Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah St, Suite 2000, Portland, Oregon, 97232. My present position is Manager, Pricing and Cost of Service.

Qualifications

Q. Please describe your education and professional background.

A. I graduated magna cum laude from Oregon State University in 2004 with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for twelve years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over six years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. I assumed my present position in March 2016.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in California and Washington.

Summary

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support the Company's cost of service analyses that were prepared to comply with the Commission's order issued November 10, 2015, in Docket No. 14-035-114 in which the Commission established a framework for determining the costs and benefits of the net metering program ("November 2015 Order"). My testimony demonstrates that the Company's cost of service studies are accurate and reliable, and are consistent with Commission-approved standards that have been approved over the years,[1] and should be accepted by the Commission.

Q. Please summarize your testimony.

A. To comply with the November 2015 Order, the Company prepared two cost of service analyses: one that compares the costs and benefits of the net metering program by examining the difference with and without the existence of the net metering program, referred to in the order as the actual cost of service ("ACOS") and counterfactual cost of service ("CFCOS"); and another that examines the results of segregating net metering customers into separate classes in the class cost of service study, referred to by the Company as the net metering breakout cost of service ("NEM Breakout COS"). The results of both analyses demonstrate that, as the net metering program is currently structured, the costs of the program exceed its benefits. In particular, the revenue received from residential net metering customers is insufficient to cover their cost of service, which will shift costs onto other customers whose rates will ultimately increase.

[1]See *In the Matter of PacifiCorp's Financial Reports, 2016, Annual Cost of Service Study - 2015*, Docket No. 16-035-15 (in reviewing PacifiCorp's June 2016 Annual Cost of Service Study, the Commission stated, [b]ased on the Commission's review ... and the recommendation of the Division, the Commission acknowledges PacifiCorp's COS Study and Model.")

Cost of Service Analyses - Summary of Results

Q. What was the purpose of the Commission's November 2015 Order?

A. The Legislature enacted Utah Code § 54-15-105.1, which requires the Commission to perform the following two tasks:

(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.

Utah Code Ann. § 54-15-105.1 (hereinafter, § 54-15-105.1(1) will be referred to as "Subsection One" and § 54-15-105.1(2) as "Subsection Two"). The November 2015 Order established the appropriate structure for the Commission to perform the Subsection One analysis.

Counterfactual Cost of Service Compared to Actual Cost of Service

Q. What cost of service analysis did the Commission require in its November 2015 Order?

A. The Commission required the Company to show the cost of service at the system, state, and customer class levels by comparing an actual cost of service ("ACOS") study with a counterfactual cost of service ("CFCOS") study. The Commission directed the Company to "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."[2] Showing cost of service at the system, state, and customer class levels requires the use of the Company's jurisdictional allocation model ("JAM").

Q. How did the Company perform the cost of service analysis required by the November 2015 Order?

A. Using the 12-month historical period ended December 31, 2015, the results of a counterfactual JAM ("CFJAM") and a CFCOS were compared to the results of the actual JAM ("AJAM") and the ACOS Study. The AJAM is the model used to prepare the December 2015 results of operations, in Docket No. 16-035-15, but with a revision to the Utah customer count used in calculating the Customer Number ("CN") factor that was identified as a result of the Division of Public Utilities' ("DPU") review.[3] The ACOS study is the same as the 2015 Annual Cost of Service Study, which is based upon the December 2015 results of operations, but with minor changes made to incorporate the Commission's direction in their correspondence dated October 25, 2016, and using the AJAM.

The CFJAM assumes that the net metering program does not exist and relative to the AJAM, includes:

- Higher net power costs to supply the energy that would have been generated by net metering customers' private generation, as shown in Company

[2] November 2015 Order.
[3] The CN in the 2015 Results of Operations JAM inadvertently included a double count for the Company's Cool Keeper customers which resulted in overstating the number of billings. For further information, see the DPU's action request filed with the Commission on September 29, 2016.

witness Mr. Michael G. Wilding's testimony, which includes a description of how net power costs were estimated.

- Higher net power costs to account for line losses associated with delivering energy from more remote sources.
- Removal of bill credits related to private generation.
- Lower engineering and administrative costs required to interconnect net metering customers.
- Lower customer service and billing costs.
- Lower metering costs.
- Higher allocations of system costs to Utah to reflect higher demands and energy for the state.

Later in my testimony, I describe how the changes in bill credits, line losses, customer service and billing costs, administrative costs, engineering costs, and metering costs were developed.

