3] Docket No. 14-035-114 Order, November 10, 2015, p. 16.

> 1. Two cost of service studies as described in this order. In one cost of service study (the "CFCOS"), PacifiCorp will use its best efforts to estimate what its cost of service would be if net metering customers produced no electricity, drawing their entire load from PacifiCorp and providing no surplus energy to the system. The second cost of service study (the "ACOS") should reflect PacifiCorp's actual cost of service with net metering customers' participation, meaning PacifiCorp provides net metering customers with energy only when their self-generation is insufficient to meet their load and net metering customers push any surplus energy they produce to the system.
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> 2. Both the CFCOS and ACOS will reflect costs at the system, state and customer class level.
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> 3. The ACOS will illustrate cost of service in two respects at the customer class level. First, the ACOS will reflect class cost of service with net metering customers included in their existing class. Second, the ACOS will segregate net metering customers from the class in which they presently participate and reflect the resulting class cost of service to the net metering customers as a separate class and show the impact their segregation has on the class in which they would otherwise participate.
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> 4. The period of time covered by each of the cost of service studies shall be commensurate with the test period in PacifiCorp's next general rate case.

B. RMP's Compliance Filing

Q. Please briefly explain the COS studies the Company provided as part of its Compliance Filing.

A. After the Commission's order, the Company filed an ACOS study and a CFCOS study that compared the costs of service at the system, state, and customer class levels. For both COS studies, the Company used a one-year test period, which ended December 31, 2015, and modeled the costs to serve customers in its jurisdictional allocation model ("JAM"). The COS studies were supported by a load research study, which compiled a year's worth of data for all customers, including data for residential NEM customers, but not NEM customers on Schedules 6, 10, and 23.[4]

In addition to the ACOS and CFCOS, the Commission required the Company to complete a NEM Breakout COS, which placed net energy metering ("NEM") customers into a separate class to show how their removal affected the class they otherwise belonged under. The NEM Breakout COS was created by taking the ACOS study and separating out NEM customers from each of the classes (residential, Schedule 23, Schedule 6, Schedule 8, and Schedule 10) based on their cost of service characteristics.

Q. What are the differences between the ACOS and CFCOS studies?

A. The main difference between the two COS studies was that the CFCOS study relied on the Company's estimation of the cost of serving the current NEM customers if they were completely reliant on RMP for all their electricity needs, meaning they do not generate any of their own requirements, nor do they export surplus energy to the system. By assuming the NEM program no longer existed, the Company made the following assumptions in its counterfactual JAM ("CFJAM"): higher net power costs ("NPC") to supply energy[5] and to account for line losses for remote energy delivery; removing bill credits from private generation; lower costs for metering, customer service, billing, and engineering and administrative interconnection costs; and allocating more system costs to

[4] Direct Testimony of Robert M. Meredith, p. 25, lines 520-522.
[5] To make up for energy not generated by NEM customers.

Utah because of increased energy demands in the state.[6] The CFJAM is used in the CFCOS, which includes higher revenues, energy, and demands for classes that include NEM customers.[7] In addition to these changes, the Company applied a $2.0 million rate decrease to the CFCOS results (difference between the CFJAM and ACOS JAM) to hold the rate of return constant between the two COS studies.[8]

Q. What assumptions did the Company make in the CFCOS regarding increased energy consumption due to assumed lack of private distributed generation?

A. The Company's ACOS uses the known amount of net energy usage and net revenue associated with that usage that it bills to NEM customers. The Company's CFCOS provides an estimate of the DG production to determine full requirements usage. DG production is "estimated by multiplying a standardized production profile by the nameplate capacity of each customer's generation system on a monthly basis".[9] Then full requirements usage can be determined by adding the estimated DG production less the energy exported from the NEM customer to the grid plus the energy delivered to the NEM customer from the grid.[10] This is done for each class to get the total full requirements energy for all NEM customers on the system.

[6] Direct Testimony of Robert M. Meredith, pp. 4-5, lines 83-95.
[7] *Id.*, p. 5, lines 99-100.
[8] *Id.*, p. 5, lines 103-106.
[9] *Id.*, p. 9, lines 176-178.
[10] The energy flowing from the NEM customer to the grid and vice versa is measured using a bi-directional meter.

The standardized production profile used to estimate DG production was generated from data gathered from 36 production profile meters capable of capturing 15-minute interval data from willing residential customer participants in the Company's load research study.[11] Specifically, the Company created generic shapes for all DG systems using the production profile data collected by assigning the value of 1.0 to the highest 15-minute reading and then dividing all other values by that reading. The overall standardized production profile is the average of all the generic production shapes for the state, weighted by the generic profiles of each county by total nameplate capacity installed in each county through the end of 2015. The Company benchmarked its standardized production profile against hourly shapes from the National Renewable Energy Laboratory ("NREL") online PVWatts® calculator and found that they were similar.

Q. Based on the energy sales assumptions the Company made in the CFCOS, how do the energy sales in the CFCOS compare to the ACOS?

A. The energy sales in the CFCOS are estimated to be 239,706 MWh, which is 51,297 MWh more than the actual 2015 energy sales of 188,410 MWh.[12] This difference is 1,580 MWh less than the Company's estimated DG production of 52,877 MWh[13] and is explained to be caused by NEM banking[14], which is reflected in the ACOS, but not the CFCOS.

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[11] Direct Testimony of Robert M. Meredith, p. 10, lines 183-186.
[12] *Id.*, p. 12, lines 227-230.
[13] *Id.*, p. 12, lines 234-235.
[14] Crediting of kWh from a current bill to a future bill due to delivering more energy to the grid than consuming from the grid in the current billing period.

Q. What assumptions did the Company make in the CFCOS regarding increased demand due to assumed lack of private distributed generation?

A. At the input level, the Company modified Utah state border loads and allocation factors, accounting for line losses, to adjust for the change in DG production that previously reduced Utah's jurisdictional allocation.[15] To be consistent with how loads were developed in the CFJAM, customer class loads in the CFCOS were expanded by the total DG production profile. In addition, the Company accounted for line losses by first bringing DG production to the input level. This involved determining the monthly installed capacity for customers served at both the primary and secondary voltage levels. Then DG production was expanded by class by loss factor.[16] So, with line losses now incorporated, DG production at the input level increased by 4,907 MWh from the estimated 52,877 MWh, reflecting 8% line losses.

Q. What assumptions did the Company make in the CFCOS regarding bill credits?

A. RMP removed bill credits[17] from the CFCOS by putting the energy differences between the full requirements and actual billed energy into summer and winter blocks, and when possible, peak and off-peak periods, and multiplying the energy blocks by the revenue differences.[18] Because residential customers have tiered block usage levels, the Company had to first estimate the full requirements energy for each monthly bill to determine levels

[15] Direct Testimony of Robert M. Meredith, pp. 13-14, lines 255-262.
[16] See 2015 cost of service study for loss factors used based on quantities of nameplate capacity.
[17] See Exhibit RMP_(RMM-5) for bill credits by rate schedule.
[18] Direct Testimony of Robert M. Meredith, p. 14, lines 277-281.

of energy consumption. Then the proportional changes in energy by tier were applied to total estimated energy change to estimate the residential class' bill credits.[19]

Q. What assumptions did the Company make in the CFCOS regarding customer service and billing costs for NEM customers?

A. Costs[20] for customer service and billing attributable to NEM customers were developed by multiplying call center agent fully-loaded hourly costs by time estimates from Company personnel involved in phone calls related to the NEM program, initial setup of customers on the NEM program (including exchange of meters and billing system setup), and ongoing support for NEM customers once they enroll in the program (including billing back office support).[21] To determine cost allocation by class for the period, each activity's total costs were allocated based on cost drivers, i.e. phone calls were allocated to application numbers, initial setup was allocated to interconnection requests, and ongoing support was allocated to average bill numbers.[22]

Q. What assumptions did the Company make in the CFCOS regarding NEM program administration?

A. Since PacifiCorp has a NEM program administration department that processes interconnection applications in six states, it allocated program administration costs[23] to

[19] *Id.*, p. 15, lines 282-287.
[20] See Exhibit RMP_(RMM-6) for customer service and billing costs by class.
[21] Direct Testimony of Robert M. Meredith, pp. 15-16, lines 295-306.
[22] *Id.*, p. 16, lines 307-315.
[23] See Exhibit RMP_(RMM-7) for administrative expenses by class, state and rate schedule.

Utah based on the state's proportional workload, which was further reduced by application fees the Company collected from larger commercial interconnections.[24]

Q. What assumptions did the Company make in the CFCOS regarding engineering costs related to the NEM program?

A. Similar to the customer service and billing cost allocation, the Company estimated application review time and then multiplied it by a field engineer's fully-loaded hourly cost and then by the total number of 2015 applications.[25] Engineering expenses for the different rate schedules vary based on application complexity[26], which the Company asserts leads to longer review time.

Q. What assumptions did the Company make in the CFCOS regarding metering costs related to the NEM program?

A. Under the current NEM program, billing requires measuring the bi-directional energy flow. Therefore, metering costs were estimated by the Company based on replacement and reprograming of current meters.[27]

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

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[24] Direct Testimony of Robert M. Meredith, p. 16, lines 318-324.
[25] *Id.*, p. 17, lines 330-335.
[26] See Exhibit RMP_(RMM-8) for engineering expenses by customer class.
[27] See Exhibit RMP_(RMM-9) for metering costs by customer class and calculations showing meter depreciation and deferred tax impacts.

A. Per the Company's analysis, the net metering program produced a *net cost* at the system, state, and class levels. Specifically, the Company found that the net cost of the net metering program was $3.7 million (about $70.40/MWh)[28] to the system, $2.0 million (about $38.76/MWh) to the state, and $1.7 million (about $58.60/MWh) for the residential class.[29] The Company provided the summary table shown below[30], which shows the net cost of the net metering program at all levels, including a class level impact.

Table 1 – Net Cost/(Benefit) of the Net Metering Program at the System, State, and Customer Class Levels.

