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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

PRE-FILED DIRECT TESTIMONY OF RICHARD COLLINS ON BEHALF OF VIVINT SOLAR, INC.

Submitted on behalf of Vivint Solar, Inc.

/s/Stephen F. Mecham

Q. Please state your name and occupation.

A. My name is Richard S. Collins. I am a Professor of Economics and Finance at Westminster College located at 1840 South 1300 East, Salt Lake City, UT 84108.

Q. On whose behalf are you filing testimony in this Docket?

A. I am testifying on behalf of the Vivint Solar, Inc., a residential solar company headquartered in Utah with operations throughout the United States.

Q. Have you submitted testimony to this Commission before?

A. Yes. I submitted testimony in Docket Nos.03-035-14, 05-035-08, 05-035-09, 06-035-41 and 06-035-76, 07-035-93 and 08-035-38 and 09-035-23.

Q. Do you have experience in utility regulatory matters?

A. Yes. Prior to my employment at Westminster College, I worked for the Public Service Commission of Utah ("***Commission***") for approximately thirteen (13) years.

Q. Please describe some of your responsibilities at the Commission.

A. I provided technical advice to the Commission on rate proceedings and a variety of other issues. I was responsible for tracking PacifiCorp's IRP planning process, avoided cost, demand-side management, cost of capital, and deregulation issues. In addition, I helped write orders and wrote or coauthored a series of technical reports on deregulation issues for the Commission and the legislature.

<u>SUMMARY OF TESTIMONY</u>

Q: What is the purpose of your testimony in this docket?

A: I will attempt to provide a broader construct in which the Commission can evaluate the intricacies of the multiple issues in this case and be consistent with the Commission's overall objective. The Commission's November 10, 2015 Order in this docket provides a framework in which to evaluate the costs and benefits of the net metering program. The aim of this analysis is to provide guidance for any improvements and changes in the program to insure equity amongst and between rate classes. The Commission must balance a number of different policy objectives: the promotion of distributive generation through net metering as outlined in Utah House Bill 256, as well as insuring equity amongst ratepayers as directed in Utah Statute 54-15-105.1 and 105.2.

Q: What should the goal of the Commission be in this proceeding?

The Commission's statutory mandate is to promote the public interest through its regulation of Rocky Mountain Power ("***RMP***"), a utility regarded as a natural monopoly. One of the primary regulatory objectives of the Commission is to insure quality service to the ratepayers at a reasonable rate while providing the utility the opportunity to earn a fair and reasonable return on its investment, so as to keep the utility financially healthy. A financially healthy utility is better able to provide reliable service to its customers. The Commission should also encourage a diversity of generation resources in order to protect the ratepayers from future risks that may adversely affect a particular generation source. It should take this mandate to promote the public interest both seriously and broadly. This means that the Commission must look at what is best for the ratepayers as a whole while maintaining its commitment to allow RMP the opportunity to earn a fair and reasonable return.

Q: Why is this such a difficult case for the Commission?

A: This case will require the Commission to be Solomon-like in its decision-making. The adoption of RMP proposed study and rate design will cripple the solar industry in Utah to the detriment of Utah citizens and RMP ratepayers. However, an overly generous tariff to the net metered customer could harm other residential customers. The Commission should strive for an outcome that is fair to all sides and is flexible enough so that changes can be made to incorporate future events that affect both the costs and benefits of distributive generation.

Q: What specifically are you recommending?

I recommend that the Commission reject the results of RMP's cost of service study due to a number of critical errors and faulty assumptions made in their Actual Cost of Service (ACOS) and Counterfactual Cost of Service Studies, (CFCOS). There are similar issues with the NEM Breakout analysis. The Commission should either require that RMP resubmit its analysis with the necessary corrections or the Commission should adopt the recommendations for revisions of the tariff as contained in Dan Black's and Thomas Plagemann's testimony.

Q: What are the problems with RMP's analysis?

A: RMP has overestimated the costs associated with the net metering program and underestimated its benefits. There are major problems with RMP load study and its estimation of the production of net metered customers. The output of the net metered generation study is the key input into the Grid Model which estimates changes in net power costs; it is also an input into the calculation of the bill credits. The Commission should also reject RMP's NEM breakout study and RMP's contention that the Net Metered customers need a separate tariff and be segregated into a separate rate class. They should also find that the proposed three-part tariff is unnecessary and overly detrimental to new net metered customers.

This testimony will review RMP's Compliance Filing and the accompanying testimony.

I will point out a number of faulty assumptions and inconsistencies in the analysis. My testimony will also review and critique the Commission's order of November 15, 2016 which sets up the analytical framework for the analysis ordered in Utah Code Section 54-15-105.1 and the associated rates in 54-15-105.2. Because the Commission's required analytical framework fails to take into account the long-term benefits of a net metering program, it does not implement the Legislature's intent. For that, the Commission must require that long-term benefits of the metering program be included in RMP's analysis. The Commission should take this into account when rendering its final decision on the benefits and costs of the net metering program.

BACKGROUND

Q: Can you give a brief background on the main issues that pertain to this proceeding?

A: The electric utility industry is currently experiencing a new phenomenon of customer generated power that lowers the utility's load and provides a new source of energy for the utility. This presents a dilemma for the utility in that the distributed generation competes directly against its own generation and reduces the energy purchased by a residential solar ratepayer from RMP, due to the amount of energy consumed onsite behind RMP's meter. If the utility is under a cost of service regulatory regime, distributive generation will ultimately lower the utility's rate base and thereby lower its overall profits. This goes against the primary goal of a corporation which has a responsibility to maximize its profits and the return to its shareholders. However, as a regulated utility RMP is granted a monopoly franchise in return for providing service to all customers in its service territory, under Commission approved tariffs. Given RMP's monopoly status, the Commission's function is to insure that the utility is financially stable so it can provide reliable service to its customers at a reasonable rate for all ratepayers. The Commission is under no obligation to insure that the utility meets its ultimate goal of maximizing its profits and shareholders' wealth. The Commission is only obligated to provide the utility the opportunity to earn a fair and reasonable return on its investment and keep ratepayers' rates as low as possible given the fair and reasonable return constraint. This is a key distinction: opportunity for a fair and reasonable return on investment versus maximizing profits. To maximize profits the utility will need to increase its capital investment or rate base. Distributive generation represents competition to the utility and thus the utility will fight tooth and nail to eliminate competition as it presents a roadblock to its ultimate internal goal to increase profits and shareholder value. The Commission should recognize this motive as it evaluates the testimony and should remember that it is not the Commission's duty to protect or promote a utility's future rate base, but to provide the opportunity for the utility to earn a fair and reasonable return on its rate base, whatever that level may be.

Q: Do you have any evidence to support this hypothesis of anti-competitive behavior of a regulated utility?

A: This reaction of regulated utilities is well known and utilities across the nation have taken steps to stymie any competition whether it is distributive generation not owned by RMP, or qualifying facilities (QFs), or Independent Power Producers (IPPs). The trade press has made numerous comments on Berkshire Hathaway's resistance to net metering throughout its footprint, as discussed in more detail in Mr. Plagemann's testimony.

Q: What is the Commission's role in this proceeding?