The CFCOS uses the CFJAM and includes higher revenues, higher energy, and higher demands for each customer class with net metering customers. This includes residential service on Schedules 1, 2, and 3, Schedule 23, Schedule 6, Schedule 8, and Schedule 10. Later in my testimony I describe how the Company developed the change in energy and demand used in the CFCOS. To hold the rate of return constant between the CFCOS and the ACOS, a $2.0 million rate decrease is applied to the results of the CFCOS, which was calculated by comparing the difference in results between the CFJAM and AJAM.

Q. What are the results of the analysis?

A. Exhibit RMP___(RMM-1) shows the overall results of the Subsection One analysis ordered by the Commission. In this exhibit, the difference between the CFCOS and ACOS are shown at the system, state, and class levels. Positive values are net costs (increases in costs) and negative values are net benefits (decreases in costs).

Page 1 shows the difference between costs and benefits of the net metering program at the system level. For costs, values are shown for increased metering cost, increased engineering/administration costs, increased customer service/billing cost, and net metering bill credits. For benefits, the estimated impact of lower net power cost and value of avoided line losses are shown. Overall, the analysis shows a net cost to the system of the net metering program of $3.7 million or about $70.40 per megawatt hour (“MWh”).

Page 2 shows the difference between costs and benefits of the net metering program at the Utah state level. All of the costs and benefits from page 1 are included plus an additional benefit for lower interjurisdictional allocation to the state. At the state level, the analysis shows a net cost to Utah for the net metering program of $2.0 million or about $38.76 per MWh.

Page 3 shows the difference in costs and benefits of the net metering program at the customer class level. Each of the costs and benefits on page 3 are the same in total as those shown on page 2. An overwhelming majority of the net cost to Utah is attributable to residential net metering customers. At the customer class level, the analysis shows a net cost to residential customers for the net metering program of $1.7 million or about $58.60 per MWh. For Schedule 8, the analysis shows a slight net benefit of $0.16 million. For Schedules 23, 6, and 10, the analysis shows a net cost of $0.1 million, $0.02 million, and $0.01 million respectively. For other classes that do not participate in net metering, the analysis shows a $0.4 million net cost. Table 1 below summarizes the net cost or (benefit) of the net metering program at the system, state, and customer class levels.

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. How do the summary results from the ACOS study and the CFCOS study compare?

A. Exhibit RMP___(RMM-2) shows the summary of results from the ACOS study, the CFCOS study, and the difference between the two studies. It summarizes, both by customer group and function, the results of the class cost of service studies for the 12-months ended December 31, 2015. Page 1 of Exhibit RMP__(RMM-2) presents results for the ACOS study. Page 2 shows the results for the CFCOS study. Page 3 shows the difference in results between two studies.

Q. Previously you stated that the cost of service studies were performed consistent with Commission-approved standards. Please explain.

A. As required, the Company annually files a cost of service study, which is reviewed by the DPU and is available to any other interested party. The DPU makes a recommendation to the Commission based on the results of its review. The Company filed its cost of service study for the calendar year 2015 results in June 2016. On October 25, 2016, the Commission issued an acknowledgment letter stating, "[b]ased on the Commission's review of PacifiCorp's filing and the recommendation of the Division, the Commission acknowledges PacifiCorp's COS Study and Model. The Commission requests PacifiCorp evaluate the Division's and the Commission's observations and make appropriate changes to the COS model in future COS model filings."[4]

Q. Do the cost of service studies filed in this case include the changes the Commission requested be made to all future cost of service model filings?

A. Yes.

CFCOS Study Inputs - Load Changes

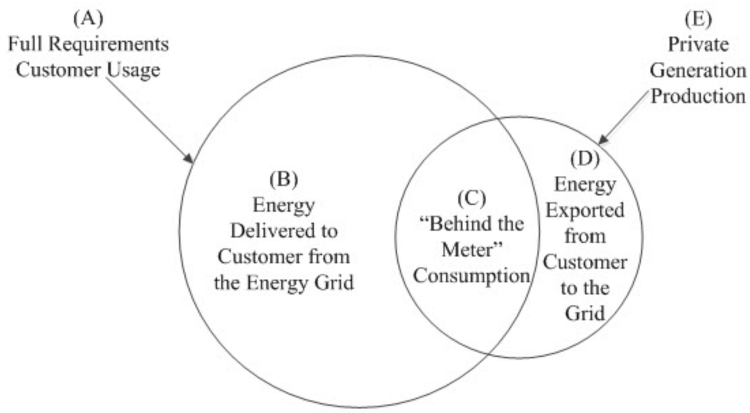
Q. In the CFCOS, how did the Company estimate the increase in energy consumption associated with the assumption of no private generation?