	Cost (000)	Benefit (000)	Net Cost/ (Benefit) (000)
System Level	$ 5,010	$ (1,287)	$ 3,722
State Level	$ 5,010	$ (2,960)	$ 2,049
Residential	$ 3,540	$ (1,881)	$ 1,659
Schedule 23	$ 504	$ (405)	$ 100
Schedule 6	$ 673	$ (650)	$ 23
Schedule 8	$ 240	$ (395)	$ (155)
Schedule 10	$ 29	$ (21)	$ 7
Other Classes	$ 22	$ 393	$ 415
Total Customer Class Level	$ 5,009	$ (2,960)	$ 2,049

Q. What other cost of service analysis did the Company perform in compliance with the November 2015 Commission Order?

[28] MWh is defined as megawatt hour.
[29] Direct Testimony of Robert M. Meredith, p. 6, lines 116-118, 122-123, and 127-129.
[30] *Id.*, p. 7, line 135

A. As I discussed earlier, the Company completed a NEM Breakout COS study to show the cost to serve NEM customers from the ACOS if they were put into a separate class. The costs to serve NEM customers are based on their characteristics, which include "different customer counts, revenues, energy values, system coincident peak demand values, distribution coincident peak demand values, non-coincident peak demand values, number of customers per transformer, and metering costs."[31]

Q. Based on the different characteristics of NEM customers, how did the Company develop demand values for NEM customers?

A. When the Company conducted its load research study, it gathered 15-minute interval data measuring delivered and exported energy for 36 residential NEM customers for 2015.[32] The Company developed loads for the NEM Breakout COS by using "delivered energy to inform strata weightings and breakpoints, because delivered energy is an indication of the customer's usage of the system, as opposed to net energy that is a billing-related construct".[33]

NEM customer profiles were scaled to monthly energy volumes, which allowed the Company to develop monthly system and distribution coincident peaks based on energy deliveries to the customer. Further, the Company averaged the non-coincident peaks for each of the NEM sample customers and then scaled this value based on the total number

[31] *Id.*, p. 19, lines 376-379.
[32] However, the Company used data from 52 meters to develop loads for the NEM Breakout COS. Direct Testimony of Robert M. Meredith, p. 21, lines 418-420.
[33] Direct Testimony of Robert M. Meredith, p. 21, lines 427-430.

of customers to create a non-coincident monthly peak, which was based on the maximum of energy delivered or exported.[34]

The Company does not have separate data for NEM customers in Schedules 23, 6, and 10. So, full requirements profiles were created by adjusting the standard profile for each class from the ACOS study "to the overall energy volume for estimated full requirements usage of net metering customers on a monthly basis".[35] Then the Company estimated hourly delivered and exported energy by overlaying estimated DG production profiles for each class. The Company noted that Schedule 8 customer demand values are determined from profile meter readings for all customers.

Q. Did the Company include any other differences in its NEM Breakout COS study?

A. Yes. The Company assigned engineering, administration, customer service, and billing costs that it claimed were attributable to NEM customers due to the interconnection process and service needs of the NEM customers.[36] In addition, NEM customers can be allocated energy costs the Company incurs to serve them, i.e. based on their usage of the system, and can be credited for the excess generation they provide. This credit is assigned to NEM customers "based upon differences in monthly net power costs associated with private generation that was calculated for the CFCOS analysis".[37] In addition, the Company captures avoided line losses by increasing the credits that it applies to excess

[34] *Id.*, p. 19, lines 387-390.
[35] *Id.*, p. 20, lines 402-404.
[36] *Id.*, p. 21, lines 434-436.
[37] *Id.*, p. 23, lines 465-466.

generation delivered to the system. For the NEM Breakout COS, the Company also considered the impact of banking because the cost of service study used billed energy revenues from NEM customers that were impacted by banking outside of the test year. The Company explains that "[s]ubtracting the excess energy, which includes both the energy exported as well as the impact of banking, from the delivered energy, produces the billed energy upon which revenues are determined and upon which the total energy in the ACOS is based."[38] By including impacts of banking, the Company claims it is ensuring there is not a mismatch created between revenues and cost of service.

Q. How does the Company allocate excess energy credits in the NEM Breakout COS?

A. Excess generation credits are assigned to each NEM class, as well as an offsetting cost for the excess generation credits that is based on Factor 30 - Energy, and are functionalized in the Company's Production function.[39] Offsetting costs were included in the cost of service model to balance out direct assignment of excess credits to NEM customers. The Company claims that "a fair value"[40] was given to the excess generation credits in the NEM Breakout COS, which recognizes the benefits these credits provide to the system, i.e. reduced net power costs. So, in the NEM Breakout COS, the Company assigns offsetting cost for excess generation credits to all classes, both NEM and non-NEM.

[38] *Id.*, p. 24, lines 486-489.
[39] *Id.*, p. 24, lines 492-495.
[40] *Id.*, p. 24, lines 498-500.

Q. What other differences did the Company's NEM Breakout COS have to address?

A. Like the other COS studies, the NEM Breakout COS study had to estimate the cost to serve Schedule 6, 10, and 23 customers in separate classes because the load research study did not have information for these customers as it did with the residential NEM customers.

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

A. Per the Company's analysis, if NEM residential customers were separated into their own class, non-NEM residential customers would incur $1.1 million less in costs. However, costs for non-NEM customers served under Schedules 6, 8, and 10 would increase by $0.3 million, $0.2 million, and $0.04 million, respectively.[41] The Company claimed that these increased costs are likely more due to the lower DG production from the Schedule 6, 8, and 10 customers compared to their full requirements energy usage. The Company's main conclusion from this analysis was that residential NEM customers do not pay enough to cover the Company's cost to serve them, which is significantly different than serving other non-NEM residential customers.[42] To further emphasize its point, the Company provided a table showing revenue to cost of service parity ratios, which is provided below.[43] The ratio identifies the percentage of the total allocated cost of service of each class, actually paid by the relevant customer class. The highlight of the table is

[41] *Id.*, p. 26, lines 545-546.
[42] *Id.*, p. 27, lines 561-564.
[43] *Id.*, p. 28, line 575.

the 60.6% for residential NEM customers, which shows the revenues the Company collects from them is not close to the cost the Company incurs to serve them.

Table 2 – Revenue to Cost of Service Parity Ratios.

	Parity to Cost of Service		
	ACOS	ACOS W/O	ACOS NEM
Residential	96.0%	96.1%	60.6%
Schedule 23	107.2%	107.3%	92.2%
Schedule 10	95.3%	95.1%	89.8%
Schedule 6	107.7%	107.7%	109.2%
Schedule 8	104.1%	104%	109%

The Company further compares the NEM Breakout COS to the ACOS and CFCOS and finds that the NEM Breakout COS results shows that the residential NEM class revenues collected would need to increase by $1.8 million for the Company to earn the jurisdictional average rate of return.[44] In addition, the Company adjusts the results of the NEM Breakout COS to the same level of costs from its last general rate case ("2014 GRC") to ensure the residential NEM class rates are set on the same basis as the rates for all other customers.[45]

C. Load Research Study

Q. Please describe the Company's load research study that it used for the cost of service studies.

[44] *Id.*, pp. 28-29, lines 582-583.
[45] *Id.*, p. 29, lines 591-595 and 599-601.

A. As I noted earlier, the Company conducted a load research study that collected customer data for all residential NEM and non-NEM customers, as well as non-NEM data for all other customer classes. The Company was only able to get NEM data for 36 residential customers because it was only given permission to install production profile meters to measure 15-minute interval data on the NEM customers' DG facilities (though 52 load research profile meters were installed in total). The load research study spanned 12-months and ended December 31, 2015, which was the test year for the cost of service studies discussed above.

D. Distribution Level Costs and Benefits of DG

Q. Does the Company believe that DG provides any distribution level benefits?

A. No. The Company explains that not only does DG, and more specifically solar DG, not reduce the system peak demand to a level that would help reduce the need for new infrastructure, but it also may lead to increased infrastructure requirements.[46] In addition to not reducing the peak demand, the Company states that NEM customers use the grid at a higher level because they not only consume energy from the grid, but also export energy to the grid which may in some cases overwhelm consumption. Further, the Company claims it incurs additional costs due to applications for interconnection.

Q. Did the Company provide any studies or data to back up its DG cost claims?

[46] Direct Testimony of Douglas L. Marx, p. 2, lines 27-30.

A. Yes. The Company presented results from a rooftop solar study it conducted as part of the 2014 GRC (Docket No. 13-035-184). The purpose of the study was to evaluate rooftop solar's impact on offsetting infrastructure upgrades made by the utility on the Company's Northeast #16 circuit. Results of the study showed that DG was only able to offset seven percent of the peak demand.[47] In addition, the Company conducted a similar study on its Bingham #11 circuit and found a similar result (a 6.8 percent offset[48]). The Company used these results to reinforce its claim that increased DG penetration can lead to increases in distribution system investments to control reverse power flows caused by the DG systems.

Q. What other system analysis did the Company perform?

A. The Company analyzed solar peak output and system peak demand. According to the Company, peak output of solar DG occurs during April or May and output decreases in the summer months (June and July) when system peak demand typically occurs. Further, the Company claims that peak demand occurs in the evening, when solar DG production is at its lowest. Since peak solar DG production is occurring in April and May, the Company explains that "the system may be sized up to 30 percent greater than normal. In a few cases, the reverse power flow could approach 50 percent more as compared to the customer's peak demand."[49] To emphasize a DG customer's grid usage, the Company

[47] *Id.*, pp. 2-3, lines 42-43.
[48] RMP response to DPU 8.1.
[49] Direct Testimony of Douglas L. Marx, p. 4, lines 75-77.

provided a power flow figure showing a 24-hour day in the summer for a typical 5 kW DG customer.[50]

Because of this increased grid usage by DG customers, the Company claims it will need to make the following changes to its distribution system: "[a]dvanced metering to monitor the system, updates in regulator, relay, and recloser controls to account for two-way power flows [to] protect the system, [and] increased levels of voltage management equipment and dead-line checking systems will be required."[51]

Q. What other costs does the Company discuss in relation to DG's impact on the distribution system?

Additional costs of DG to the distribution system include application processing and interconnection, which involves the Company's customer call center, customer generation, and engineering and operations departments. All applications are processed under one of three levels of review. According to the Company, Level 1 applications are about 80% of the total reviewed and apply to DG systems less than or equal to 25 kW that operate with an inverter.[52] Level 2 applications are those that do not qualify for Level 1 and are less than or equal to 2 MW. Level 3 applications are those that do not qualify for Level 1 or Level 2 and are less than or equal to 20 MW. The Company claims that as the level of review increases, the complexity of the review process increases, and so does

[50] *Id.*, p. 6, line 100.
[51] *Id.*, pp. 4-5, lines 85-88.
[52] *Id.*, p. 9, lines 169-170.

the cost, especially for the engineering department. Applications have been continuing to increase each year and the Company is seeking cost increases to application fees to cover the processing of applications.