A: The Commission, based on the evidence on the record, will need to decide whether to change the net metering program and, in making that determination, it must look at all of the benefits and the costs, both long-term and short-term, of the program and determine whether other customers are actually harmed under the program's current configuration and the degree of harm if any, that occurs. I believe that the burden of proof for showing that the current net metering tariff causes harm lies solely with RMP. Its case must show that the detrimental impacts of the current program are large enough to warrant a change in the current program and its tariffs. The Commission should also qualify its decision on the appropriate analytical framework and acknowledge that all of the benefits and costs of distributed generation in the long-term are not included in RMP's analysis. The statute is silent on the time frame for analyzing benefits and costs; it is the Commission who decided to limit the analysis to short run costs and benefits. The Statute states "The governing authority shall: (1) determine after appropriate notice and opportunity for public comment, whether the cost 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. The Commission's decision to use a cost of service analysis to determine costs and benefits as a way to establish rates makes sense only from a strictly administrative perspective, but the Commission should take into consideration in determining a just and reasonable charge, credit or ratemaking structure the long-term costs and benefits of the program. Limiting the cost and benefit analysis to a short-term, 12-month, test period creates a false and inaccurate view of rooftop solar and the impacts it has on RMP's grid and the ratepayers as a whole.

Q: Could you provide some background on cost of service and rate design?

A: The primary objective of a cost of service analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. A cost of service study analysis can provide a useful guideline for assigning cost responsibility to each customer classification in a way that avoids unjustifiable price discrimination. A cost of service analysis also provides information useful for designing individual rate schedules and provides support for justifying rate differentials to retail customers. The Commission directed RMP to use a cost of service study as the analytical framework for determining the benefits and costs of the net metering program and to determine an appropriate rate structure for net metered customers.

Q: What are the fundamental considerations that the Commission should take into account when designing rate structure?

A: James Bonbright, utility ratemaking expert, outlines in relative order of importance the basic criteria for ratemaking as listed below.

Table 1: Bonbright's Criteria for Ratemaking
1. Does the rate provide adequate revenue recovery to the utility?
2. Does the rate promote fairness in cost allocation (equity between customer classes)?
3. Does the rate promote efficient resource use?
4. Is the rate practical to implement (understanding, acceptance)?
5. Is the rate easy to interpret (noncontroversial)?
6. Does the rate provide revenue stability for the utility?
7. Does the rate provide bill stability for customers?

8. Does the rate avoid undue discrimination among customers?

Bonbright's criteria for rate design are just as relevant today as when he first wrote them.[1]

Q: Please explain the how the net metering tariff performs under the first two criteria of revenue adequacy and fairness between rate classes.

A: The establishment of a new rate class for Net Metering customers will not have a major impact on RMP's ability to collect its revenue requirement. As of this date, less than two (2) percent of the residential rate class have distributive generation and the allegation that this small group of ratepayers is not covering its full costs, even if true, does not materially affect the RMP's ability to earn its authorized rate of return, especially in light of the increased growth of the residential rate class as a whole. In fact, using RMP's numbers from its Filing, we see that a residential net metering customer covers approximately 92% of its total cost of service (which is low due to the limited 12-month view of benefits) and yet RMP is seeking to obtain an additional $20 per month for each residential net metering customer. There is no reason to redesign rates based on Bonbright's number one criterion because RMP's ability to obtain revenue recovery is not impacted by residential net metering customers. The second criterion requires the promotion of equity between classes. The majority of the net metering program's activity occurs within the residential rate class. Given the small number of residential net metered customers even if net metered customers are only covering 92% of their cost of service it would not affect other classes, rather it would primarily impact currently embedded equity and subsidies that currently exists within the residential rate class. For

1 See *Principles of Public Utility Rates* by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen (Hardcover - Mar 1, 1988).

example, according to RMP's Filing an average residential customers, with an average load, will pay approximately $999 per year for their service.[2] If rates are set to recover revenue requirement for the average ratepayer, with an average load, then those customers that consume less are not paying the full fixed costs of their usage and those that consume more than the average are paying more than their share of the fixed costs. In other words, low energy users are being subsidized by high energy users. Therefore, it is our conclusion that the current residential net metering tariff and its current rate design meets or surpasses the two most important criteria outlined by Bonbright. The Commission should recognize the current subsidies that exist in the residential rate class in a general rate class when it addresses the perceived and unconfirmed subsidies potentially going to the residential net metered customers.

Q: What about the third criterion, efficient use of resources?

A: Concerning the efficient use of resources; the Company's proposed three-part tariff would effectively destroy the solar industry in Utah, kill thousands of jobs, and impact economic growth with the state. A discussed in Mr. Plagemann's testimony, the Utah Public Service Commission should take note of what happened in Nevada. In that state, the Nevada Public Utilities Commission revised it net metering tariff at NV Energy's request. After more than a year of political, public, and regulatory turmoil, the Nevada Legislature took action to correct the Commission's error. In addition, RMP's 2015 IRP, the only one that has been reviewed and acknowledged by the Commission shows that when long-term benefits of net metering are included, the Present Value of Revenue

2 From data taken from RMM-12 page 1 and RMM-14 page 1 Residential cost from NEM Breakout (non-NEM) = $749,206,727 and number of non-NEM residential customers = 749,673 thus $749206,727 / 749,673 = $999.45 revenue per non-NEM customer.

Requirement (PVRR) is $706 Million dollars less when the high adoption of solar panels scenario (case S-05) is compared to the base case (CO5-1).[3] Those benefits averaged over the twenty (20) year planning horizon translate into $35 million dollars of benefit to the ratepayer each year. To adopt a new rate structure that would eliminate these benefits would violate the criterion of efficiently utilizing resources. The Commission should take note that in 2015 RMP found a net benefit for residential solar and RMP is now claiming a net cost, included abandoned revenue resulting from onsite behind the meter consumption. The Commission must keep RMP out of the residential ratepayer's home and ensures a customer's actions taken behind the meter stay untouched and unrestricted.

Q: How does RMP's rate design score under the other criteria of interpretation, understanding and implementation?

A: The Company's proposed three-part rate does not support the criteria of easy interpretation and implementation. This rate will not be practical to implement because the demand charge is difficult to understand and residential customers will not likely accept such a charge. Traditionally applied to commercial and industrial customers, demand charges calculate a fee for utility customers based on their peak consumption each month, usually measured hourly. Since demand charges tend to account for a hefty portion of a customer's bill, they could provide an incentive for reducing peak usage. Unfortunately, residential customers have few options to minimize demand, largely because such customers have little to no visibility into their kilowatt usage in any given hourly period. Not only do they lack visibility, residential customers lack the sophistication, resources, and technology to adjust time-based demand habits in any

3 See page 216 and 217 In the 2015 Integrated Resource Plan Volume II Appendices

meaningful.

Tariffs with a demand charge are difficult for residential customers to interpret as they better understand the concept of energy as measured in kilowatt-hour. Demand measured in kilowatts represents the capacity to produce energy, a much more difficult concept to interpret and understand.

Q: What about the criteria of revenue and rate stability?

A: With regard to providing revenue stability to the utility, this rate structure might keep revenue stable in the short run, as customers may not be able to reduce their demand charges easily. However, in the long run, the demand charge will create incentives to avoid the demand charge. Although battery storage to reduce kW usage is not currently economical, once it is economical, customers will adopt it. At some point in the future, a residential net metering customers will have little use for utility services and may drop off the system all together, thus losing all revenue derived from the breakaway customers. This loss of revenue will require the utility to raise rates on remaining residential customers leading to a revenue and grid stability death spiral. Cutting the cord to the utility's service will lead to both a loss of reliability for both the residential net metering customer and RMP itself as it loses a diverse source of near sight generation for its other customers. The Commission should not encourage or support a rate design that will motivate ratepayers to disconnect from RMP's grid system.

The proposed NEM tariff which separates out residential net metering customers from other residential ratepayers will not promote rate stability. With such a small population of residential net metering customers, slight changes in costs will have a large impact on these ratepayers. A separate rate class must have sufficient numbers and enough diversity to avoid large changes in rates. This is one important reason for the Commission to keep the residential net metering customers in the same rate class and rate structure as all residential customers. Diversity within a rate class helps stabilize rates for all residential rate payers. The proposed three-part tariff for Net metering customers will lead to volatility in their monthly utility bills as it is much more difficult to control kW use than kWh use.