A. Estimating the increase in energy consumption and corresponding change in revenue for the CFCOS requires comparing the current level of energy and revenue that is billed to net metering customers with the level of energy and revenue assuming no private generation. The current net amount of energy usage and

[4] Supra, note 1.

associated net revenue that is billed to net metering customers is known and used in the ACOS. Estimating the level of energy and revenue without private generation requires estimating what the energy consumption would be for net metering customers if they were full requirements customers. Figure 1 illustrates how full requirements usage is determined for net metering customers.

Figure 1. Illustration of How Full Requirements Usage Can Be Determined



(B) and (D) are known

(E) can be estimated

(A) Full Requirements Usage = (B) + [(E) - (D)]

The bills for net metering customers are based upon the energy delivered to them from the energy grid, net of the energy exported from their private generation system to the grid. Both of these values, which are represented by (B) and (D) in Figure 1, are measured by a bi-directional meter. Private generation production, represented as (E) in Figure 1, is estimated by multiplying a standardized production profile by the nameplate capacity of each customer's generation system on a monthly basis. To develop full requirements energy usage, shown as (A) in Figure 1, the difference between (E) and (D) is added to (B). The total full requirements energy for net metering customers in the Residential and Schedules 23, 6, 8, and 10 classes was estimated by applying this calculation.

Q. How did the Company develop the standardized production profile?

A. By December 2014, the Company had installed 52 load research profile meters on residential customers with private generation systems. Of those 52 customers, the Company received permission to install 36 production profile meters that measure the generation from their private generation systems on a 15 minute-interval basis. The Company then converted the production profiles for each private generation system into a generic shape where the highest 15 minute reading was considered to have a value of one. The Company divided all other values by the highest reading such that each other period was a fraction of one. Establishing this generic shape allows the profile to be scalable by the installed capacity of private generation systems. The Company averaged the generic production shapes of all the private generation systems for each county, and established an overall standardized production shape for the state by weighting each county's generic profile by the overall nameplate installed private generation capacity in each county as of December 31, 2015.

Q. Did the Company benchmark the standardized production shape against any other outside data source?

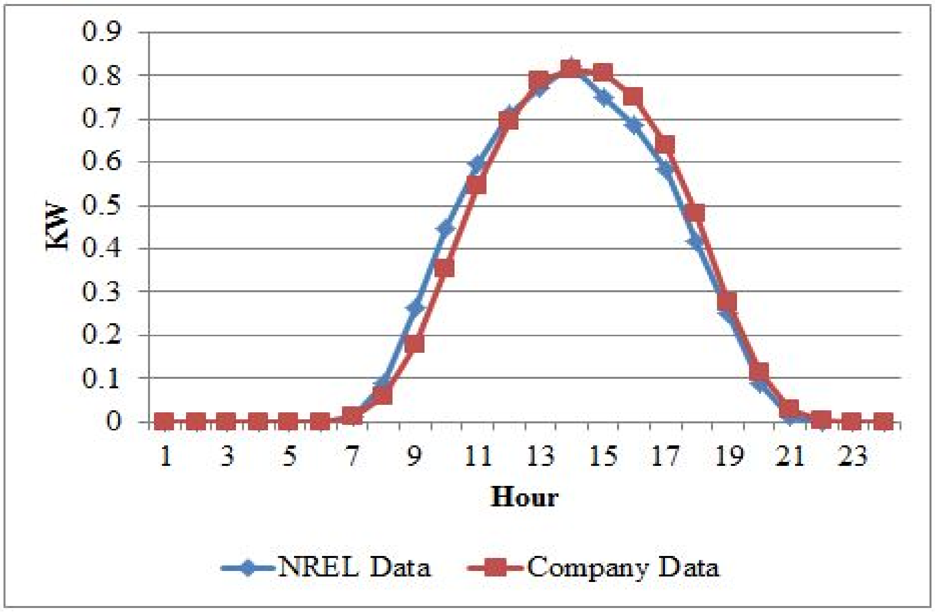
A. Yes. The Company compared the standardized production shape to hourly shapes from National Renewable Energy Laboratory's ("NREL") online PVWatts® calculator. The Company compared the two samples by performing a linear regression. A regression assesses whether the predictor variables (the Company's production shape) account for variability in a dependent variable (the PVWatts® production shape). The Company can measure how representative the sample data is to the PVWatts® data by treating the PVWatts® generation data as the dependent variable and the production sample data as the independent variable.