E. Rate Design

Q. Please explain the Company's proposed rate design.

A. RMP is proposing to implement a three-part rate design for new residential NEM customers based on its cost of service studies. The proposed rates include a fixed monthly charge (customer charge), a time-based demand charge during peak hours, and an energy charge. Additionally, the Company is seeking to place these NEM customers in their own class because they have a different load shape and cost characteristics than other residential customers. The new rates calculated from the proposed rate structure would become effective June 1, 2017. Current residential NEM customers would not be impacted by the proposed rate structure and would remain on their current rate schedule because of the cost to "operationally and administratively"[53] transition these customers to the proposed new rate schedule, including the need to change the current meters to meters capable of capturing and billing the proposed on-peak demand charge. The Company also proposes allowing the current residential NEM customers to opt into the new Schedule 5 rate tariff.

[53] Direct Testimony of Gary W. Hoogeveen, p. 11, line 233.

In addition, the Company seeks to eliminate the average retail rate compensation option currently available for non-residential customers for their excess generation.

III. ISSUES AND ANALYSIS

A. Need for Separate Residential NEM Class

1. Introduction

Q. What reason does the Company cite for putting residential NEM customers into a separate rate class from residential non-NEM customers?

A. The Company suggests placing NEM customers in a separate class because of differences in load shape and cost characteristics. Specifically, the Company claims that NEM customers have lower load factors than non-NEM customers and higher per unit customer costs.[54]

Q. Have you evaluated the Company's claims regarding this issue?

A. Yes, I analyzed the differences in load shapes and costs to serve NEM and non-NEM customers using data from the Company's Load Research Study and the unit costs in the NEM Breakout ACOS study.

Q. Do you agree with the Company's conclusions about the need for a separate rate class for residential NEM customers?

[54] Direct Testimony of Joelle R. Steward, p. 18, lines 341-343.

A. As discussed in further detail in this section of my testimony, I agree there are differences in the cost to serve NEM and non-NEM customers, but I have found the differences are not as great as the Company claims.

Q. Does your analysis consider the impact of excess generation exported to the grid?

A. No, I only evaluated the costs to serve load provided by the grid for both NEM and non-NEM customers.

<u>2. Load Research Study</u>

Q. Why did you analyze the Company's load research study to evaluate whether NEM customers should be in a separate rate class?

A. The Company's load research study evaluates load shapes of NEM and non-NEM residential customers and is used to estimate class load factors. A lower load factor for NEM customers would indicate higher peak loads relative to average loads and vice-versa. If demand-related costs are recovered through energy charges, as is typical for the residential class, then a lower load factor indicates the need for a higher $/kWh rate for the class. The load research results also provide information as to whether NEM customers are similar enough to each other that one rate for all NEM customers would be reasonable.

Q. How are residential NEM and non-NEM customers treated in the Load Research Study?

A. The Company divides all residential customers into four different strata based on kWh/month usage. I provide a table below that summarizes the different strata and provides a NEM vs non-NEM weight to the customers in each stratum. These weights show that NEM residential customers appear to be more heavily concentrated in the lower two usage strata. However, they may be more concentrated in the lower usage strata due to consumption decreases associated with DG production.

Table 3 – Residential Customer Strata Weighted for NEM and non-NEM.

STRATA	NON-NEM WEIGHT	NEM WEIGHT
1: <500 kWh/month	0.29	0.35
2: 500-1,000 kWh/month	0.46	0.46
3: 1,000-2,000 kWh/month	0.22	0.15
4: 2,000+ kWh/month	0.02	0.03

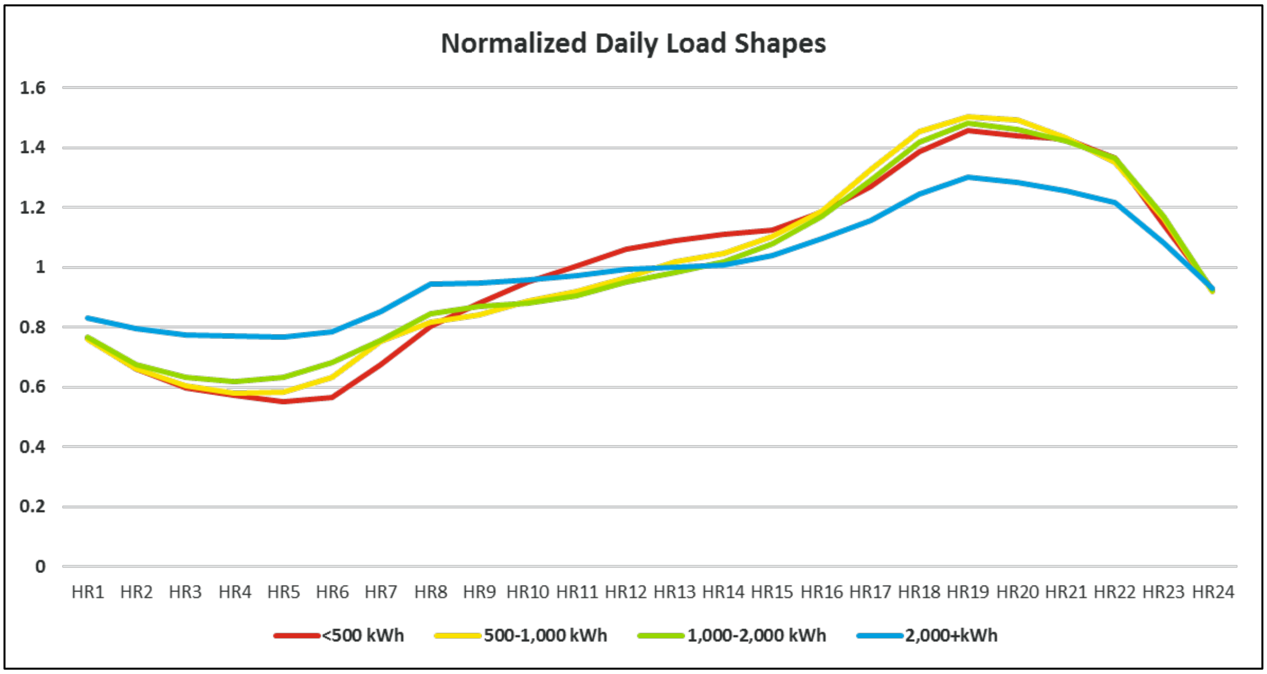
Q. Did you analyze the load shapes of the data collected for the load research study?

A. Yes. I created two figures from the load research data the Company provided in response[55] to UCE 7.8 (residential non-NEM customers) and in response[56] to EFCA 1.3 (residential NEM customers), which are provided below. They show the normalized daily load shapes[57] for residential NEM and non-NEM customers. The residential non-NEM customers, as shown in Figure 1, have very similar load shapes for strata 1, 2, and

[55] See RMP response to UCE 7.8 Attachment [CONFIDENTIAL].
[56] See RMP response to EFCA 1.3 Attachment [CONFIDENTIAL].
[57] Normalized daily load shapes are constructed using the highest consumption value to set the base at 1.0, and then consumption was unitized relative to that 1.0 value to scale load shapes so they can be compared directly to one another regardless of consumption level.

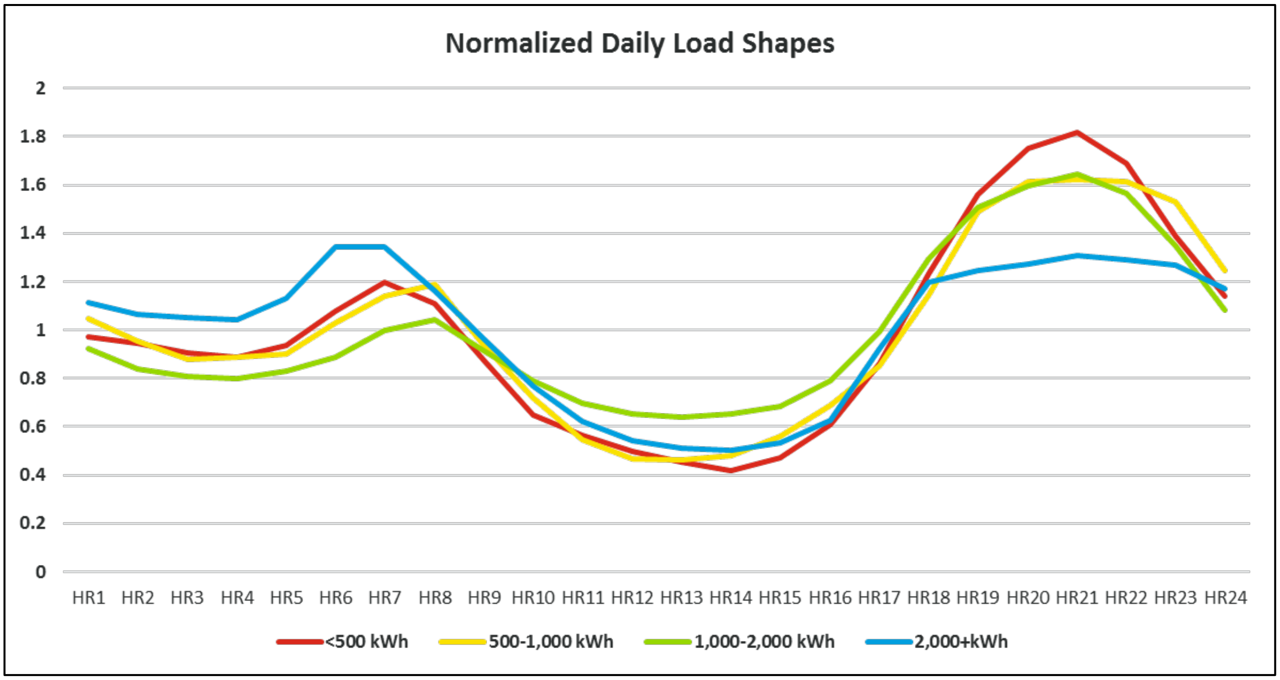
3. Strata 4, which includes the higher-usage customers, has a flatter, but similar load shape and thus a higher load factor.

Figure 1 – Residential Non-NEM Normalized Daily Load Shapes by Strata.



The consumption pattern for the residential NEM customers depicted in Figure 2 is what is known as a "duck curve." This means that all four strata showed a morning peak followed by low midday net consumption (after netting out DG production) that leads up to a more prominent evening peak. As with non-NEM customers, the residential NEM customers had very similar load shapes for strata 1, 2, and 3. Strata 4 had a similar shape to the others, but was flatter.

Figure 2 – Residential NEM Normalized Daily Load Shapes by Strata.