Q: What about undue discrimination within the residential class under the current tariffs?

A: This is one of the prime arguments utility companies use against residential net metering programs, that residential net metering customers are not paying their fair share of costs and that non-net metering customers will pay more than their fair share. To put this allegation into perspective we must first recognize that the residential class currently has some customers paying more than their fair share of costs to begin with. As I testified to earlier, given that RMP's revenue is collected via a customer charge, minimum bill, and a variable volumetric energy charge, high energy users (those who pay more than $999 per year) pay more than their fair share of the fixed costs and low energy users are being subsidized. Costs associated with residential service include fixed costs of generation and transmission and distribution along with the variable costs of fuel. The volumetric rate is intended to collect both a portion of the fixed costs and all of variable costs, so the average user will pay their fair share of both fixed and variable costs. A smaller than average user will pay less than their fair share of the fixed costs and a large than average user will pay more than their fair share of fixed costs. This inequity and subsidy is exacerbated by the fact that the residential rate schedule has a tiered structure so larger use customers pay an even higher average price than lower use customers. Thus, the residential rate structure starts out with some known and recognized subsidization and Commission approved subsidies. Residential net metering customers generally are larger users of electricity, before they install a residential solar system, compared to non-net metering customers, as shown in Joelle Steward's Table 4 "Differences in Customer Characteristics". To the extent that this remains true in the future, which appears to hold true, the subsidy claimed by RMP of non-net metering customer to net metering customer will just mitigate the subsidy that is already embedded in the current residential rate structure. Contrary to RMP's argument, the residential net metering program will help mitigate discrimination in the long and short-term, not make it worse.

Q: Could separating the residential net metering customers into their own class lead to discrimination within that class?

A: RMP's three-part rate design for its proposed Schedule 5 could create undue discrimination within the residential net metering class because most of the revenue will be collected through the demand charge with little transparency to the residential net metering customer. Some commercial and industrial net metering customers may be able to avoid the demand charge with some capacity management tools while other less sophisticated customers, such as residential, will not. The fall in revenue from the former customers will require higher revenues from the other residential net metering customers leading to some discrimination.

CRITIQUE OF RMP'S COMPLIANCE FILING

Q: Could you provide a critique of RMP's Compliance Filing?

A: There are a number of issues that pertain to RMP's Filing which call into question the reliability of its results. Some issues are quantifiable in dollar terms while other issues create doubt about whether the Commission can draw conclusions from such an analysis.

Q: Can you provide a brief synopsis of RMP's filing?

A: RMP provided two separate analyses as directed by the Commission. The first compares two cost of service studies over the 2015 test period. The first study measures the Actual Cost of Service (ACOS) which includes the net metering customers' participation. This is compared to a Counterfactual Cost of Service study (CFCOS) where RMP estimated what the cost of service would be without the electricity produced by the net metering customers. The Commission ordered that the analysis reflect the costs and benefits at the system, state and customer class levels. The second analysis, known as the NEM Breakout COS study, segregates the net metering (NEM) customers in the ACOS study into a separate class and assigns costs to that class of customers. The purpose of this analysis is to see whether the current tariff for this class collects the costs assigned to it and how it might impact the non-NEM customer class.

Q: What were the results of RMP's studies?

A: RMP concluded that the CFCOS has $3,722,000 higher net cost than the ACOS on a system level and a $1,659,000 increase in net cost on the residential class level. Thus, RMP concludes that the net metering program as currently constructed places a cost burden on other non-Net metering customers. RMP's NEM Breakout analysis shows mixed results depending on the rate schedule, but for the residential class the study shows that the NEM class is only recovering 60.6% of its costs, when including bill credits (which is just reduced consumption for behind the meter usage, and credits for exported energy), compared to the 96.1% of cost recovery for the non-NEM residential class. If bill credits are removed from "costs" to service a residential NEM customer the result is that a residential NEM customer covers approximately 92% of its cost of service which is only 4.1% below a residential non-net metering customer. Based on these analyses, RMP prematurely and incorrectly concludes that the rate schedule for the Net metered customers must be altered and a separate residential class for net metering customers should be adopted.

Q: Do you agree with RMP's conclusion that the net metering program produces a large net cost to the system, state and customer classes?

A: No, RMP has made several conceptual errors in their analyses and they have either not included certain benefits or have overstated costs. In addition, there are several methodological errors which call into question the validity of key parts of the study. As such, we recommend that the Commission make no or only incremental changes to the current residential net metering tariff.

Q: Could you provide some arguments to support your contention that RMP's ACOS vs. CFCOS overestimates costs or underestimates benefits.

A: Yes, but I will limit my analysis to the residential class as it is the class that RMP claims produces the largest net costs to the system. The residential class also makes up the bulk of Vivint Solar's customer base. RMP claims that the net cost of the residential net metering program at the class cost of service level is $1,659,000. This includes increased metering costs, increased engineering and administration costs, increased customer service/billing costs, net metering bill credits, partially offset by certain benefits, including lower net power costs. We have problems with the calculation of each component of the costs listed by RMP. However, the largest problem is with the net metering bill credits, due to RMP's attempt to reach behind the meter and into the ratepayer's home.

Q: What is the issue regarding the calculation of the net metering bill credits?

A: RMP estimates the costs of bill credits as the difference between the actual revenues collected in the ACOS and the revenues that would have been collected in the CFCOS. The problem is that RMP includes in this difference in revenues the amount of energy and its attendant revenues that were consumed by the net metering customers' onsite behind the meter. RMP is trying to collect for lost revenues that they incurred due to the customer reducing its demand for electricity through its own generation. RMP assumed in its filing that 44% of all energy produced from the residential solar system was consumed onsite behind the meter, never exported to the utility grid. Meaning 44% of RMP's "costs" attributed to bill credits should be considered lost revenue and a direct result of the ratepayer using less energy.

Q: Why is counting a net metered customer's usage of his own production not appropriate to consider a cost to RMP?

A: RMP's proposed treatment of the usage behind the meter as a bill credit cost is like trying to collect revenues from a customer because she reduces her demand for electricity by installing an energy efficiency measure such as a more efficient air conditioner or more efficient refrigerator or energy efficient lightbulbs. By the same measure, RMP cannot collect for lost revenues when a family member moves out or there is a change in lifestyle which reduces energy use for the household.

Q: What is the impact on net costs if RMP was not allowed to collect on lost revenues from usage behind the meter?

A: Eliminating these phantom costs from the calculation of bill credits would reduce the costs by approximately 44% or from $2,987,000 to $1,314,280.

Q: What about the other costs that are attributed to the net metering program such as the additional metering costs?

A: RMP has estimated that the additional costs associated with the meters for Net metering customers is $162 per meter. This meter will measure the flow of energy bi-directionally, so it will measure the energy coming into the home and the excess energy flowing from the home into the grid. A uni-directional residential meter costs approximately $107[4]. The issue is that RMP just calculates the costs of the new meters and does not acknowledge or quantify the offsetting benefits of redeployment of the uni-directional meter to other customers in the RMP service territory or its salvage value if it cannot be redeployed. With meter redeployment, the metering costs associated with the Net metering customers should be the additional costs of the meter, not its full costs. This will lead to a cost savings of $25,152 under the following assumptions:

- Redeployed meters:
  - 60% of meters are redeployed
  - 50% remaining useful live
  - Implies a 30% (60% x 50%) reduction in net capital cost
- Scrapped:
  - 40% of meters are scrapped
  - Scrap value of 10%
  - Implies a 4% reduction in net capital cost

4 See Table 4, page 20 of Joelle Steward's Direct testimony

- Capital cost of scrapped/redeployed meters versus bi-directional meters is 66%
- Total assumed savings of 22% ((30% + 4%) x 66%) or $25,152 of total residential metering cost of $112,000)

Q: What about the engineering/administrative costs assigned to the net metering program.