Based on the Company's findings, the regression has an Adjusted R-squared of 0.994 (a perfect correlation would be 1.0). This indicates that the model is a good predictor of the dependent variable. Further, the regression has a Durbin-Watson statistic of 2.082, signifying that autocorrelation has been corrected within the model (a value of 2.0 would indicate complete absence of autocorrelation). The regression coefficient and elasticity are 1.036 and 0.942 (again, a perfect correlation would be 1.0), respectively. This indicates the two sets of data behave similarly.

Further, the two independent samples are highly correlated with a correlation coefficient of 0.984. This demonstrates that the hourly shape of the NREL sample is similar to the shape of the standardized production profile. Exhibit RMP ___(RMM-3) provides a description of the Company's benchmarking to the NREL data analysis.

A visual comparison of the Company's production curve and the PVWatts® curve also demonstrates that both curves have a similar shape and behavior. Figure 2 below shows the average hourly solar production for the Company's estimate compared to the output from NREL data during the 2015 peak month of June:

Figure 2. June 2015 Average Hourly Solar Production from Company and NREL Data



Q. Please explain what Exhibit RMP___(RMM-4) shows.

A. Exhibit RMP___(RMM-4) shows how the difference in energy sales between the CFCOS and the ACOS studies is calculated. The billed energy for net metering customers during the period was 188,410 MWh. The full requirements energy usage for net metering customers is estimated to be 239,706 MWh. The overall difference between the CFCOS and ACOS energy sales is 51,297 MWh.

Q. Given the standardized production shape and the known nameplate capacity for customer private solar generation, what is the Company's estimate of private generation production?

A. The Company's estimate of private generation production for the period is 52,877 MWh and is shown on Exhibit RMP ___ (RMM-4).

Q. Why is the difference in energy sales between the CFCOS and the ACOS not the same as estimated private generation production?

A. While the difference in energy sales between the CFCOS and ACOS is close to the estimated private generation production (51,297 MWh versus 52,877 MWh), they are not the same. The difference is the result of net metering energy banking, which I discuss below. For residential and small non-residential net metering customers, if the energy exported from the customer to the energy grid is more than the energy delivered from the energy grid to the customer during the billing month, the Company credits a customer with a kilowatt-hour credit that is applied to future bills until the end of the net metering program year. In any given billing period, net metering customers may be making energy deposits or withdrawals into and out of their bank. The overall quantity of energy reflected in the ACOS represents billed energy which considers the impact of energy banking. The CFCOS contains the estimated energy for net metering customers assuming full requirements usage, which does not include any impact from banking.

Q. In the CFCOS, how did the Company estimate the increase in demand that would exist if there were no private generation?

A. The Company modified the hourly, Utah state border loads, and class loads that were used in the ACOS by the estimated private generation production profile that I described earlier in my testimony. For Utah border loads, this expansion by the estimated production profile is at the input level, accounting for line losses. The Company bases interjurisdictional allocations upon border loads that measure all load coming into a jurisdiction as well as all load flowing out of a jurisdiction. Since private generation production would stay within the state and would consequently reduce state load for interjurisdictional allocations, the allocation factors in the CFCOS were modified to reflect what allocation factors would have been, absent private generation. For the CFCOS, the Company expanded customer class loads by the full private generation production profile to be consistent with how loads were developed for the CFJAM.

Q. How did the Company determine and apply line losses to private generation for the CFCOS analysis?

A. To bring private generation to the input level, nameplate installed capacity was determined by month for customers served at the secondary voltage level and the primary voltage level. The Company then expanded private generation by class by the loss factor used in the recently acknowledged 2015 cost of service study for these quantities of nameplate capacity. Bringing private generation to the input level, increases it from 52,877 MWh to 57,784 MWh. The estimated change in net power cost between the ACOS and CFCOS described in Mr. Wilding's testimony reflects private generation at the input level.

CFCOS Study Inputs - Bill Credits

Q. How did you calculate the removal of bill credits for the CFCOS?

A. The Company segmented the change in energy between actual billed energy and full requirements energy into energy blocks by season (Summer and Winter) and by on-peak and off-peak periods, as applicable. The Company then estimated the removal of bill credits (revenue difference between actual billed revenue and full requirements revenue) by multiplying the changes in energy by the corresponding energy charges. For residential net metering customers, the Company estimated full requirements energy for each monthly bill to determine the levels of energy consumption that would occur in the different tier block usage levels that apply to residential energy charges. The Company then applied the change in the proportion of energy in each tier block energy charge to the overall estimated change in energy to estimate bill credits for the residential class.

Exhibit RMP___(RMM-5) shows bill credits related to the net metering program (the estimated difference in revenue between the CFCOS and ACOS) by rate schedule. This exhibit demonstrates overall bill credits associated with the net metering program of approximately $4.2 million.