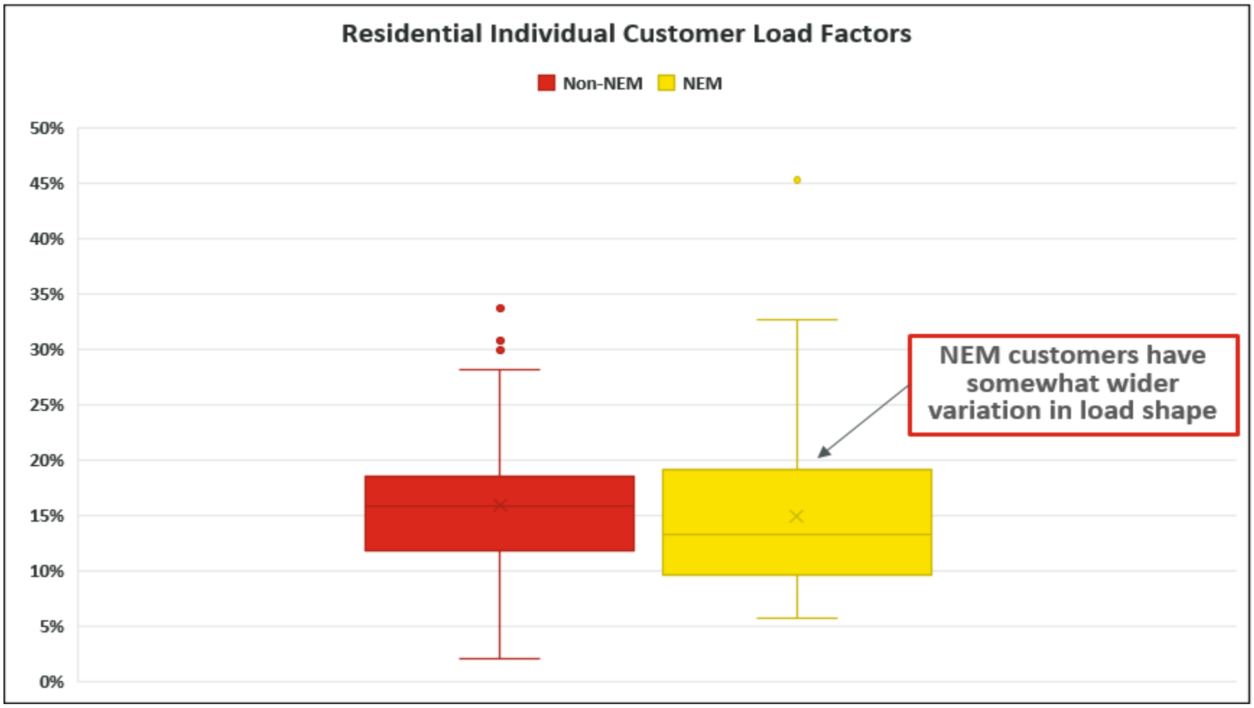


Q. What other data analysis did you conduct?

A. I reviewed the individual residential customer load factors for NEM and non-NEM customers based on the data provided by the Company in its responses to EFCA 1.3 and UCE 7.8. Below I have provided a Box and Whisker plot that demonstrates that NEM customers have a modestly lower average load factor and somewhat wider variation in their load shape.[58]

[58] The Box and Whisker plot shows an "x" and a line in each box that represents the mean of the data and the median of the data, respectively. The whiskers are the lines extending from the top and bottom of each box and indicates the relative distribution of the data. Notice some of the data points are outliers that fall outside of this distribution.

Figure 3 – Residential Individual Customer Load Factors.



In addition to this analysis, I compared residential class load factors for NEM and non-NEM customers based on data from the NEM Breakout ACOS study and from load research data[59] provided by the Company. The table below shows the results of this comparison, which also supports the conclusion that although NEM customers as a separate class have a slightly lower load factor than non-NEM customers, they are not drastically different.

[59] From RMP responses to EFCA 1.3 and UCE 7.8

Table 4 – Residential Class Load Factors.

		Non-NEM	NEM
15-minute Interval	**12 NCP (kW)**	56,098,384	387,862
	Average Load (kW)	744,664	4,466
15-minute Interval	**12 NCP Load Factor**	16%	14%
Hourly Interval	**1 NCP (kW/customer)**	2.94741	3.386
	Average Load (kW/customer)	0.973359	1.053
Hourly Interval	**1 NCP Load Factor**	33%	31%

Q. What do you conclude from your analysis of the Load Research results?

A. NEM customers do have a different load shape than non-NEM customers. More specifically, NEM customers exhibit the "duck curve" shape that has lower midday net consumption followed by a rapid rise in demand at sunset. However, this difference in load shape does not translate into large differences in annual load factors. There is also more variation in the load factors of the NEM customers, but not drastically so. Below I analyze unit costs to see if the load factor differences translate into the need for different rates.

3. Total Unit Costs

Q. What is the purpose of your unit cost analysis?

A. Total unit costs show the allocated COS for each rate class divided by the number of kW, kWh, and customers within the class. A considerably different unit cost would indicate a higher or lower cost to serve each unit of demand or to serve each customer and could indicate the need for a separate rate class.

Q. What are the results of your unit cost analysis?

A. Based on data in the ACOS NEM Breakout study, I determined that the NEM and non-NEM residential customers have similar unit costs, which are shown in the table below. The similarity in energy unit costs are particularly striking. These numbers indicate that if NEM and non-NEM residential customers were in different classes and the Company used a fixed dollar per kWh charge to collect all revenue from residential customers, the rate for each class would only vary by 0.2 cents/kWh. Such a difference, on its own, would not typically warrant the added costs and complexity of creating another rate class.

Table 5 – Residential Class Unit Costs.

	Non-NEM	**NEM**	**Difference**
Total COS/NCP kW	$13.36	$11.82	-11%
Total COS/kWh	$0.115	$0.117	2%
Total COS/Customer	$999.45	$1,044.45	5%

4. Customer Unit Costs

Q. Please explain the difference between total unit costs and customer unit costs.

A. Customer unit costs relate only to costs classified as customer-related in a COS study. Here, I define customer related costs as the costs of the meters, services, and retail subfunctions in the ACOS model. These costs vary most directly with the number of customers. For residential customers, these costs are often collected through fixed monthly customer charges and not energy charges.

Q. What are the customer unit costs for residential NEM and non-NEM customers based on the Company's NEM Breakout ACOS study?

A. The table below shows the customer unit cost for each class. I divided the $/customer annual number by twelve to estimate what the rate would be if the customer costs were collected as a fixed monthly charge. As the table shows, based on the Company's results, NEM customers have close to twice the customer unit costs as non-NEM customers.

Table 6 – Customer unit costs for residential NEM and non-NEM classes showing higher customer unit costs for NEM customers. Per numbers from RMP's NEM Breakout ACOS study.

	RES NON-NEM	RES NEM
Customer Cost ($/customer/month)	$6.64	$12.58

Q What is driving the differences between these customer unit costs?

A. The table below shows the difference in unit costs for each category of customer-related costs. Notice that unit costs for NEM customers are higher for metering, services, and retail subfunctions.

Table 7 – Customer unit costs by subfunction in $/customer/month. Per numbers from RMP's NEM Breakout ACOS study.

	RES NON-NEM	RES NEM
Services	$2.69	$3.30
Meters	$0.65	$1.16
Retail	$3.30	$8.12
TOTAL	$6.64	$12.58

Q. How did residential metering costs differ between NEM and non-NEM customers?

A. NEM customers require a bidirectional meter, meaning a meter capable of measuring both energy flows from and to the grid. These meters are costlier than standard residential meters as shown in the table below.

Table 8 – Residential metering costs for NEM and non-NEM customers. Based on data from the Company's NEM Breakout ACOS study.

Load Class	Standard	Installed Cost	Percent Use	Total Installed Cost / Service
Residential (Non-NEM)				
Small Load	DM221F	$104	92.1%	$95.83
Large Load	DM221G	$139	7.9%	$10.93
				$106.75
Residential (NEM)				
Bi-Directional,				

kW = 0, 1 Phase (sec)	DM221B	$162	100.00%	$162.00

Q. How did residential service drop costs differ between NEM and non-NEM customers?

A. The assumed cost of each type of service drop was the same for residential NEM and non-NEM customers. However, the table[60] below shows that a higher proportion of residential NEM customers were underground service customers. This results in the NEM customer service drop cost being higher per customer because of the higher cost of underground service.

Table 9 – Percentages of NEM and non-NEM customers by overhead and underground service type.

	Residential Non-NEM	**Residential NEM**
OH – small load	31.18%	22.04%
OH – all electric	2.66%	2.34%
UG – small load	60.96%	71.01%
UG – all electric	5.20%	4.61%

Q. Please explain the retail function costs for NEM customers.

A. The higher unit cost of NEM customers is driven largely by the direct assignment of administration and customer service costs to these customers. The table below provides the total dollars the Company assigned directly to the residential NEM class. The total incremental cost is net of Application fee revenue. The revenue for residential customers

[60] In the table, overhead = OH and underground = UG.

in the 2015 test year was only $138, but RMP proposes to increase this fee as is discussed in a later section of my testimony. With an increased application fee, it would not be necessary to recover these costs through the customer charge.

Table 10 – Retail function costs for NEM customers.

	Residential NEM	Schedule 23 NEM
Estimated Incremental Cost of Administration	$198,752	$16,110
Application Fee Revenue	($138)	($7,404)
Estimated Incremental Cost of Customer Service Cost	$75,247	$4,415
Total Incremental Cost of Administration & Customer Service	$273,861	$13,120
Total Cost/Customer/Month	$5.20	$3.35

Q. Please explain the Company's Residential Customer Charge proposal.

A. The Company proposes to increase the customer charge to more than double the current amount. The new proposed customer charge includes all service, meter, and retail function costs plus a transformer cost.[61] The charge is estimated net of expected revenue from the Company's proposed application fee. The table below highlights the cost differences in the customer charge and minimum bill by phase type under the current and proposed customer charge regime.

Table 11– Comparison of Current and Proposed customer charge.

		Current	Proposed
Customer Charge	**1-Phase**	$6.00	$15.00

[61] See Direct Testimony of Joelle R. Stewart, Table 3, p.15 and pp. 22, 25-27; Approved Tariff.

Customer Charge	**3-Phase**	$12.00	$30.00
Minimum Bill	**1-Phase**	$8.00	$15.00
Minimum Bill	**3-Phase**	$16.00	$30.00

Q. Please explain the issues with costs the Company is including in its proposed customer charge.

A. The Company is proposing to include a customer charge for new NEM customers that "is designed to recover costs related to customer services and certain components of the distribution system, specifically service lines, meters, and line transformers".[62] While a customer charge is typically designed to recover customer-related costs, it does not typically include transformer costs. In fact, the Commission has been consistent since its 1982 Order[63] detailing costs a customer charge should recover, and they do not include transformer costs.