A: These costs are estimated to be $369,000 per year for the test year and it is based on the fully loaded hourly cost of a field engineer multiplied by the number of hours per application. The problem with this method is there are some fixed costs associated with the engineer and administrative functions and these costs should not be included in the analysis because they do not vary with the number of applications and connections. Average fixed costs will decline as more applications are processed and thus average total costs will also decline. The use of a fixed cost per hour for an engineer will overstate the incremental costs of serving an application and installation of a NEM customer. Another weakness of the method is that it does not recognize that there will be efficiency gains through learning by doing. As more applications and connection studies are done, workers will become more efficient at processing them and thus average costs will decline.

Q: What about the $72,000 in additional billing costs associated with the net metering program?

A: The main issue with this estimation of costs is that RMP expects to automate its net metering billing system in the future and when they do, the costs associated with billing NEM customer will be a fixed cost that will not change with additional residential Net metering customers. Thus, the estimate for the average costs associated with the billing of net metered customers will decline in the future and the current estimate will overestimate future billing costs.

Q: What are the benefits identified by RMP of the net metering program?

A: The benefits associated with the net metering program include lower net power costs, lower line losses, and lower inter-jurisdictional cost allocation. RMP did not try to quantify other measureable benefits, such as lower risk associated with meeting stricter environmental regulations and avoidance of fuel prices volatility. To be clear, RMP has recognized the following as benefits (i) avoided plant O&M costs, (ii) avoided transmission and distribution costs, (iii) avoided capacity investment, and (iv) increased grid resiliency; however, RMP did not take them into account in its analysis.

Q: How did RMP calculate the value of net power costs that are avoided by the net metering program?

A: RMP used its Grid Model to estimate the value of the energy that was provided by the residential Net metering customers. But first it had to estimate the amount of power that was generated by the customer owned solar panels. Once the distributed generation from solar panels was estimated, the Grid Model was run assuming the power generated by the residential NEM customer would have to be produced or purchased by RMP. RMP then compared the net power costs of this counterfactual world with a base case Grid model that was submitted on April 30, 2015 for it Schedule 37 (QF) filing. The difference between these two Grid runs produces the net power costs savings as a result of the net metering program.

Q: How did RMP estimate the amount of power generated from the Net metering customers.

A: RMP estimated the NEM power by installing special meters that measured the output from the solar panels. There were 36 customers, i.e., observations for this portion of the study. The data derived from the production profile studies form the basis for residential NEM customer production data that is replaced in the CFCOS study. This production data is one of the primary inputs into the Net Power Cost analysis which derives the value (benefit) of NEM customer solar generation.

Q: Were there any problems or issues associated with this generation study?

A: Yes, there were a number of problems or inconsistencies with the generation study that would call into question the validity of the results. They include a ridiculous and faulty sampling and RMP's decision not to weather normalizes the results is equally faulty. Failure to normalize for weather when the year had abnormal weather conditions and a different system peak can lead to inaccurate forecast of NEM generation. It would be better if RMP had at least two or three years of data on solar production and a broader scope and larger sample size.

Q: Can you elaborate on the sampling issue?

A: Yes. The 62 sample was originally selected so it was representative of the variety of different usage levels or strata in the general population of Net metering customers as a whole. This was the original sample of the load study. However, the sample was reduced to 52 to eliminate wind generated Net metering customers and it is unknown whether the 52 sample is representative or not in terms of the strata. Second, the sample that was used to establish the generation and production profile of solar net metered customers was only 36 observations. The sample for the actual production measurements was taken from different counties and then the sample production profile observations were weighted by the number of Net metering customers in each county. However, in some cases there was only one metered customer in the county, from a statistical perspective one observation might be an outlier and not representative of the population in that particular county. This issue is exacerbated by the weighting process. This could lead to an inaccurate estimate of the power production profile. Further, if stratification of usage was employed correctly, the sample would have to have usage strata for each county; the sample clearly does not do that.

Q: What about lack of weather normalization of the load study?

A: In its response to Vivint Solar's Data Request 2.12 (b), RMP stated that "normalization was not necessary because actual 2015 data was used which was a representation of actual weather results." However, we note actual weather in 2015 differed from "normal" weather based on a number of measurable factors:

One: Heating degree days for Salt Lake City in 2015 were 20% below norm[5];

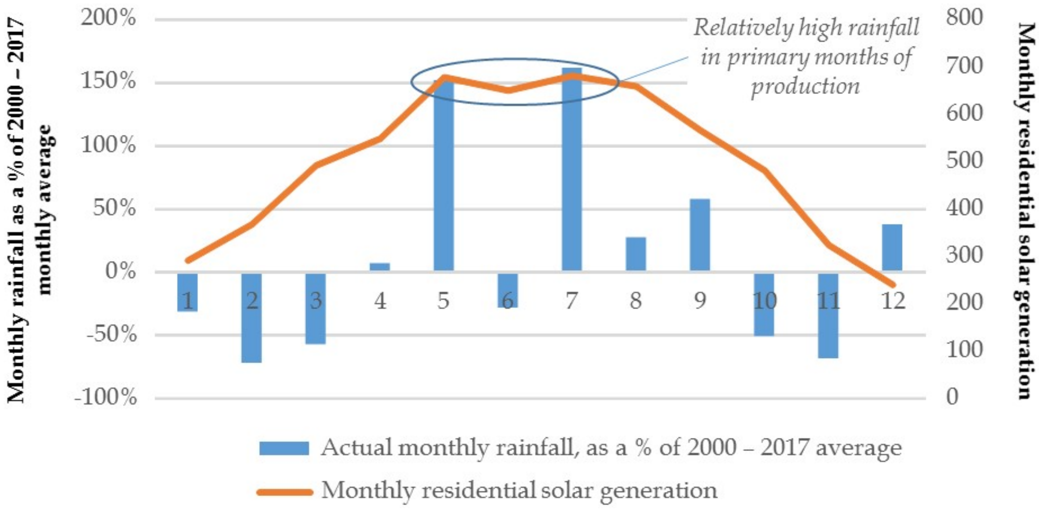
Two: Cooling degree days for Salt Lake City in 2015 were 36% above norm; and

Three: Rainfall (as well as cloud cover) was significantly above the recent monthly means in several months, including some months that are the most productive from a solar generation perspective, according to NREL. In the testimony of Robert M. Meredith (exhibit RMP_ (RMM-3), page 2), it was noted that "the residential distributed generation production curve during the months of May and December is lower than PVWatts® curve." A possible explanation provided was cloud cover on an hourly basis. The five-year averages for May and December were 55% and 60%, respectively, whereas actuals during the study for May and December were 67% and 66%, respectively. An

5 Source: National Oceanic and Atmospheric Administration ("NOAA")

analysis of monthly rainfall (as a proxy for cloud cover) also demonstrates variances in weather from recent historical “norms”. The figure below shows monthly rainfall in 2015 as a percentage of monthly averages for January 2000 through April 2017[6]. These percentages were compared against the monthly expected generation from residential rooftop solar according to NREL PVWatts® for Salt Lake City[7]. This figure demonstrates some significant variances from historical averages—both positive and negative—including in May, as noted above.