CFCOS Study Inputs - Customer Service and Billing Costs

Q. How did the Company develop net metering customer service and billing costs?

A. The Company sorted customer service and billing costs related to the net metering program into three categories:

1. Phone calls, including customer inquiries and requests related to the net metering program.
2. Initial setup, including requests for a meter exchange and setting up customers on the net metering program in the Company's billing system.
3. Ongoing support, including back office work necessary to correctly bill customers participating in the net metering program.

Developing the costs related to each of these areas required obtaining estimates from Company personnel involved in the day-to-day operations at the call centers regarding the total time spent on each of these activities. Those figures were then multiplied by the fully-loaded hourly cost for a call center agent.

To determine the proportions of these costs that are related to the different customer classes, the overall cost estimates for each activity were spread based upon an appropriate driver for those costs. Since phone calls were primarily for customers who were considering participation in the net metering program, this cost was allocated on the number of applications in the period. Initial setup cost was allocated based upon the number of interconnections during the period. Since ongoing support is related to the number of bills, this cost was allocated by the average bills during the period. Exhibit RMP___(RMM-6) shows the customer service and billing costs related to the net metering program by customer class.

CFCOS Study Inputs - Program Administration

Q. How did the Company develop net metering program administrative costs?

A. The Company dedicates a department to the administration of the various net metering programs it oversees and implements across the six states that it serves. This includes the handling and processing of interconnection applications. The overall expense of this department was multiplied by the proportion of workload dedicated to the net metering program in Utah. This expense was reduced by the application fees that were collected in 2015 for larger non-residential interconnections. Page 1 in Exhibit RMP___(RMM-7) to my testimony shows net administrative expense related to the net metering program by customer class. Pages 2 and 3 of Exhibit RMP___(RMM-7) show how the Company determined administrative expense by state and rate schedule.

Q. How did the Company develop engineering costs related to the net metering program?

A. Engineers review the technical details of the interconnection applications to ensure that private generation systems can safely and reliably interconnect to the Company's distribution system. To develop the engineering costs related to the net metering program, the estimated time it takes to review an application was multiplied by the fully-loaded hourly cost of a field engineer which was then multiplied by the number of applications in 2015. The estimated time for review for each application varied by rate schedule to reflect differences in the complexity of review. Exhibit RMP___(RMM-8) to my testimony shows engineering expense related to the net metering program by customer class.

CFCOS Study Inputs - Meter Costs

Q. How did the Company develop the change in metering costs associated with the net metering program?

A. To accurately bill net metering customers, the bi-directional flow of energy must be measured. The Company estimated the costs to replace and reprogram meters accordingly. Pages 1 and 2 of Exhibit RMP___(RMM-9) show the costs of metering related to the net metering program by customer class. Page 3 of Exhibit RMP___(RMM-9) shows the calculation of meter depreciation and deferred tax impacts.

CFCOS Study - Results

Q. What is the overall conclusion you draw from the comparison between the CFCOS and the ACOS?

A. The analysis shows that the costs that the Company or other customers incur from the net metering program do in fact exceed the benefits of that program, which will result in higher rates for other customers.

Q. What conclusions can you make from the difference in results by customer class in the analysis comparing the CFCOS to the ACOS?

A. Most of the net cost of the net metering program is attributable to the residential class. For all other customer classes, except Schedule 8, the net metering program is also a net cost. The net benefit shown for Schedule 8 is only $0.16 million or about 8 percent of the overall $2.0 million net cost for Utah. The results for Schedule 8 are primarily related to the low average cost of bill credits for these customers which reflects the Company's conservative assumption not to estimate any change in demand charges.

Actual Cost of Service with Net Metering Separately Broken Out

Q. Along with a comparison of the CFCOS and the ACOS, what other cost of service analysis did the Commission require in its November 2015 Order?

A. The Commission also required the Company to prepare a cost of service study under which the Company “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."[5]

Q. How did the Company prepare the NEM Breakout COS?

A. Starting with the class ACOS study, separate classes were created for the residential class and Schedules 23, 6, 8, and 10 net metering customers ("NEM classes"). For these different NEM classes, the characteristics of their cost of service were identified, removed from the overall class from which they were separated, and applied to the NEM classes. The characteristics for the NEM classes 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.

NEM Breakout COS - Demands

Q. How did the Company develop demand values for the NEM classes?

A. For the residential net metering class, demand values were based upon the load research study previously discussed. Each of these load research meters measured delivered and exported energy on a 15-minute-interval basis. The overall profile from these load research meters was scaled to the delivered and exported energy volumes on a monthly basis. The Company developed various monthly system coincident and distribution coincident peaks from this profile. The Company determined non-coincident peak on a monthly basis by averaging the non-coincident peaks for each of the sample profile meters and scaling by the overall number of customers in the population.