Q. How much would residential customer charges increase if designed to recover transformer costs?

A. Featured below is a table outlining the transformer costs by NEM and non-NEM customer class per the Company's NEM Breakout ACOS model. Based on these numbers, recovering transformer costs through the customer charge would increase that charge significantly, but even more so for NEM customers than non-NEM customers.

[62] Direct Testimony of Joelle R. Steward, p. 22, lines 403-405.
[63] Docket 82-057-15, Aug 12 1983, Questar Gas Company case. There was a later docket with PacifiCorp, 84-035-01 Jul 1, 1985.

Table 12 – Transformer unit costs per customer. Based on data from the Company's NEM Breakout ACOS Study.

	Res Non-NEM	Res NEM
Per Customer per Month	4.21	7.53

Q. Why does the Company recommend that transformer costs be recovered through the customer charge for NEM residential customers?

A. Ms. Stewart argues that "a large proportion of the costs of these transformers do not vary with capacity and are fixed infrastructure costs necessary to serve customers"[64] The Company has argued that the additional distribution system costs associated with NEM systems—such as transformer upgrades to accommodate bidirectional flows—justifies different treatments of transformer costs for rate design.

Q. Do you agree that transformer costs should be included in the customer charge for any customer class because a large portion of the costs are fixed costs?

A. No. In my previous testimony[65], I did not recommend that transformer costs be included in the customer charge for residential customers, and I stand by that recommendation. Although these costs may be considered fixed, this does not by itself justify their inclusion in the customer charge. The customer charge should generally consist of costs that truly vary with the number of customers, which would not include the costs of all fixed utility plant.

[64] Direct Testimony, pp. 26-27.
[65] Docket 13-035-184, Faryniarz Direct Cost of Service Testimony for DPU - 05-22-2014 - Exhibit 11.0 DIR-COS. Docket 13-035-184, Faryniarz Rebuttal Cost of Service Testimony for DPU - 06-26-2014 - Exhibit 11.9 REB-COS.

Q. Do you agree that increased distribution transformer costs for NEM customers justifies the recovery of transformer costs in the customer charge?

A. No. Just because the cost is higher for a given class does not mean it should be recovered in the customer charge. Customer charges should recover customer-related costs, and transformer costs do not vary directly with the number of customers. If there is a need for transformer upgrades to interconnect a DG system, then the cost of the upgrade is best recovered from the connecting customer through an interconnection charge. I discuss these charges in more detail later in my testimony.

Q. Did you find any other issues with the discussion of transformer cost allocation in Ms. Stewart's testimony?

A. Yes. There are inconsistencies in terms of how transformer costs are classified by the Company. In Table 5 (p.20) of Ms. Stewart's testimony, which purports to show the significance of demand-related costs in a utility's COS, transformers are featured as demand-related costs. Then later in her testimony when attempting to justify the inclusion of transformer costs in the customer charge, she argues the costs are mostly customer-related. This seems to indicate some cherry-picking in how the Company presents these costs in its analysis.

Q. The numbers in Table 12 above also indicate that transformer costs for NEM customers are significantly higher per customer than non-NEM customers. Do you agree with this finding?

A. No. Transformer costs are allocated using a 1NCP allocator. The NCP for NEM residential customers increases uniformly throughout the test year as previously non-NEM customers switch to NEM service. Therefore, the NCP for the NEM residential class is in December, at the end of the year. The NCP for the non-NEM residential class is in July. This double counts some customers that switch to NEM service between July and December and, therefore, over-allocates costs to residential customers. If we use the July NCP for both residential NEM and non-NEM customers, the transformer unit costs for NEM customers decreases to $5.32/customer.

Q. What do you recommend regarding transformer cost allocation?

A. I recommend the Company ensure that the transformer allocator does not double count customers in its NCP calculation. This should reduce costs allocated to the NEM residential class for the NEM breakout ACOS study.

5. Conclusions

Q. Should NEM customers be segregated into their own class from non-NEM customers?

A. Based on my analysis and findings described above, it is not necessary, for now and at the current level of penetration, to separate NEM customers into their own class. As I explained earlier, the NEM load profiles are somewhat different than the non-NEM load profiles, especially during the middle of the day, but on average fall within a reasonably similar range (see Figure 3 presented previously).

In addition, I do not conclude that a separate class for NEM customers is warranted in order to increase customer charges for these customers. NEM customers do require modestly higher metering costs, but that difference alone does not justify a higher customer charge. Changes in service drop costs are driven more by other characteristics of the customers, such as placement on the underground or overhead system. Additional administrative costs for the NEM program—if assigned only to NEM customers—or increased transformer costs necessary to accommodate bidirectional flows, are best recovered through an alternative charge such as an application fee or interconnection fee as discussed later in this testimony.

Despite this, I do not object to the separation of NEM customers into a separate class if deemed appropriate for other policy reasons, or to address compensation rates for excess generation exported to the grid, which I turn to next.

B. Importance of Net Energy Metering Excess Generation Credits for Residential Customers

Q. As described in the previous section of your testimony, you did not find a significant difference in the costs to serve NEM versus non-NEM residential customer load. If so, what is driving the difference in revenue parity to COS shown in Table 2 above?

A. As I previously indicated, my analysis of the need for a separate class for NEM residential customers did not account for credits for excess generation exported to the grid. As I explain in more detail below, compensation for these exports at retail rates is the primary driver of the low revenue parity ratio shown in Table 2 for NEM residential customers.

Q. How does the Company credit distributed generation (DG) exports in its NEM Breakout ACOS model?

A. Excess NEM generation is credited at average net power costs (NPC) grossed up for transmission and distribution losses. These are shown in the table below.

Table 13 – Credit rates for excess NEM generation credits in Company NEM Breakout ACOS study.

	NPC + Losses
Summer (cents/kWh)	2.8304
Winter (cents/kWh)	1.9539

Q. Do residential customers currently receive compensation for grid exports based on NPC rates?

A. No. NEM customers are in effect reimbursed at retail energy rates because they are billed for the net of total consumption minus total exports. Current retail rates for residential customers are summarized in the table below. They are much higher than average NPC.

Table 14 – Current residential energy charges for RMP customers. Tiers apply based on kWh consumed each month with higher tiers applicable to higher levels of consumption.

	Tier 1	Tier 2	Tier 3
Summer (cents/kWh)	8.8498	11.5429	14.4508

Winter (cents/kWh)	8.8498	10.7072	N/A

Q. If excess NEM generation is credited at retail rates instead of average NPC, how does that change the COS results?

A. To answer this, I increased excess NEM credits to the highest tier retail rates in the Company's NEM Breakout ACOS model. The result is summarized in the table below. Parity to COS for residential NEM customers increases drastically: from 60.6% to over 90%, bringing it much closer to the parity ratio for non-NEM customers.

Table 15 – Parity to COS for NEM and non-NEM customers assuming different rates NEM export credit rates.

	Credit at Net Power Cost	**Credit at Retail Rate***
Non-NEM	96.1%	96.0%
NEM	60.6%	90.5%

* Assumed Highest Tier Rate: 10.7072 cents/kWh (Winter) 14.4508 cents/kWh (Summer)

Q. Please elaborate on the significance of the excess NEM credit rate to the NEM breakout ACOS results.

A. The results in the table above demonstrate the importance of valuing excess NEM generation consistently in an ACOS study. The results indicate that if one accepts the Company's COS methodology and then compensates excess NEM generation at a rate based on NPC plus losses, and if residential NEM customers were in a separate class but paying the Company the same rate as other residential customers for the load served from the grid, revenues from NEM customers would cover on the order of 90% of cost of service, not the 61% covered today when excess generation is compensated at full retail rates. The remaining difference in parity to COS between non-NEM and NEM customers, that is the difference between the 96% and the 90%, is due to other differences in the COS for these customers, such as from different load shapes or unit costs discussed in the previous section. Those differences are, notably, much smaller.

Q. Is the value of excess NEM generation also a key driver to the CFCOS results?

A. Yes. The CFCOS study attempts to estimate costs to the utility if the customer generation from NEM facilities did not exist. The added costs are largely from increased NPC at the rates shown in the table below. These rates are similar to the NPC rates used in the NEM Breakout ACOS, but of course much lower than residential retail energy rates. Therefore, under the Company's assumptions, if one adds the NEM generation back to the CFCOS, costs decrease less than utility revenues, indicating the NEM program results in a net cost to other customers and the utility.

Table 16 – Average cost of additional NPC assumed to be required to generate power to replace generation from NEM customers in CFCOS study.[66]

	Added NPC in CFCOS
Summer (cents/kWh)	2.9334
Winter (cents/kWh)	2.1692

[66] See Exhibit RMP_(MGW-1) and see RMP response to DPU 6.12-1, Exhibit RMP_(MGW-1) CORRECTED.

Q. Is there a strong logical basis for valuing excess NEM generation at retail rates?

A. No. Retail rates are based on the total costs to serve customers from a grid-based system, which has nothing to do with the costs of supplying power from DG systems. Thus, they are not equivalent to the benefits of DG systems. Moreover, the ability to export and receive compensation at retail rates allows customers to effectively zero out their energy bills as long as total generation is equal to total load consumed, regardless of the time the energy is consumed or generated.

Consider an extreme case, where a utility served only such customers. The utility would receive no revenue even though it would incur significant costs to store the excess energy and supply it back to customers. Thus, traditional NEM excess energy compensation, at full retail rates, is not sustainable in the long-run with very high rates of DG penetration.

Q. What possible options exist for valuing exports?

A. Besides the de facto retail rate reimbursement paradigm, exports could be valued numerous ways. These include using the avoided costs of fuel and purchased power (short-term), generation capacity (long-term), or the avoided costs of utility-scale renewable resources. Additional costs and benefits to the transmission and distribution systems could also be considered, as well as environmental benefits and local economic benefits. I turn to these factors next.

C. NEM Costs and Benefits

Q. The Company's response to OCS 6.7 discusses several costs and benefits that were either included or excluded from the cost of service studies. These costs and benefits include the following: NEM added Program Administration Costs, NEM added Integration costs, NEM added Distribution Costs, NEM added Lost Revenues, Avoided Energy Costs, Avoided Capacity Costs, Avoided Transmission Costs, Avoided Distribution Costs, Avoided T&D Line Losses, and Avoided Environmental Compliance. Do you agree with the Company's inclusion/exclusion of each of these costs?