Figure 1: Monthly 2015 Rainfall as a % of 2000 – 2017 Monthly Actuals vs. Expected Residential Rooftop PV Generation per NREL



Based on the foregoing, we contend that actual 2015 weather differed from what would be a “normal” weather year, particularly in months of relatively high solar production, and, as such, should not be used as the basis for rate policy or rate setting.

Q: You have identified problems with the generation and load studies that provide

6 Source: National Centers for Environmental Information (Climate at a Glance for Salt Lake City)
7 Based on standard NREL residential solar configuration (TMY2 data, system size of 4 kW, fixed array, array tilt of 20 degrees, array azimuth of 180 degrees).

critical inputs to the GRID model, are there any other issues with the GRID's Net Power Cost calculations?

A: Yes, there are three issues. First, RMP did not include all of the costs associated with the additional generation required to replace the residential NEM generated power that was included in the CFCOS. Second, the Commission did not include a capacity value that the net metering program provided to the system. Third, RMP includes an integration adjustment that is not appropriate.

Q: Please explain how RMP estimates the power costs that were included in the CFCOS and identify what costs were excluded.

A: In order to determine Net Power Costs, one of the quantified benefits of rooftop solar, RMP used its Generation and Regulation Initiative Decision Tools ("GRID") production cost model to calculate the cost of generation and/or net market purchases that would be necessary to replace the estimated generation from rooftop solar systems owned by residential NET METERING customers. According to RMP, the assumed variable costs of production in the GRID model are based solely on: (1) delivered fuel costs and (2) unit heat rate. The model did not assume other variable production costs that would normally be included in unit dispatch costs including, but not limited to, variable O&M costs, consumables (i.e., water, etc.), ash disposal, etc. According to the Energy Information Administration, the assumed non-fuel variable costs of production for coal-fired generation and gas-fired combined cycle units are $4.74/MWh[8] and $3.42/MWh[9], respectively. The dollar impact of this exclusion for residential customers is estimated to

8 Source: EIA Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants, April 2013. Amounts expressed in 2012$ escalated at 2.0% inflation.
9 Source: EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016

be $45,000.

Q: The Net Power Cost analysis estimated the energy value of generation from net metering customers in the CFCOS. Is there capacity value from net metering generating systems that should also be included?

A: Yes. Throughout its Compliance filing, RMP repeatedly states that since "the peak energy output of these solar systems occurs in the middle of the day prior to the timing of both the system and class level peaks…the peak demand is either unchanged or reduced very modestly" (Direct testimony of Joelle Steward, lines 346 – 350). As such, RMP provides little to no value to the capacity of the solar resource, However, the generating capacity of rooftop solar does have value as a capacity resource and we have estimated the market value of that capacity in 2015. According to the 2015 IRP, PacifiCorp was projected to sell 942 MW of capacity in 2015[10]. Further, according to a PacifiCorp and CAISO study entitled "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration" dated October 2015 (PacifiCorp/CAISO Technical Study), at the time of the study, PacifiCorp had 982 MW of transfer capability into CAISO. This capability represented the amount of transfer rights then held by PacifiCorp. The capacity of the rooftop solar system (i.e. the reduction of peak load) frees up capacity that PacifiCorp could otherwise monetize through capacity sales. The existence of incremental available transfer rights into California suggests the ability to monetize this excess capacity. The value of this capacity in 2015 was estimated as follows:

[10] 2015 Integrated Resource Plan, Volume 1, Table 8.8, page 197 (combined capacity sales for PacifiCorp East and PacifiCorp West)

Table 1: Value of Net Metering Capacity in CFCOS

Description	Value	Source
Average number of residential customers (2015)	4,390	RMP_(RMM-5)
Average residential system size	5.5 kW	RMP Compliance Filing
Total average capacity (2015)	24.15 MW	
Capacity value (%)	53%	2017 IRP (average for fixed tilt in UT)[11]
Eligible capacity (MW)	12.80 MW	
Capacity pricing ($/kW-yr)	$34.80	Value of California RA Capacity for 2012-2016 per the CPUC as reported in the PacifiCorp/CAISO Technical Study (page 12)
Value of net metering capacity ($000)	$445	

As calculated above, the value of the capacity associated with residential net metering customers in 2015 was estimated to be approximately $445K annually.

Q: What is your concern about the integration costs that are included in RMP's analysis?

A: RMP decreased the value of residential solar generated power because it stated that this solar power needs to be integrated into the system, thus lowering the value of the residential solar generated energy by $2.83 per MWh, this estimate of integration costs did not come from an actual study rather it was the Commission accepting a proposal from the Division. In Utah PSC Docket 12-035-100, Order on Phase II Issues issued August 16, 2013; the Commission decided that "Given the absence of a solar integration study, we accept the Division's proposal to respectively apply 65 percent and 50 percent of the wind integration cost in PacifiCorp's 2012 WIS to Fixed Solar and Tracking Solar

11 Capacity value for solar PV per RMP 2017 IRP documents. Refer to Public Input Meeting 4, September 22-23, 2016, page 54. Refer to additional discussion related to the NEM Breakout Study.

resources. We therefore direct PacifiCorp to apply a solar integration charge of $2.83 per megawatt hour for Fixed Solar resources…". Thus, the calculation of Net Power Costs includes the cost to integrate solar resources due to the variability in solar generation from cloud cover and the need to ramp resources up and down in response. The $2.83 per megawatt hour was used in the calculation of Net Power Costs in the CFCOS. However, other filings by RMP suggest that the costs of solar integration are likely significantly lower.

In its FERC Form 714 filing for 2015 (Part II, Schedule 6), PacifiCorp states that:

"PacifiCorp does not calculate a system lambda. The PacifiCorp West balancing authority area carries a significant amount of its regulating margin on hydro resource, which do not have a fuel pricing component to contribute to a meaningful system lambda. The PacifiCorp East balancing authority area utilizes the same hydro resources as incremental regulating margin through dynamic transfers, also precluding a meaningful system lambda calculation."

Given the presence of significant hydro resources on the margin and their availability for regulation that lack a fuel pricing component to the point that precludes a "meaningful system lambda, the actual cost to integrate solar resources is nominal. The benefit of excluding this integration cost is up to $45,000 for residential customers (excluding the 43.6% of generation that is behind the meter).

Q: Were class allocations adjusted to account for changes otherwise made to the cost / benefit analysis?

A: Yes. As previously noted, it was recommended to reduce the total amount of residential bill credits by the amount of the credits attributable to behind-the-meter generation and consumption, which was estimated to be 43.6% of self-generation. In order to adjust for energy-related expense allocations (and not double-count the benefit of behind-the-meter generation in the allocation of energy-related expenses), the monthly amount of net energy for residential (Sch 001) customers in the CFCOS study was reduced by the estimated behind-the-meter generation. The adjustment in kWh terms was calculated as the difference in monthly net energy between the ACOS and CFCOS multiplied by 43.6%. After making the adjustment in energy usage and running it through the CFCOS model, the result was a reduction in the cost of service for the CFCOS study (as adjusted). This also reduced the difference in expense allocations between the ACOS and CFCOS (as adjusted) by $288K. Thus, the benefit associated with lower class allocation cost was reduced by the $288K and double counting of the residential net metering customer's usage behind the meter was avoided.

Q: Your adjustment to the Bill credits required an adjustment for the interjurisdictional, state and class allocation factors, doesn't it require an adjustment to the estimate net power costs estimates?

A: Yes, it does. We used the same methodology for net power costs by adjusting the results of the GRID Model to adjust for the behind the meter usage of the net metered customers. We simply reduced the amount of the savings by the behind the meter percentage or 43.6%

Q: Have you been able to quantify the differences between RMP's estimate of the net cost of the residential net metering program and the estimate of costs of the program that include your corrections?