[5] November 2015 Order.

System coincident peaks and distribution coincident peaks were based upon energy deliveries to the customer. Non-coincident peak was based upon the maximum of either energy delivery or energy export. The Company allocates line transformers and secondary lines based upon each class's annual maximum non-coincident peak which is then weighted by a coincidence factor. Using the maximum of either delivered or exported non-coincident peak for each customer accurately reflects those customers' usage of these localized facilities, which are typically used by a small number of customers and must be sized to meet the demands imposed upon the equipment in either direction.

For the Schedules 23, 6, and 10 net metering classes, the standard profile that was developed for the ACOS study for their whole class, which includes both net metering and non-net metering customers, was adjusted to the overall energy volume for estimated full requirements usage of the net metering customers on a monthly basis to create full requirements profiles. Their estimated private generation production profile was then overlaid on top of that estimated full requirements profile to estimate delivered and exported energy on an hourly basis. For Schedule 8, demand values are based upon the readings from profile meters that are installed for all customers of this size.

Q. How did the Company first develop the sample of residential net metering customers?

A. Exhibit RMP___(RMM-10) explains the process by which the Company selected sample meters for inclusion into the load research study. Basically, meters were selected based upon their net energy usage reported from the billing system.

Q. Did the Company use all sample meters from the study's original design to develop loads for the NEM Breakout COS?

A. No. Sixty-two (62) meters were initially included in the study. Since ten of the original meters were for customers with wind-based private generation and 99 percent of all private generation capacity is solar, the Company used the data from the 52 meters for customers with solar-based private generation to develop loads for the NEM Breakout COS.

Q. Were the strata breakpoints and weightings discussed in Exhibit RMP___(RMM-10) the same as those ultimately used to develop loads for the NEM Breakout COS?

A. No. The strata breakpoints discussed in Exhibit RMP___(RMM-10) were based upon the billed or net energy of the total population of residential net metering customers at the time the sample was designed. To develop loads for the NEM Breakout COS, the Company used delivered energy to inform the 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.

NEM Breakout COS - Direct Assignments and Energy

Q. What other important differences did the Company incorporate into the NEM Breakout COS for the NEM Classes?

A. While developing the CFCOS study, the Company identified engineering, administration, and customer service/billing related costs that are directly attributable to serving and interconnecting net metering customers. These costs which are shown on Exhibit RMP___(RMM-6), Exhibit RMP___(RMM-7), and Exhibit RMP___(RMM-8) were directly assigned to the different NEM classes. Also NEM classes are allocated energy-related costs for the energy that is delivered to them and receive credit to their cost of service for the excess generation that they deliver to the Company.

Q. Why does the Company allocate to net metering customers energy-related costs based upon their delivered energy instead of their net energy?

A. Net metering customers use the system in a way that is fundamentally different than other customers. Unlike other customers who consume only energy that is delivered to them from the energy grid, net metering customers may at different times be receiving energy from the energy grid, consuming their own private generation onsite, or exporting the excess energy from their private generation to the energy grid. Like with any other customer, the Company allocates its costs based upon the volumes of energy and the magnitude of demands the Company delivers to net metering customers. Inasmuch as net metering customers consume their own private generation onsite, the profile and overall quantity of energy delivered to them is reduced and the allocation of costs is also consequently reduced. The concept of net energy is a billing construct that is used for net metering. Net energy does not reflect a net metering customer's physical time-based relationship with the energy grid. Even though a net metering customer may produce as much total energy as that customer consumes over a period of time, in real time that customer still relies upon the energy grid to both import and export energy. The NEM

Breakout COS study appropriately assigns costs to net metering customers based upon their usage of the Company’s system.

Q. Please describe how net metering customers receive credit for their excess energy in the NEM Breakout COS study.

A. For the energy that net metering customers export to the energy grid from their private generation systems, a credit for their exported energy is assigned to them based upon the difference in monthly net power cost associated with private generation that was calculated for the CFCOS analysis. Company witness Mr. Wilding’s testimony provides a description of the net power cost analysis. The Company increases the credits applied for exported energy to reflect avoided line losses. The overall annual excess credit also considers each NEM class’s impact from energy banking. For energy deposits into customers' net metering bank, the excess energy credits are reduced. For energy withdrawal from customers' net metering bank, excess energy credits are increased. Exhibit RMP___(RMM-11) includes the calculation of excess energy credits for each NEM class. In total the value of the energy credits for all NEM classes is $553,067.