A. In general, the foregoing categories of costs and benefits of NEM appear reasonable for the Company to consider including in its cost of service studies. For each of the NEM cost categories, the Company included these costs in its cost of service studies. Regarding program administration costs, the Company explained that it has one department across the six states it serves that is responsible for administering the NEM programs. Costs are assigned to each state proportionally based on overall department expenses allocated to each state's NEM program. Application fee revenues from large non-residential interconnections collected in 2015 reduced the total expense. After review of the total expenses allocated to each state, calculated in Exhibit RMP_(RMM-7), the allocation of the Company's NEM department's expenses to Utah appear to be reasonable.

The Company included NEM integration costs in its net power costs because these costs are incurred when integrating new private distributed generation into the system, which includes added reserves needed to handle the private DG's intermittency (i.e. inability to continuously supply a customer's full power needs). Integration costs can increase or decrease the net power costs depending on if private DG is added or taken off the system. The Company explained that it used solar integration costs in its net power cost analysis of $2.83/MWh.[67]

The Company states that the NEM program adds incremental metering and engineering costs to the distribution system.[68] The engineering expenses are solely related to the time engineers spend reviewing NEM applications, which can vary in complexity.[69] Incremental metering costs are related to replacing and reprogramming[70] customers' current meters with bi-directional meters that can measure the flow of energy to and from the installed DG facilities. When estimating the percentage of meters that can be reprogrammed versus replaced, the Company bases the percentages of either option on the current proportion of meters that have been reprogrammed or replaced.[71] Both costs seem reasonable, as detailed in exhibits[72] provided by Company witness Mr. Meredith.

The Company considered lost revenues associated with the NEM program as a cost due to bill credits. Bill credits are calculated based on the difference between the Company providing customers full energy requirements and the actual energy customers are billed

[67] This is consistent with the Commission's Order in the QF Docket. Docket No. 12-035-100, Order on Phase II Issues, at 34 (Utah P.S.C. August 16, 2013). Direct Testimony of Michael G. Wilding, p. 8, lines 138-140.
[68] RMP response to OCS 6.7(c). Direct Testimony of Robert M. Meredith, p. 17, lines 328-347.
[69] See Exhibit RMP_(RMM-8) for a breakout of the engineering expenses by customer class.
[70] Residential customers need to have their current meters replaced, while some non-residential customers have meters capable of measuring the bi-directional energy flows, but need to have the meters reprogrammed to do so.
[71] See Exhibit RMP_(RMM-9), Page 1&2, Notes.
[72] Exhibits RMP_(RMM-8) and RMP_(RMM-9).

for each month.[73] A revenue difference is calculated based on multiplying the corresponding energy charges by the difference between providing full energy requirements and billed energy. In calculating the bill credits related to the NEM program, the Company relied on the results of the CFCOS (without DG) versus the ACOS (with DG).[74]

All the costs the Company considered for the NEM program appear reasonable as costs to consider. However, as discussed earlier, reliance on the CFCOS results may lead to inaccurate NEM program costs. Since the CFCOS is based on going back in time and assuming the Company needed to provide full requirements service to all customers, the Company is assuming the private generation plus the actual billed energy for each customer would be equal to each customer's total energy needs.

Q. Do you agree with the Company's inclusion/exclusion of each of the benefits listed above?

A. First, the list of benefits that the Company was asked if it considered in its cost of service studies is not a complete list of all possible benefits that could be reviewed, i.e. several types of environmental or economic benefits could also be analyzed. Second, many of the avoided costs were not explicitly included by the Company in its cost of service studies. For example, the Company explains that avoided transmission costs, avoided distribution costs, and avoided environmental compliance are not explicitly included, but instead are

[73] The Company created seasonal energy blocks and on-peak and off-peak periods when it could do so.
[74] See Exhibit RMP_(RMM-5).

considered a "benefit for reduced allocations of existing costs" [75]. Further, the Company explained that during the cost of service study period, which is a one-year test period starting January 1, 2015, the transmission costs, distribution costs, and environmental compliance costs "were not reduced as a result of the NEM program" [76]. Since the Company is using a one-year historic test-period as discussed from the Phase I Commission Order, it is likely that any long-term transmission, distribution, and environmental compliance avoided cost benefits may not be able to be properly captured.

Avoided distribution costs, which potentially can reduce the need for the Company to replace, upgrade, or expand its distribution system capacity due to system or localized peak reductions, would need to be analyzed over a longer period of time and should also be analyzed for providing location-specific benefits when possible. The Company did complete two location-specific analyses (Northeast #16 and Bingham #11 circuit studies), which it stated resulted in rooftop solar minimally reducing the peak circuit loading in two different locations.[77] In addition, the Company claims that it "will need to increase the size of the local distribution system to handle the reverse power flow delivered to the grid by the customers".[78] While these two studies do indicate minimal localized circuit peak load reduction on the selected circuits, it is possible that rooftop solar may have greater impacts on other circuits or help further reduce the system peak, since there has

[75] RMP response to OCS 6.7(g), (h), and (j).
[76] *Id.*
[77] Direct Testimony of Douglas L. Marx, pp. 2-3, lines 38-54.
[78] *Id.*, p. 3, lines 62-63.

been an exponential amount of solar added to the Company's system over the last few years.

However, it will be important to address how, if at all, such potential reductions might be reflected in base rates or compensation levels for NEM customers because such benefits do not fit well within traditional test year studies.

Furthermore, the reverse power flow issue that Company witness Marx describes is not addressed in Exhibit RMP_(DLM-1), the July 26, 2015 Distribution Rooftop Solar Study, nor is it presented by the Company in any quantifiable way.

Q. How did the Company include avoided energy and capacity costs in its cost of service studies?

A. The Company explained that avoided energy costs were "included as a benefit for reduced NPC as well as for reduced energy based allocations" and avoided capacity costs were "included as a benefit for reduced demand based cost allocations".[79] In calculating the benefits of the NEM program to the NPC, the Company went from a system with private distributed generation to one with no private DG, meaning the Company would have to provide full requirements energy to all customers. This included changes to the amount of generation and market transactions to make up for the loss of private DG. RMP explained that net benefits to the system from private DG were calculated by

[79] RMP response to OCS 6.7(e) and (f).

multiplying the actual costs of generation and market transactions by the incremental changes to each needed to make up for the loss of private generation.[80] Then, since DG interconnection costs are treated as an avoided cost in the NPC calculation, the $2.83/MWh for solar DG interconnection costs is treated as a reduction to the NPC. So, the Company reduced the total unit value of solar in $/MWh by the $2.83/MWh integration cost before multiplying the total unit value of solar by the MWh generation from private generation to get the total net power cost benefit of the state's NEM program.[81]

The Company created a standardized production profile using data from 36 production profile meters that were installed on private DG systems during the load research study. This production profile enabled the Company to estimate private DG production, which the Company would need to supply customers in the CFCOS study because they no longer have such private generation to rely on for part of their energy needs. So, the loss of private DG production would result in an increase in demand in the state, and could potentially increase state load interjurisdictional allocations (whether they be interstate or intrastate). Thus, the CFCOS had its allocation factors modified to reflect what they would have been without private DG production.

Q. Did the Company include a benefit for avoided line losses, and if so, how?

[80] Direct Testimony of Michael G. Wilding, p. 2, lines 33-35.
[81] This was done monthly.

A. Yes. The Company had to figure out the line losses applied to private generation to calculate the avoided line loss benefit to the system. RMP explained that it determined the nameplate installed capacity each month for customers served at both the primary and secondary voltage levels. Then the Company used loss factors from a 2015 COS study for the nameplate capacity quantities to expand the private generation by class and ultimately bring it to the input level.[82] While the Company's method to calculate avoided line losses is a reasonable proxy, it could potentially under- or over-estimate actual line losses avoided, depending on distance to certain generation facilities, distribution line length, and distribution equipment for each customer.

Q. Are there other avoided costs or benefits to the distribution system the Company should have considered in the cost of service studies?

A. There are other potential avoided costs or benefits to the distribution system the Company could consider in its cost of service studies, insofar as they are quantifiable and not double-counted. These possible benefits of DG to the distribution system include environmental, societal, and market benefits.

Notably, in its July 1, 2016 Order, the Commission explained that benefits should be within the Company's control. However, environmental, societal, and market benefits are typically not considered within the Company's control. In addition, the Company actively

[82] Direct Testimony of Robert M. Meredith, p. 14, lines 267-274.

does environmental control, and any environmental benefits in addition to that could be considered double-counting in this category of benefits.

In other jurisdictions, Commissions have considered these benefits of DG to the distribution system, but have typically done so through opening separate dockets or proceedings. The reason for separating out costs and benefits in a different docket is to allow for proper, focused analysis and stakeholder vetting of each.

Q. Should the Utah Public Service Commission consider expanding the current docket or opening a separate proceeding to ensure a robust analysis of DG benefits and costs over a longer planning horizon?

A. Yes. I would recommend that the Commission consider opening a separate docket to properly vet possible DG costs and benefits to RMP's distribution system, potentially to include parties to the current docket and all stakeholders with an interest in DG. Such a process would take considerable time but need not forestall transitional rate changes in the interim that might lead to better-designed rates than currently exist.

D. Residential Demand Charge for new NEM Customers

Q. Please explain the issues with implementing a demand charge.

A. Using demand charges to recover transmission and distribution ("T&D") costs can be justified under cost causation principles, as T&D systems are designed to meet aggregate peak demand and are mostly fixed cost in nature. Coincident or TOU demand charges, which have been proposed by the Company, can send a better price signal than demand charges based on maximum billed demand in each billing cycle, and thus will better reflect the cost causation principles of ratemaking. This may be largely academic, however, since metering currently in place, outside of the load research study[83], does not allow for measurement of coincident or TOU demands.

It would also be difficult to implement demand charges for residential customers at this point for several reasons, including higher costs for new metering that would be necessary for implementing such charges, as well as a lack of and cost for customer outreach and education, and anticipated issues with general customer acceptance.[84] Because demand charges, with or without ratchets[85], can affect customer bills significantly, there is also the potential for significant rate shock and dislocation, which would violate another key ratemaking principle of rate stability.[86]

Q. What would you recommend regarding demand charges?

A. Demand charges have the potential to better reflect cost causation on the distribution system, especially if they are based on coincident peak or are time-differentiated. However, based on issues regarding the installation and cost of required metering capable

[83] *Id.*, p. 10, lines 183-186.
[84] See additional discussion of these topics in *Distributed Energy Resources Rate Design and Compensation*: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design (November 2016), pp. 98-108.
[85] An example of a ratchet is when the demand charge is based on historical peak demand. If the peak demand from the previous summer was 100 kW and a company had a 50% ratchet, the minimum billing demand would be 50 kW (100 kW times 50%) for a set number of months. Under this structure, it would not matter if actual demands were lower.
[86] Bonbright, James C., *Principles of Public Utility Rates*, pp. 383-384 (1988) (rate structure characteristics).

of recording demands over all hours of the billing cycle, customer acceptance and understanding, ability to monitor and control electricity bills, and the potential for rate shock and dislocation, I recommend demand charges be implemented gradually. Further data collection, including on DG and non-DG customer load shapes and the impacts on residential customers where such charges have been implemented in other jurisdictions, is warranted to better understand the effects of demand charges on gross and net consumption and how these charges would impact DG resource development on a forward-looking basis. I recommend the Commission concurrently consider alternative rate designs or other ratemaking tools to address problems with current rates.