A: Yes. Once we incorporate the corrections to RMP's estimates, the net cost to the residential class resulting from the net metering program is $416,366 or $14.71 per MWh and $94.84 per customer per year. These estimated costs shifts are substantially lower than RMP's estimate and given the benefits of the program that were not included in the analysis, there is no justification for changing the net metering tariff or the program.

Q: Are there other issues with the ACOS and CFCOS analysis?

A: Yes, there might be. As described below in our discussion of the NEM Breakout analysis, RMP appears to underestimate the peak shaving abilities of roof-top solar. Although we have not been able to quantify the impact of this in the ACOS and CFCOS, if indeed they used a 7% peak reduction rather than a 47% peak reduction in their cost of service studies it would over allocate generation and transmission costs at the jurisdictional, state and class level. Given our estimation of the impact in the NEM Breakout study, this could have a major effect on the net cost calculation.

NEM Breakout Analysis

Q: Can you describe how RMP performed the second analysis where they broke out a separate rate class for residential Net metering customers?

A: The Commission ordered RMP to perform a second analysis "to segregating 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 other participate." 12 RMP started with the class ACOS study and separated classes for net metering customers. The characteristics of their cost of service were identified, removed from the overall class they were separated from and placed in their own NEM class. The characteristics include

12 November 2015 Order

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.

Q: Based on your review of the NEM Breakout Study did you find any issues with respect to the key assumptions and/or findings?

A: Yes. The primary issues surround the ability of rooftop solar to reduce peak demand. RMP claims throughout its Compliance Filing that rooftop solar generation has little to no impact on peak reduction.

"This solar generation often does not coincide with RMP's peak load, thus only minimally reducing that load. Company witness Mr. Marx testifies that a net metering customer's peak production occurs during the spring months while their peak load, and that of other customers occurs during the summer months."[13]

"In addition, because peak solar generation often does not coincide with the time of RMP's peak load, net metering customers' private generation systems have only a modest ability to reduce peak load."[14]

"The peak energy output of these solar systems occurs in the middle of the day prior to the timing of both the system and class level peaks. As a result of this output, the energy requirements for these customers are reduced, but the peak demand is either unchanged or reduced very modestly."[15]

"My testimony demonstrates that rooftop solar generation does not reduce the peak demand on the distribution system to a degree that could warrant a reduction in

13 RMP Compliance Filing, page 13 (Discussion, section B)
14 RMP Compliance Filing, page 9 of direct testimony of Gary W. Hoogeveen, lines 192 - 196
15 RMP Compliance Filing, page 19 of direct testimony of Joelle R. Steward, lines 346 - 350

infrastructure."[16]

However, these assertions are materially different from other estimates of the capacity value (or peaking shaving capability) of solar PV resources. For instance, in its "Solar Energy and Capacity Value" fact sheet (September 2013), NREL states that "in the western United States, the capacity value of PV plants can be in the range of 50% to 80% of their alternating current (AC) rating…". NREL also lists several specific studies which had capacity values ranging from 20% to 78.3%, with most in the range of 40 – 60%.

Utility District Studied (Authors)	Summary of Methodology	Reported Capacity value
Arizona Public Service (APS 2013)	Performance data from installed system in service territory, load profiles from 2003 to 2007; single-axis tracking; deployment projections for 2015; ELCC simulations for existing capacity and next 100 MW built	45.9%–48.4%
Nevada Energy (Lu et al. 2012)	Nevada Energy southern system generation fleet in the 2007 study year; ELCC calculation using LOLE of 1 day in 10 years	57.4%
Nevada Power (Perez et al. 2008a)	Satellite-derived resource data to simulate output; simulated 2% PV deployment; 30° SW-facing fixed systems; ELCC calculation	71%
New York ISO (Perez et al. 2009b)	South-facing fixed slope; ELCC calculation for simulated 2% PV grid penetration using 2007 generation and load data	44.3–78.3%
Portland General Electric (Perez et al. 2008a)	Satellite-derived resource data to simulate output; simulated 1% PV deployment; 30° SW-facing fixed systems; ELCC calculation	31%
Public Service Colorado (Xcel 2013)	2009-2010 historic load and solar generation; single-axis tracking; ELCC calculation using LOLE of 1 day in 10 years	41%–47%
TriState (TriState 2010)	LOLP method, with expected capacity availability during peak load hour; unclear assumptions for generation and load data	20%–57%

Q: Are there other filings by RMP which suggest a different conclusion to the capacity value and peak-shaving ability of solar PV?

A: Yes. According to PacifiCorp's 2017 Integrated Resource Plan filings[17], the capacity

16 RMP Compliance Filing, page 2 of direct testimony of Douglas Marx, lines 27 - 29
17 Public Input Meeting 4, September 22-23, 2016, page 54

contribution results for solar are assumed to be 51.0% in Milton, UT and 53.0% for average fixed tilt solar in Utah. That is, there is an estimated 47.0% reduction (1 – 53.0%) in peak load for each unit of fixed tilt solar added in Utah on average. This suggests that the capacity contribution for solar based on the IRP analysis is significantly higher than RMP's testimony in the Compliance Filing would suggest.

Q: Why is the amount of assumed peak shaving or capacity value of solar PV important?

A: The NEM Breakout Study was intended to take RMP's actual 2015 cost of service and allocate them to various customer classes, with separate class breakouts for Net metering customers, including residential. According to RMP, most of the costs to serve residential customers are fixed, not variable, in nature. Based on Company estimates, approximately 63% of all residential cost of service was deemed to be demand-related"[18]. Demand-related charges in the NEM Breakout Study are allocated based on system coincident peak and state distribution coincident peak. According to RMP, "most of RMP's costs are allocated in class cost of service studies based on demand-based measurements because the system is designed to serve load at different peaks."[19] As such, accurately estimating the reduction of peak load driven by solar PV is very important to cost allocation.

Q: What is the estimated impact on the NEM Breakout Study of using a reduction of peak load consistent with RMP's prior IRP filings with the Commission?

A: To estimate the impact of additional demand reduction on the NEM Breakout Study, we reduced the assumed system coincident peak and the distribution coincident peak in the

18 RMP Compliance Filing, page 20 of the direct testimony of Joelle R. Steward, table 5.
19 RMP Compliance Filing, page 20 of direct testimony of Joelle R. Steward

"ACOS UT Dec 2015 NEM Breakout" model by the estimated incremental reduction suggested by RMP's IRP filing. The actual amount of peak demand reduction for system coincident peak and distribution coincident peak was not expressly disclosed in the RMP Compliance Filing but, based on other testimony cited above; this reduction was deemed "modest". We do note that the "Distribution Rooftop Solar Study", a study conducted by RMP in 2014 on a single circuit, noted that the reduction in circuit peak demand was approximately 7%. As such, we used this as a proxy for the modeled reduction in both system coincident and distribution coincident peak demand. The revised peak reduction was based on the peak reduction implied by RMP's IRP filing for average Utah fixed tilt solar of 47.0%. The adjustment to monthly system peaks in the NEM Breakout Study model for 'Sch 001 NEM' residential customers ('Demand' worksheet, line 155 for system coincident peaks) was X *(1.07) * (1 - .47).[20] This was intended to gross up peak load by the assumed reduction modeled and then reduce that amount by the reduction implied from RMP's IRP filings. We also adjusted the peak load for 'Sch 001' residential (non-Net metering customers) so that the sum of the 'Sch 001 NEM' and 'Sch 001' peaks were consistent with the respective monthly peaks for residential customers in the 2015 ACOS model.

