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Memorandum

TO: Public Service Commission

FROM: Division of Public Utilities
Chris Parker, Director
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Artie Powell, Manager
Bob Davis, Utility Analyst
Charles Peterson, Utility Technical Consultant

DATE: February 6, 2015

SUBJECT: **14-035-114** In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program

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COMMENTS from DPU

Background

On August 29, 2014, the Public Service Commission of Utah ("Commission") issued its report and order in Docket No. 13-035-184 ("Order"), approving an uncontested settlement stipulation and declining to implement PacifiCorp's ("Company") proposed net metering facilities charge. Recognizing the importance of the issues raised by parties in the general rate case, the Commission established Docket 14-035-114 to examine the costs and benefits of PacifiCorp's residential net metering program.

On November 21, 2014, the Commission issued Notices of Comment Period and Scheduling Conference ("November Notice") in this docket. The November Notice provides

dates for comments and reply comments on February 6, 2015 and February 20, 2015, respectively, regarding issues related to the appropriate analysis for examining the costs and benefits of PacifiCorp's net metering program.

On November 5, 2014, a technical conference was held in which the Company presented its plan for performing a load research study focused on residential net metered customers, specifically on those residential customers with Photo Voltaic ("PV") panels.[1] This study will not be completed until approximately September of 2015. Accordingly, the Commission requested that the evaluation of the costs and benefits of PacifiCorp's net metering program be completed in steps.

The initial step is designed to establish the appropriate analytical framework for making the required determinations under Utah Code Ann. § 54-15-105.1. Such a framework will include the types of analyses that must be performed, the components of costs and benefits to be included in the analyses, and the sources and time period of data inputs.[2] The parties will have the opportunity to provide written comments as needed to narrow issues where disagreements on the appropriate framework arise.

For these comments, the Commission is seeking input on four items:

(1) Whether the traditional costs and benefits test equations (e.g. the utility cost test, the total resource cost test, the ratepayer impact measure test, and the participant test) and metrics (e.g. benefit to cost ratio) used to evaluate utility-sponsored demand side management ("DSM") programs can and should be applied to examining the costs and benefits of PacifiCorp's net metering program.[3]

(2) Comments on the applicability of some or all of these tests, or description of any other type of analysis, for examining the costs and benefits of PacifiCorp's net metering program.

(3) Interested parties will consider the consistency of any proposed analysis with the statutory definition of requirements of the net metering program.

[1] It is assumed that roof top solar comprises the majority of the residential net metering program in this docket.
[2] See http://www.nrel.gov/docs/fy14osti/62447.pdf. A copy is available by email from the DPU
[3] See Docket No. 09-035-27 and March 1995 "Demand Side Resource Cost Recovery Collaborative Report, pg. 14

(4) Request that the parties comment on whether the types of analyses to be used will vary depending on whether the analysis examines residential or non-residential net metered customers.

General Discussion

Some of the parties concluded in the 13-035-184 general rate case docket proceedings that residential roof top solar and non-residential roof top solar should be evaluated similarly to DSM. As such, the costs and benefits should be calculated in the same manner. The Division does not agree with this entirely. At a basic level, both DSM and roof top solar or other renewable resources in the form of Distributed Generation ("DG") reduce the utility's load. However, they do so in different ways at different times of the day and not necessarily in conjunction with the system peak hour.

DSM lowers the load through efficiency resulting in the utility seeing a loss in revenue and possibly lower system costs, which are recovered through the revenue requirement process. These reductions in load generally tend to be stable reductions, not ones confined to specific times. Thus, they reduce the utility's load in all hours. The utility does not have to be concerned about system reliability, higher infrastructure and other resource costs, balancing of the system and unintentional islanding, just to name a few potential issues, as a result of DSM. Net metering programs on the other hand, due to the intermittent nature of non-storage renewable resources, create the need for the utility to be observant of all these factors and others. As a result of the existing tariff structure and the administration of the net metering program, the Company may not be wholly compensated for these additional costs. Net metering customers are currently compensated for generation at the retail rate on a monthly basis.