Q. Why does the Company adjust excess energy credits to account for the impact of net metering banking?

A. In a class cost of service study, the ultimate result of the study is a comparison of whether the revenues provided from each class are less than, more than, or equal to each class’s cost of service. Within the annual period that is used for a cost of service study, revenue from net metering customers is based upon billed energy that includes some out-of-period impact from net metering energy banking. For example, in the 12 months ended December 31, 2015, some energy credits from excess energy banked in 2014 are applied to bills that occur in 2015. Conversely, some excess energy that is banked in 2015 will be applied to bills in 2016. Ignoring the effect of net metering energy banking would create a mismatch between revenues and cost of service. Subtracting 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.

Q. Please describe how the Company applies excess energy credits to the cost of service of the NEM classes.

A. The Company directly assigns excess credits to each NEM class. It allocates an offsetting cost for the excess credits to all classes based upon Factor 30 - Energy. Both the excess credits and the offsetting costs are functionalized to the Production function.

Q. Why is there an offsetting cost for the excess credits?

A. To balance out the credits directly assigned to net metering customers in the cost of service model, it was necessary to include a cost that offsets that credit. The excess credits in the NEM Breakout COS reflect a fair value of the energy that net metering customers export to the energy grid for other customers to use. All customers, including net metering customers, benefit from this excess generation in the form of reduced net power cost. It is reasonable that all customers receive an increased allocation of cost proportional to that benefit to offset the value assigned to the NEM classes for their exported energy. With this treatment of excess energy, customers are economically indifferent between whether they receive a kilowatt hour from a private generation system or from some other source.

Q. Why does the Company allocate the offsetting cost for the excess credits on the basis of energy?

A. The offsetting cost of the excess energy credits is allocated on energy because the majority of net power costs including fuel are allocated on the basis of energy.

Q. Why does the Company allocate the offsetting cost for excess credits to NEM classes as well as to the other non-net metering classes?

A. Private generation that is exported to the energy grid may be consumed by both customers who do not participate in net metering as well as those who do. Also net power costs in total are reduced as a result of exported private generation. It is reasonable to assign some of the offsetting cost of excess energy to net metering customers in proportion to the energy that is delivered to them.

NEM Breakout COS - Results

Q. Are there any challenges with the NEM Breakout COS study?

A. Yes. While the Company has a load research study for residential net metering with a full year of profile data, the Company does not have the same information for Schedules 6, 10, and 23 net metering customers.

Q. Why did the Company create segregated NEM classes for Schedules 6, 10, and 23 in the NEM Breakout COS study if load research studies were not available?

A. The Company prepared this information to comply with the November 2015 Order. The information for Schedules 6, 10, and 23 net metering customers attempts to show an estimate of their cost of service with separate class treatment and provides some context regarding the general magnitude of cost shifting that may exist for these customers.

Q. Please identify and explain Exhibit RMP___(RMM-12).

A. Exhibit RMP___(RMM-12) shows the summary of results from the NEM Breakout COS study in the same format as the studies that are presented in Exhibit RMP___(RMM-2), but with results shown for the NEM classes. Exhibit RMP___(RMM-12) shows that residential net metering customers and Schedules 6, 8, 10 and 23 net metering customers require a 65.05 percent, -8.43 percent, -8.30 percent, 11.42 percent, and 8.42 percent change to present revenues, respectively.

Q. Please identify and explain Exhibit RMP___(RMM-13).

A. Exhibit RMP___(RMM-13) shows the difference in cost of service results for each class between the NEM Breakout COS and the ACOS. This satisfies the November 2015 Order's requirement for the Company to "show the impact their segregation has on the class in which they would otherwise participate."[6] Exhibit RMP___(RMM-13) indicates that the costs for the residential class would be reduced by $1.1 million if net metering customers were excluded from their class, whereas the costs for Schedules 6, 8, and 10 customers would increase by $0.3 million, $0.2 million, and $0.04 million, respectively.

[6] *Id.*

Q. Do the results of the NEM Breakout COS study mean that the net metering program as currently structured is a significant benefit for Schedules 6, 8, and 10?