The filed NEM Breakout Study suggested a subsidy of NEM residential customers by non-NEM residential customers of approximately $1.1 million[21]. Modeling a reduction in system coincident peak consistent using the IRP peak reduction of 47% results in lowering the calculated subsidy by $408K to $687K.

Q: Did you note any potential issues with the load study that may have contributed to

20 From ACOS UT 2015 NEM Breakout Model
21 RMP Compliance Filing, page 26 of the direct testimony of Robert M. Meredith and Exhibit RMP_(RMM-13).

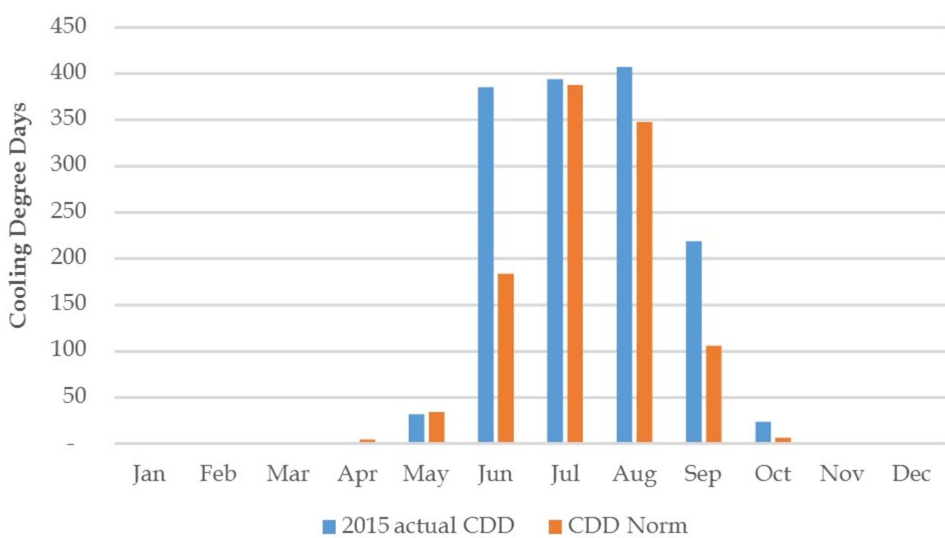
the discrepancy in peak demand reduction under the load study relative to RMP's IRP-related filings?

A: Yes. Potential issues identified include the following:

- The 2015 load study does not appear to have been weather normalized.
- The number of samples within individual strata may be lower than targeted sample size, thereby potentially skewing results.
- For some counties there appears to be just one observation.

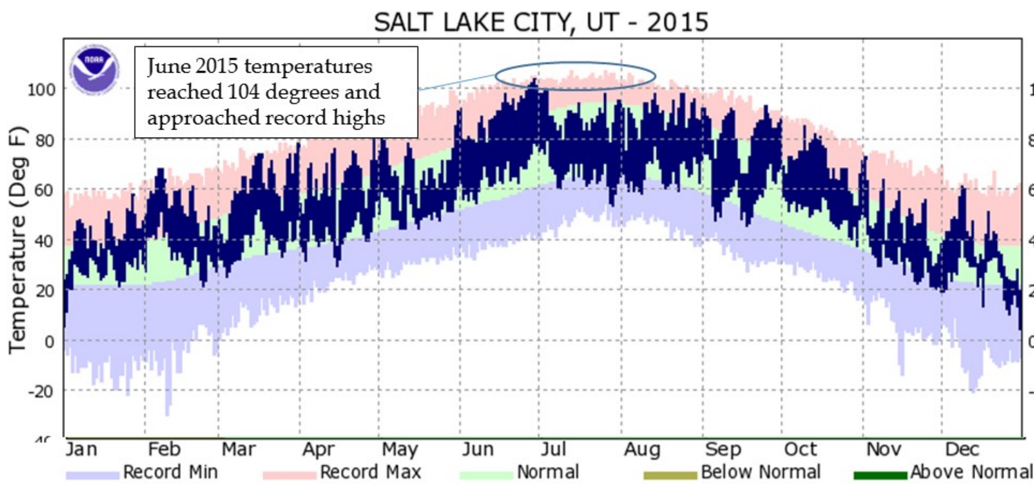
Q: Could you discuss why the issue of weather normalization is a problem?

A: The NEM load does not appear to have been normalized. According to RMP testimony, the peak month (in the load study) was June 2015[22], however, the peak load is normally July[23]. As noted below, the summer months in 2015 were warmer than usual, particularly, June which had more than twice the number of cooling degree days as normal.



22 RMP Compliance Filing, page 11 of the direct testimony of Robert M. Meredith testimony, line 223.
23 RMP Compliance Filing, page 4 of the direct testimony of Douglas L. Marx, line 70.

In fact, late June 2015 temperatures reached temperatures of 104 degrees, approaching record highs and far exceeded normal highs for June and July.



Q: Given these issues with the NEM Breakout Study, what is your recommendation for the Commission?

A: Given the multiple uncertainties surrounding this study, we recommend that the Commission disregard the study's conclusion and order RMP to redo the analysis after correcting for the errors. The Commission should not use the conclusions RMP draws from this study to make findings in this case. The load study should cover multiple years.

Q: What is your opinion on RMP's proposed tariff, Schedule 5 for residential customers?

A: The proposed schedule 5 with its three-part tariff will have a chilling effect on the solar industry in Utah. It will kill the residential solar industry and deny Utah ratepayers the opportunity to economically install solar energy system. The tariff is composed of three parts: the customer charge of $15 per month and a demand charge of $9.02 on-peak and an energy charge of $.03814 for all kWh. The most onerous part of the tariff is the demand charge as it creates a disincentive to invest in roof top solar. The demand charge, as testified to earlier, is difficult for residential consumer to interpret and understand. Therefore it will be difficult to implement. RMP argues that the tariff more closely aligns with cost causation and therefore is necessary, but this is true for non-NEM residential customers also. Given residential consumers' uncertainty surrounding the nature of demand charges and how distributive generation could avoid them, the likely outcome will be for residential consumers to forego self-generation. The relatively low and flat energy rate creates a disincentive to save on energy. The past dozen or so IRPs have shown that demand-side efficiency is one of the most cost effective resources available to the system.

Q: What are your concerns about the $15 per month customer charge?

A: The $15 customer charge was derived by including the $8 charge based on traditional costs of the customer services, meters and line services plus the cost of transformers. This was RMP's justification for the higher charge and it adds an additional $7.00 to the customer charge for Net metering customers.

Q: Why are transformers included in the calculation of the NEM residential customer charge, while transformers are not included for non-Net metering customers?

A: Witness Marx argues that Net metering customers use the electrical grid differently than non-Net metering customers and put a greater cost burden on the grid system because not only do they receive power from the grid but also export power to the grid. Citing the inverse relationship between ambient temperatures and PV output, Marx argues that net zero Net metering customers could export more power to the grid compared to its peak load demand. Thus, he argues in May the maximum exported power could be as much as

50% more than the maximum imported power in July. However, this argument is a red herring and only applies in limited cases. First, Marx assumes that the NEM customer sizes his solar system for zero consumption of energy; next he assumes that all customers on the transformer are also zero net energy Net metering customers. If one or two customers on the transformer are a non-NEM customer or less than full zero net energy customer then the exported power from the NEM customer will simply negate the inflow of power to the non-Net metering customers. Marx's argument appears to be an unlikely scenario given the current penetration levels of solar panels on the system and the fact that only 13% of all net metered customers are zero net energy. Based on two modeling studies in the Northeast #16 circuit and the Bingham #11 circuit, he concludes that solar panels will only offset 7% of peak demand on a given circuit. This may be true for the present equipment on the circuit, but it may delay the need for future upgrades to the circuits.