Currently a significant portion of the fixed distribution costs are included in the volumetric electric rates. While DSM programs reduce the peak circuit load potentially reducing distribution costs, customers still pay for distribution costs on the remaining energy purchased. There is little evidence suggesting net metering customers offer the same cost avoidance. Over the course of a month, the net metering customer's generation is credited towards the customer's utility bill at the retail rate along with the booked excess generation. Thus, the Company does not

collect the revenue to cover its distribution costs that it normally would from a non-net metered customer with similar contribution to peak load-the use that drives the distribution system cost.

One result of offsetting against the full retail price is that the price includes distribution system costs that may not be avoided. This is a shift in costs to other customers. As more costs are shifted to fewer remaining customers each remaining customer is burdened with a greater portion of the distribution costs. The result is price increases and greater financial incentive to also shift the remaining customer's portion to others. There is empirical evidence that this phenomenon can create a downward spiraling effect of revenues for the utility as solar penetration increases.[4] Because the system cannot remain functional without the distribution system, the DG customers must contribute to costs.

Payment at the retail rate that is significantly higher than generation costs creates an incentive for the customer to size the system not to meet the customer's needs but instead size the system based on up-front costs and physical ability to locate the renewable resource equipment and its balance of system[5] ("BoS"). To offset this scenario, Utah Code Ann. § 54-15-104 provides that excess generation expires at the end of the annualized billing period. The Company needs a mechanism to recover the costs associated with the credited generation created by the net metering program that is structured to account for the benefits the generation provides as well. This could be in the form of different mechanisms (e.g. fixed facility charge as requested by the Company, lower reimbursement rate, etc.).

The Division does not disagree that roof top solar provides benefits to the utility, other rate payers, or society at large. However, some of these benefits provided by the renewable resource come with associated costs, both monetary and societal. PV panels, for example, are manufactured using various heavy and rare earth metals, hazardous chemicals and gasses and other materials in manufacturing facilities governed by EPA emission rules in the United States. The panels have a useful life requiring them to be disposed of either through recycling or under EPA hazardous waste rules.[6] This does not include the different technologies for energy storage

[4] See Hawaii Electric http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Hawaiian-Electric-Companies-propose-plan-to-sustainably-increase-rooftop-solar
[5] Balance of System is everything besides the solar panels and inverters required to connect the system to the Grid.
[6] http://www.firstsolar.com/~/media/documents/sustainability/emissions_from_pv_lifecycle_na_wb.ashx. Also see http://web.mit.edu/2.813/www/readings/esandtPV2008.pdf

that might make intermittent renewable resources more like base load generation, but this topic is outside the scope of this docket. The point is that there are both costs and benefits, which must be netted. Even with that netting, however, it is important that net metering rates and compensation be structured to allow reasonably accurate and undistorted recoveries and incentives. Societal benefits are not easily valued and when attempts are made to value them, the results vary over a wide range and create a great deal of controversy. This is because the valuations require inference upon inferences based on the general population's willingness to pay or willingness to accept the costs to provide the benefit.

Additionally, net metering customers benefit from the grid in many ways including power that is voltage, amperage, reactive and frequency controlled, back-up power during non or low production times and start-up amperage for large electric motors and other equipment for which the net metering system is insufficient. In essence, the grid also acts as storage during excess generation periods. Without the grid connection, the solar PV customer would be left with a less reliable, more expensive and less productive electricity supply.

Specific Responses

In response to the Commission's request for initial comments in this docket, the Division addresses each of the four areas about which the Commission has requested comment. First, the Division believes the use of the approved DSM cost tests mentioned above may be helpful in measuring impacts, but potentially significant modifications will likely be required to reflect the unique profile of most net metering systems and customers.[7] These cost models are based on the California Standard Practice Manual ("SPM").[8] The Division believes through the ensuing technical conferences that the parties can propose and hopefully agree to input modifications as necessary to make these models capture the unique costs and benefits associated with the net metering program, which differs from DSM. The benefit component of the models should be in