A. No, not necessarily. The analysis shows how the cost of service results vary for specific groups of net metering customers relative to other customers within the same class. For Schedules 6, 8, and 10, the seemingly favorable results may not be so much an indication of the benefit (or cost savings) related to the net metering program as it may be an indication of the characteristics of net metering customers. As a percentage of their overall full requirements energy usage, private generation production for customers on Schedules 6, 8, and 10 is quite small relative to the residential and Schedule 23 classes. See Table 2 below:

Table 2. Private Generation Relative to Full Requirements Usage

NEM Class	Full Requirements Energy Usage (MWh)	Estimated Private Generation Production (MWh)	Private Generation Relative to Full Requirements Energy Usage (%)
Residential Net Metering	51,468	28,304	55%
Schedule 23 Net Metering	9,971	6,012	60%
Schedule 6 Net Metering	98,655	12,342	13%
Schedule 8 Net Metering	77,889	5,736	7%
Schedule 10 Net Metering	1,724	484	28%

Q. What is the overall conclusion that you draw from the results of the NEM Breakout COS?

A. The cost of serving residential net metering customers is significantly different than the cost of serving other residential customers. On a percentage basis, the revenue collected from residential net metering customers is vastly insufficient to cover the costs of serving them.

While the results for other non-residential classes are different between the classes with and without net metering, those differences are far less striking than the clear contrast for residential customers. An examination of parity ratios, which is the percentage of revenue relative to cost of service, reveals that revenues collected from non-residential net metering rate schedules are within a reasonable range (approximately 90 - 110 percent), but revenues collected from the residential net metering schedule are quite far off from parity with cost of service (approximately 60 percent). Table 3 below shows the parity ratios for all rate schedules which have net metering customers for the actual cost of service, both with net metering included and broken out separately.

Table 3. 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%

Q. How do the results for residential customers from the comparison between the CFCOS and the ACOS compare to the results for the NEM Breakout COS?

A. Both analyses demonstrate a similar result for residential net metering customers. As shown on Exhibit RMP___(RMM-1), the analysis which compares the CFCOS to the ACOS shows that the cost to the residential class of the net metering program is $1.7 million. The NEM Breakout COS results in Exhibit RMP___(RMM-12) show that the residential net metering class requires a $1.8 million increase to present revenues in order for the class to earn the jurisdictional average rate of return.

Adjusting the NEM Breakout COS Results to the Same Basis as the Last General Rate Case

Q. Upon what level of revenue requirement is it appropriate to design rates for residential net metering?

A. Company witness Ms. Joelle R. Steward's testimony describes the Company's proposed rate design for new residential net metering customers who submit net metering applications after December 9, 2016. The revenue requirement upon which those rates are designed is the same as the revenue requirement for the residential net metering class in the NEM Breakout COS, but adjusted downward to the same level of costs that were in Docket No. 13-035-184, the last general rate case ("2014 GRC"). While the analysis comparing the CFCOS to the ACOS provides useful information regarding the costs and benefits of the net metering program, the NEM Breakout COS provides a more specific examination of the level of revenue required to bring residential net metering customers to full cost of service. Adjusting the NEM Breakout COS results for the residential net metering class to the level used in the 2014 GRC ensures that rates for this class are set upon the same basis as for all other customers.

Q. How was the revenue requirement from the NEM Breakout COS adjusted to the same level of costs in the 2014 GRC?

A. Exhibit RMP___(RMM-14) shows how the NEM Breakout COS results for the residential net metering class were adjusted to the level of costs from the 2014 GRC. The class cost of service study that was filed in the 2014 GRC was modified so that the overall cost of service for the residential class was adjusted to the step 2 revenue of $684,856,226[7]. Column A in Exhibit RMP___(RMM-14) shows the unit costs for the residential class from this study. Column B in Exhibit RMP___(RMM-14) shows the unit costs for "other" residential customers from the NEM Breakout COS. Column C in Exhibit RMP___(RMM-14) shows the unit costs for residential net metering customers from the NEM Breakout COS. Column D in Exhibit RMP___(RMM-14) shows the proportion of residential net metering revenue requirement to overall residential revenue requirement from the NEM Breakout COS for each sub-functional cost category. Sub-functional cost categories within the units costs of the cost of service study include Production-Demand, Production-Energy, Transmission-Demand, Transmission-Energy, Distribution-Substations, Distribution - Poles and Conductor, Distribution - Services, Distribution - Meter, Retail, and Miscellaneous. Column E in Exhibit RMP___(RMM-14) shows the application of the proportions in Column D to the overall residential revenue requirement from the 2014 GRC in Column A by each sub-functional cost category and adds each of the costs for those categories. Exhibit RMP___(RMM-14) shows a total of $4,210,660 for the total in Column E, which represents an eight percent reduction in the revenue requirement for the residential net metering class relative to the results from the NEM Breakout COS.

[7] The step 2 price change became effective September 1, 2015 and reflects the currently effective base revenues for the Company.

Conclusion

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission issue an order finding that the results of both of the analyses that I presented are accurate, reliable and are consistent with the November 2015 Order.

Q. Does this conclude your direct testimony?

A. Yes.