Q: Witness Steward was asked about the potential impacts of the costs shift to other residential customers if net metering is not addressed, do you care to comment.

A: Yes, she states that according to RMP's analysis, for 2015 the net cost to other residential customers is $1.8 million and it is estimated to be $6.5 in 2017 and will increase to $78 million per year in when the program meets the 20% cap. She also states that the cumulative cost shift will be approximately $667 million over a 20 year period. However, as our analysis indicates, RMP's analysis overestimates the costs and underestimates the benefits of the net metering program. In regards to her statement that the cumulative costs are $667 million, we assume these total cumulative costs do not take into account the time value of money. But more importantly, if we are going to look at the 20 year horizon, then we should look at the net benefits of the net metering program over that same period which the 2015 IRP indicates are $706 Million dollars in present value revenue requirement which does take into account the time value of money.

Q: Can you discuss the general framework for analysis that the Commission required of RMP when calculating the benefit and costs of the net metering program?

A: Yes, the Commission took an incorrect view and misinterpreted the Legislature’s intent. By restricting the analysis to a cost of service study that takes the revenue requirement as a given and then assigns costs to the various classes based on the cost causation principle, the Commission has mistakenly left out important costs and benefits of the net metering program by requiring the analysis to take place solely within twelve month cost of service allocation study.

Q: What logic did the Commission use to restrict the analysis to a one year period used in a cost of service allocation study?

A: I believe that the Commission made a fundamental error in its logic. The Commission confused cost of service regulation with a cost of service allocation study. On page 15 of their July 1, 2014 order in this docket, they state:

> “In sum, we interpret Subsection One in a manner consistent with its plain language and the Commission’s traditional role as utility regulator. As a matter of law, we conclude Subsection One requires the Commission to consider costs and benefits that accrue to the utility or its non-net metering customers in their capacity as ratepayers of the utility. It necessarily follows that any cost or benefit to be included in the Subsection One analysis must be a cost or benefit that has

some impact on the utility's cost of service."24

The traditional method of utility regulation is to set rates base on the utility's cost of service which includes a fair rate of return on investment. Cost of service regulation consists of three separate parts: the determination of revenue requirement, the cost of service allocation study and rate design. The Commission is well aware of the process to determine all three stages so I will not go into in detail here. However, what the Commission has done by adopting a cost of service allocation study methodology to evaluate the cost and benefits of a net metering program is to leave out of the analysis what is arguably the most important stage, the determination of revenue requirement.

Q: Why is it important to distinguish between cost of service regulation and cost of service allocation study?

A: Like I alluded to above, using a cost of service allocation study which allocates costs amongst the different classes based on the costs each class places on the system fails to evaluate what costs or benefits that the net metering program contributes to the overall revenue requirement. RMP's 2015 IRP explicitly finds that a scenario that assumes a higher penetration of net meter customers has a lower present value revenue requirement than the base case. Surely, the legislature did not intend for the Commission to ignore such future benefits or costs.

Q: But those benefits occur in the future not today, so they are irrelevant to today's ratepayer.

A: Today's ratepayer will be tomorrow's ratepayer unless they move out of RMP's jurisdiction or die. To ignore an action today that will provide future benefits because it does not benefit us immediately is short sighted and will lead to a diminished future. It's like a young worker telling his investment advisor that he won't save for his retirement because he will not see any benefits in the next (test) year.

Q: How will the Commission be able to set rates for net metering customers if it does not use a

24 Italics not in the original order.

test year?

A: The Commission should first determine the costs and benefits of the net metering program by looking at the impact the program will have on ratepayers and RMP. If the long term benefits of the program outweigh the long run costs, the Commission should take no action. But if the long-term costs are greater than the long-term benefits than the Commission should take action and use test year data to set rates that will equate costs and benefits.

Q: Are any there any other long-term benefits of net metered generation that can be quantified?

A: Yes, we have identified two possible long term benefits; the first is Renewable Energy Credits (RECs) RMP will not have to purchase and second is the avoidance of any future carbon reduction expense, i.e., a carbon tax.

Q: Please explain how NEM generation will avoid the purchase of RECs and if possible quantify this benefit.

A: Yes, although the "green" attributes of the NEM generation do not accrue to RMP (absent a negotiated agreement per Commission direction), the generation that is produced and consumed, on site will be a cost-savings to RMP in future years when the Utah RPS goal becomes effective. With the enactment of "The Energy Resource and Carbon Emission Reduction Initiative" (SB202) in March of 2008, the state of Utah adopted an RPS goal of 20% of adjusted retail sales from renewable resources (as defined) by 2025. According to Exhibit RMP_ (RMM-4), 12,341 MWhs are generated and consumed onsite by NEM residential customers. If this generation was not produced and consumed, RMP would be required to procure 2469 (20% of the total) RECs annually. Based on RMP's 2015 IRP, the economic break-even price for unbundled RECs in Oregon, according to RMP's System Optimizer, was $18/MWh. Using this value as a proxy for unbundled RECs in Utah yields an annual benefit of $44k/year.

Q: What about if there is a carbon reduction program?

A: Similarly, upon implementation of a carbon reduction program, the onsite generation from the net metering program yields significant benefits. Without this generation, RMP would have to either: (a) pay a carbon-tax on replacement thermal generation from Company resources or (b) pay higher prices for replacement power from the market (assuming thermal resources are on the margin), since the variable carbon costs would be included in unit dispatch costs. We calculated the economic benefit of this generation using the following assumptions:

- Carbon emissions rates:
  - Coal: 215 lbs/mmbtu (per EIA)
  - Gas: 117 lbs/mmbtu (per EIA)
- Heat rates (assumed)
  - Coal: 10,000 btu/kwh
  - Gas: 7,200 btu/kwh
- Carbon prices (per RMP 2015 IRP, Volume 1, page 146)
- Coal / gas mix: 81.7% / 18.3% (calculated from the relationship of coal-fired generation and gas-fired generation replacement power in the Net Power Cost Analysis)

Based on the foregoing, the average cost savings to RMP over the forecast period 2015 to 2034 is $391K.

Q: Could you summarize your testimony?

A: Yes, we have analyzed the Company’s Compliance Filing and have found that there are too many errors and faulty assumptions that were made which exaggerates the costs imposed on the Company and other customers by the net metering program. The Filing also underestimates the benefits. This is not to be unexpected as distributive generation such as net metering represents a competitive force utilities would rather not deal with and if possible put at a competitive disadvantage.

There are a number of flaws in the study; the load and generation studies have inadequate sampling and too few numbers of observations to render a reliable statistical inference. It should be noted that these questionable studies provide key inputs into both cost of service studies: the ACOS and CFCOS study and the NRM Breakout study. Without confidence in critical inputs to a study, one can have little confidence in the output of the results. They also counted in the bill credit cost, , the net metered customers use of their own generation which is inappropriate. They improperly assigned costs of transformers to NEM customers. They don't properly evaluate capacity value of net metering program and there are numerous other errors in the study that are described in my testimony. They have sponsored a tariff that will be hard for customers to understand and the tariff will destroy the solar industry in the state of Utah like it did in Nevada. The Company has asked for a change in a tariff that will bring in more revenue, but has done so outside a general rate case while RMP appears to be earning its authorized return. I strongly recommend that you keep the net metering program as is, order the Company to make corrections to it load and generation studies of net metered customers and continue the study for more years and finally revisit this issue only during a general rate case.

Q. Does this conclude your direct testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on June 8, 2017, I sent a true and correct copy of the pre-filed direct testimony of Richard Collins representing Vivint Solar, Inc. by email to the following:

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