Q. What alternatives to demand charges could be considered?

A. *Demand* charges that are time-based or based on coincident peak demand can be effective at signaling the times of highest long-term cost on the aggregate utility system, including the distribution system. On the other hand, a TOU or other time-differentiated *energy* rate with higher charges during hours of the day when the residential class typically peaks (i.e., early evening), would also reflect cost causation and send an appropriate price signal.

TOU pricing is generally viewed more favorably among a broad variety of non-utility stakeholders, and may be preferable at this point to the proposed demand charges or other fixed charges. Properly-designed TOU or other time-differentiated energy rates can reflect changes in hourly energy prices throughout the daytime and seasons and therefore serve as an appropriate determinant for recovery of many fixed costs associated with T&D service as well as better reflecting market prices for energy. Under TOU or other time-differentiated energy rates, regardless of when a customer sets a peak demand, the customer still has an incentive to adjust energy consumption, add DG, or both, in response so that it can benefit from lower bills if the customer can shift usage to lower TOU rate periods going forward. In addition, the use of super or "critical" peak TOU periods during times of peak demand on the overall system and/or the utility distribution system could also help ensure recovery of T&D costs without introducing demand charges. TOU energy rates, like demand charges, rely on the installation of metering capable of capturing hourly interval demand data. So, these rates will also incur higher meter costs to implement and may suggest that other intermediate steps might be preferable in the near term to address shifted costs. Division witness Dr. Artie Powell will address these steps.

Q. What would you recommend regarding TOU-based energy rates?

A. TOU or other time-differentiated energy charges may more closely align NEM rate design with cost causation principles, if metering can be implemented to measure customer imports and exports separately over all hours of the billing cycle, to reflect hourly and seasonal differences in wholesale power supply costs and the peak demand periods which T&D systems are built to meet. The design of TOU or other time-differentiated rates would be informed by additional data collection and analysis to better understand the impact of such rates have sending price signals to the NEM customer so they shift their loads out of the peak, higher cost periods. Data collection through a rate pilot program(s) could enable the Commission to make more informed decisions about different time-based rate structures going forward.

Q. What do you conclude regarding the use of demand charges and TOU-based rates?

A. I support the consideration of both a demand charge schedule and TOU schedule to allow for customer choice, as noted in Division Witness Dr. Artie Powell's Direct Testimony.

E. Gradualism

Q. Please explain how any rate design approved by the Commission should be adopted.

A. Regardless of the ultimate rate design and rates approved by the Commission, the rate design and rates should be gradually implemented through steps that enable proper transition to bi-directional meters and avoid or mitigate adverse average rate and bill impacts for customers. It will take time for the Company to replace or reprogram meters that capture bi-directional energy flow, proper customer outreach, and for customers to adjust to the new rate structure(s) by altering usage patterns to coincide with the change in price signals.

F. Grandfathering

Q. Did the Company address grandfathering of current NEM customers in its testimony?

A. No. The Company only addressed the fact that current residential NEM customers would not be placed under the proposed Schedule 5, but could voluntarily opt in if desirable. Grandfathering considerations are important because of the potential for discrimination between current versus future NEM customers. It is practical to employ grandfathering, along with gradualism, during a rate design transition process to minimize customer impacts and allow the Company to get the proper metering infrastructure and billing set up to handle a new rate design(s). After an appropriate transition period, all NEM customers could likely be subject to the same rate design.

Under the Utah NEM Statute, the Company must have a NEM program, but that program can be capped in size. The current cap size set by the Commission can be adjusted downwards to a lower level, which would help usher in the beginning of a transition period where grandfathering of current NEM customers can be used to help those customers adjust to a future rate design(s). In short, by decreasing the NEM program cap to a level near the current program size or a near-term projection of size, the Commission can create a defensible class of NEM customers that might be gradually transitioned while newcomers after the Commission’s order in this proceeding might have a new regime immediately applied.

G. Interconnection Application Fees

Q. Please explain the interconnection application fees proposed by the Company.

A. The Company is proposing to implement a Level 1 interconnection application fee, as well as increase the current Level 2 and Level 3 interconnection application fees already in place. The interconnection application fees are charged by the Company to cover the NEM program administration and engineering costs when customers looking to add private DG apply for interconnection. These costs cover the Company's customer call center costs of handling all three levels of applications, as well as the customer generation, and engineering and operating costs of reviewing each of the applications. As the Company suggests, each level of application carries with it increasing complexity and therefore adds to the overall interconnection costs to properly integrate increasing levels of DG at any point on the system.

Currently, only Level 2 and Level 3 applications have been charged interconnection application fees. However, as the Company has explained "[a]pproximately eighty percent of applications reviewed are satisfied at Level 1."[87] In addition, the Company continues to experience an increasing volume of applications and is considering ways to automate the application process.[88] In support of the Company's implementation of an application fee for Level 1, it explains that California and Washington have implemented application fees for smaller systems.[89]

[87] Direct Testimony of Douglas L. Marx, p. 9, lines 169-170.
[88] *Id.*, p. 11, line 197, Figure 2.
[89] *Id.*, p. 12, lines 210-215.

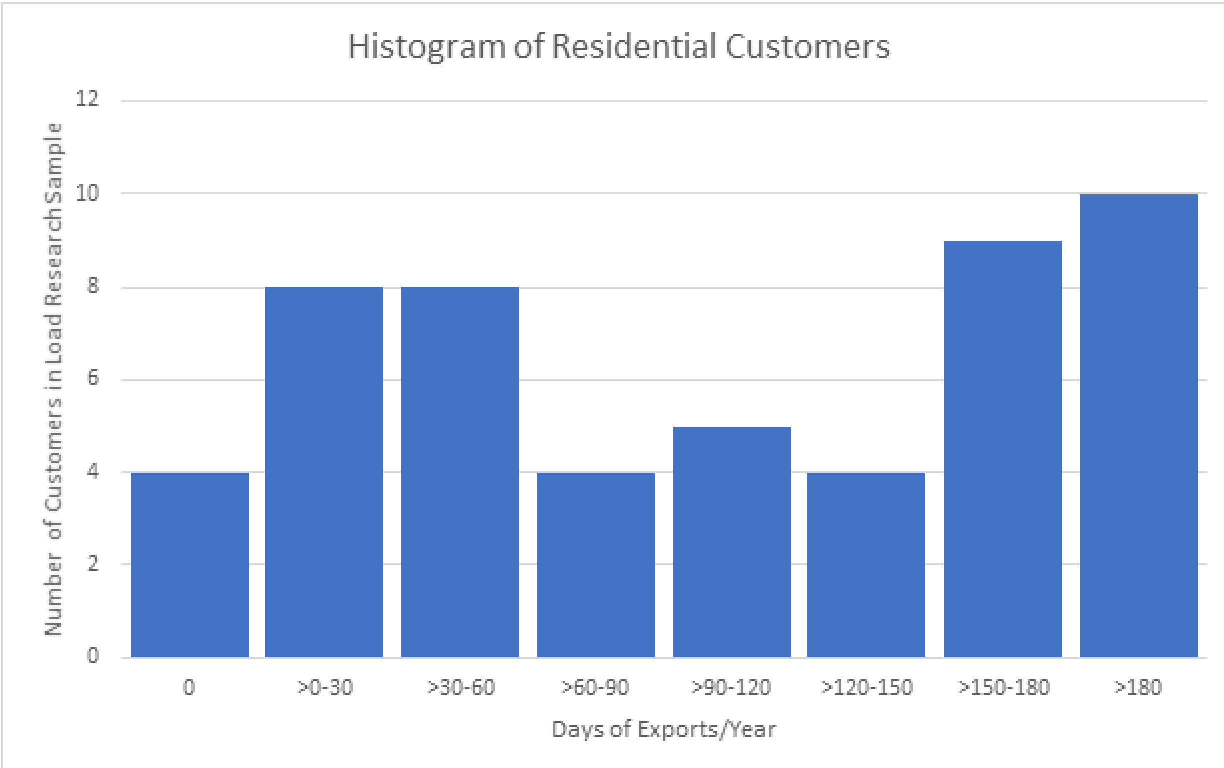
Q. Do you agree with the Company's proposal to increase interconnection application fees for all three levels of application?

A. In general, I agree with the Company that there is a cost of interconnection incurred for both program administration and engineering review when a customer submits an interconnection application for any system, regardless of size. These costs should be borne only by the applicants, since non-NEM customers are not contributing to these costs. Note as well that it is standard in the electric power industry for generation developers to pay for costs to interconnect to the grid.

Because of the potential for additional costs to deal with reverse power flows, I also recommend that interconnection costs vary based on whether the interconnecting DG system is expected to export power to the grid. Based on the Company's load research results, some residential customers export most days, while others not at all. The distribution of the frequency of exports is shown in the chart below.[90]

[90] See RMP response to EFCA 1.3 Attachment [CONFIDENTIAL].

Figure 4 – Frequency of exports of residential NEM customers based on load research study results.



<u>H. Non-Residential Customers</u>

Q. How do the NEM Breakout ACOS results vary for residential and commercial classes?

A. As shown in Table 2 previously, revenue parity ratios for commercial NEM classes were lower for Schedule 23 and Schedule 10 classes but higher for Schedule 6 and Schedule 8. For classes that had lower revenue parity ratios, the difference between NEM and non-NEM customers was not as large as with residential customers.

Q. What factors contribute to the difference in results for residential classes and commercial classes?

A. The difference reflects the different rate structures for these classes. Except for small customers on Schedule 23, commercial classes listed in Table 2 have demand charges and lower energy charges than residential customers. Customer maximum demand can be reduced by solar DG systems if the maximum demand level in the absence of DG occurs during daylight hours, but the amount of reduction from solar DG is limited to the difference in maximum demand during daylight hours and maximum demand in non-daylight hours. Put another way, a customer cannot fully zero out its demand charge with a solar system unless it has an energy storage system such as a battery, because demand will be placed on the grid when the solar system does not generate.

Lower energy charges also create a lower rate of compensation for some exports to the grid. Under current tariffs, commercial NEM customers are billed for their net energy consumed each month as long as exports to the grid are less than energy consumed from the grid. For these customers, exports are all compensated at the retail energy rate. If exports exceed energy consumed from the grid, the net credit for excess NEM generation is valued either at an avoided cost rate from Schedule 37 or a total average retail rate. Since total average retail rates are higher than avoided costs, to date commercial NEM customers have all chosen this compensation option.[91] For these customers, exports then

[91] Direct Testimony of Joelle R. Steward, p. 33, lines 637-638.

have two different compensation rates: the retail energy rate up to the level to net out all energy consumption and then the total average retail rate for the excess.

The Company proposes to eliminate the option to value excess NEM credits at total average retail rates, which would lower export compensation levels significantly for customers with excess NEM bill credits.

Q. Do your conclusions and recommendations regarding residential NEM customers also apply to commercial NEM customers?

A. Most of them do, yes. The analysis supporting placing residential NEM customers in a separate class is specific to residential customers, and the Company does not propose to place commercial NEM customers into a separate class from non-NEM customers. My other conclusions, namely on the importance of correctly valuing exports, NEM costs and benefits, and the use of application fees and interconnection fees also apply to all NEM customers.

Q. Did you do any further analysis of commercial NEM customers?

A. Yes. I analyzed Schedule 23 NEM customers and their differences from Schedule 23 non-NEM customers. I focused on these customers because some of them are similar to residential customers in that they do not pay demand charges and the NEM breakout ACOS results show a lower parity ratio for NEM customers in this class compared to non-NEM customers. Moreover, customer-related costs are a more significant portion of the total bill for small commercial customers compared to large commercial customers.

Q. What data did you analyze for Schedule 23 NEM customers?

A. Load research for these customers was not available, but I did analyze differences in customer unit costs between NEM and non-NEM Schedule 23 customers from the NEM Breakout ACOS study.

Q. How do Schedule 23 metering costs vary for NEM and non-NEM customers?

A. Based on the results in the Company's NEM Breakout ACOS, metering costs per customer are about equal for NEM and non-NEM customers, but this may be due to an error in the COS model.

Q. Explain the possible error in allocating Schedule 23 metering costs.

A. It appears that RMP mistakenly uses the cost of a bidirectional meter for residential customers ($162/meter) for allocating metering costs to Scheduler 23 customers.[92] This cost is less than the cost of a meter for non-NEM Schedule 23 customers. If we assume NEM and non-NEM Schedule 23 customers have similar metering costs per meter, NEM metering costs would be $238 per meter not $162. Also, since bidirectional meters are costlier, the cost of meters for Schedule 23 NEM customers should likely be even higher than $238.[93]

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[92] Based on data from the Company used to create the metering cost allocator in the NEM Breakout ACOS.
[93] See RMP response to OCS Data Request 4.2 Attachment [CONFIDENTIAL], which discusses the kinds of meters

Q. Explain the differences in customer costs between NEM and non-NEM customers after the rectification of the metering cost error.

A. After using an average unit cost of $238 per meter for Schedule 23, customer unit costs for Schedule 23 NEM customers were higher than non-NEM Schedule 23 customers in all categories of customer-related costs I analyzed. This is shown in the table below.

Table 17 – Customer unit costs for Schedule 23 NEM and non-NEM customers based on NEM Breakout ACOS results. Assumes Schedule 23 NEM meters cost an average of $238/meter.

	SMALL COMMMERCIAL NON-NEM	SMALL COMMMERCIAL NEM
Services	$3.38	$4.54
Meters	$1.02	$1.63
Retail	$1.08	$4.17
TOTAL	$5.48	$10.33

Q. How did Schedule 23 service drop costs change for NEM and non-NEM customers?

A. The unit cost assumptions for Schedule 23 NEM and non-NEM customers were the same. However, the NEM class had a higher proportion of 3-phase services compared to the non-NEM class, as shown in the table below. This results in an increase of costs per customer in that class because 3-phase service drops cost more than 1-phase service drops.

used for Schedule 23 customers.

Table 18 – Percentage of Schedule 23 NEM and non-NEM customers by phase service type.

	Schedule 23 Non-NEM	Schedule 23 NEM
1-Phase	65.81%	11.80%
3-Phase	34.19%	88.20%

Q. How did Schedule 23 retail costs change for NEM and non-NEM customers?

A. As with residential NEM customers, Schedule 23 NEM retail costs were higher per customer due to direct cost assignments to NEM customers. These are shown in the table below.

Table 19 – Retail function costs assigned to Schedule 23 NEM customers.

	Schedule 23 NEM
Estimated Incremental Cost of Administration	$16,110
Application Fee Revenue	($7,404)
Estimated Incremental Cost of Customer Service Cost	$4,415
Total Incremental Cost of Administration & Customer Service	$13,120
Total Cost/Customer/Month	$3.35

Q. Based on these results are the differences in customer-related unit costs significant for NEM and non-NEM small commercial customers?

A. No. Metering costs may be higher, but changes in service drop costs are driven more by other characteristics of the customers, namely larger customer size and higher frequency of 3-phase service. Additional administrative costs for the NEM program—if assigned only to NEM customers—or increased transformer costs necessary to accommodate bidirectional flows are best recovered through an alternative charge such as an application fee or interconnection fee as discussed previously in this testimony.

Q. What recommendations do you make specifically regarding Schedule 23 NEM customers?

A. I recommend the Company clarify how the need to meter bidirectional flows would impact average per meter costs to serve Schedule 23 NEM customers compared to non-NEM customers.

IV. Summary Conclusions and Recommendations

Q. Please outline your conclusions and recommendations to the Commission.

A. Based on my analysis, I make the following conclusions and recommendations.

- Residential NEM customers do have a different load shape than non-NEM customers. More specifically, NEM customers exhibit the "duck curve" shape that has lower midday net consumption followed by a rapid rise in demand at sunset.
- Differences in load shape between residential NEM and non-NEM customers do not translate into large differences in annual load factors.
- There is more variation in the load factors of the residential NEM customers, but not drastically so.
- NEM and non-NEM residential customers have similar total unit costs.

- I do not recommend that transformer costs be included in the customer charge for residential customers. Although these costs may be fixed, that does not by itself justify their inclusion in the customer charge.
- If there is a need for transformer upgrades to interconnect a DG system, then the cost of the upgrade is best recovered from the connecting customer through an interconnection charge and not a monthly customer charge.
- The use of a 1NCP allocator for allocating transformer costs may double count customer loads for residential customers who switched to NEM service between July and December 2015.
- I recommend the Company ensure that the transformer allocator does not double count customers in its NCP calculation. This should reduce costs allocated to the NEM residential class for the NEM breakout ACOS study.
- NEM customers do require modestly higher metering costs, but that difference alone does not justify a higher customer charge.
- Changes in service drop costs between NEM and non-NEM residential customers are driven more by other characteristics of the customers, such as placement on the underground or overhead system.
- Based on my analysis and findings described above, it is not necessary, for now and at the current level of penetration, to separate NEM customers into their own class.

- Despite this, I do not object to the separation of NEM customers into a separate class if deemed appropriate for other policy reasons, or to address compensation rates for excess generation exported to the grid.
- Compensation for energy exports at retail rates is the primary driver of the low revenue parity ratio for residential NEM customers shown in the Company's NEM Breakout ACOS study.
- Traditional NEM excess energy compensation, at full retail rates, is not sustainable in the long-run with very high rates of DG penetration.
- All the incremental costs the Company considered for the NEM program, including administration costs, engineering costs, and integration costs appear reasonable.
- Since the Company is using a one-year historic test-period for its cost-benefit analyses as discussed from the Phase I Commission Order, it is likely that transmission, distribution, and environmental compliance avoided cost benefits may not be able to be properly captured. Evidence of such benefits might be presented by other parties in this docket and I will respond subsequently as appropriate.
- Avoided distribution costs would need to be analyzed over a longer period of time than one year and should also be analyzed for providing location-specific benefits when possible.
- Avoided transmission and avoided generation capacity benefits would need to be analyzed over a longer period of time than one-year.

- While the Company's method to calculate avoided line losses is a reasonable proxy, it could potentially under- or over-estimate actual line losses avoided.
- I would recommend that the Commission consider opening a separate docket to properly vet possible DG costs and benefits to RMP's distribution system, which could potentially include parties to the current docket and all stakeholders with an interest in DG, in order to determine the compensation rate.
- Demand charges have the potential to properly reflect cost causation on the distribution system, especially if they are based on coincident peak or are time-differentiated.
- Due to issues regarding the installation and cost of required metering capable of recording demands over all hours of the billing cycle, customer acceptance and understanding, ability to monitor and control electricity bills, and the potential for rate shock and dislocation, I recommend demand charges be implemented gradually, if they are part of the approved rate design.
- I recommend the Commission also consider alternative rate designs or other ratemaking tools to address problems with current rates.
- TOU or other time-differentiated energy charges may more closely align NEM rate design with cost causation principles, if metering can be implemented to measure customer imports and exports separately over all hours of the billing cycle, to reflect hourly and seasonal differences in wholesale power supply costs and the peak demand periods which T&D systems are built to meet.

- I support the consideration of both a demand charge schedule and TOU schedule to allow for customer choice, as noted in Division Witness Dr. Artie Powell's Direct Testimony.
- Data collection through a rate pilot program(s) could enable the Commission to make more informed decisions about different time-based rate structures going forward.
- Regardless of the ultimate rate design and rates approved by the Commission, the rate design and rates should be gradually implemented through steps that enable proper transition to bi-directional meters and avoid or mitigate adverse average rate and bill impacts for customers.
- By decreasing the NEM program cap to a level near the current program size or a near-term projection of size, the Commission can create a defensible class of NEM customers that might be gradually transitioned, while newcomers after the Commission's order in this proceeding might have a new regime immediately applied.
- I agree with the Company that there is a cost of interconnection incurred for both program administration and engineering review when a customer submits an interconnection application for any system, regardless of size. These costs should be borne only by the applicants, since non-NEM customers are not contributing to these costs.
- I recommend that interconnection costs vary based on whether the interconnecting DG system is expected to export power to the grid.

- My conclusions regarding the importance of correctly valuing exports, NEM costs and benefits, and the use of application fees and interconnection fees apply to both residential and commercial NEM customers.
- I recommend the Company clarify how the need to meter bidirectional flows would impact average per meter costs to serve Schedule 23 NEM customers compared to non-NEM customers.

Q. Does this conclude your testimony?

A. At this time, yes.