[7] See CPUC October 28, 2013 study "California Net Energy Metering Ratepayer Impacts Evaluation" prepared by E3 - Energy + Environmental Economics. http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf. NPUC July 2014 study "Nevada Net Energy Metering Impacts Evaluation" prepared by E3. http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/ Announcements/ E3%20PUCN%20NEM%20Report%202014.pdf

[8] See October 2001 "California Standard Practice Manual-Economic Analysis of Demand-Side Programs and Projects"

terms of net benefits where applicable. The Division believes that the Societal input in the PacifiCorp Total Resource Cost Test ("PTRC") should be excluded as too difficult to determine on a system basis for various reasons. These include the extreme subjectivity of values, the dispersion of benefits, and the reality that many of the benefits of displacing fossil fuel emissions are not directly enjoyed by PacifiCorp customers because of the remoteness of many generation assets from customer loads. In the absence of specific legislation or much more measureable, concrete values, these considerations weigh against inclusion of imprecise and indeterminate social costs.

Second, the Division believes there may be other cost/benefit studies and models or ways to value solar but it has not had time to vet them. Every region requires unique inputs to the costs and benefits modeling. Some inputs and assumptions cross regions, others do not. The Division believes the ensuing analytical framework should be in its simplest form, consisting of inputs and processes where the data is obtainable, supportable, timely and easy to trend. A variety of measures may be helpful and choosing among them depends in large measure on the type of rate structure the Commission wishes to employ. If the Commission aims for a simple netting of average costs and benefits to be accomplished through one or two mechanisms (i.e. compensation rates and a fixed charge), a completely different set of tools might be employed than if the Commission wishes to create a completely new rate class with various components for residential net metering customers. This need for other studies and models becomes even greater if the Commission expands its study beyond residential net metering.

Third, as party to the ensuing technical conferences and construct of the analytical framework, the Division agrees that all models and processes should comply with statute and rule where applicable for the residential roof top solar and other residential customer-side generation net metering program. Exactly what that means remains to be seen given the statute's general commands. However, the Division believes that various approaches may be compliant with the statute. Given low levels of penetration within the system, data may not provide as much concrete information about theoretical costs and benefits as any party would like. Nevertheless, the Commission may exercise its discretion and rely on the available quantum and quality of evidence it receives to make a determination. A resulting tariff might be relatively

simple, yielding to a more robust tariff in future times when penetration increases, available data grows and better analysis is possible.

Fourth, the Division believes this docket should address the net metering program for residential customers only. Although similar, non-residential customer net metering programs could and do fall under different tariff structures. This docket is the result of a contested fixed facility charge for residential net metered customers. While Title 54, Chapter 15 does not, by its terms, apply to only residential customers, its capacity limits (Section 54-15-103(3)) represent a significant constraint on the program in the long-term. Given the recent docket's focus and the statutory limit, it seems wise to limit this docket's scope to residential customers.

Conclusion

Utility regulation is in transition. Originally, it was designed and modeled with the intent that energy flowed in one direction from the generator over transmission lines through substations to feeder circuits across distribution systems to customers both residential and non-residential. New technologies, including the solar PV systems that form the bulk of the current net metering program, change that flow and the relationship between customer and company.

DG creates challenges in the recovery of costs and compensation for benefits by the utility. With current rate structures, these challenges remain unsolved and shift costs and benefits between net metered and non-net metered customers. With change between rate cases, it can also leave utility companies undercompensated in certain ways.

The residential net metering tariff[9] structurally does not compensate the Company for costs associated with the grid. Some allege that it also does not compensate system owners for benefits but the Division is not yet persuaded of that fact. The Division will continue to reevaluate that position as evidence is presented. Nevertheless, even if those allegations are correct, the current rate structure does not efficiently capture those costs and benefits.

[9] See Schedule 6

This docket ought to determine the analytical framework and proper inputs to model relevant costs and benefits of residential net metering systems and customers to the utility. The model will have to protect the Company from a downward spiral associated with rates that do not collect enough fixed costs from those customers causing the costs. It must also properly compensate net metered customers for their generation without unfairly impacting other class rate payers. In short, this docket should result in identification of the relevant costs and benefits of residential net metering systems, attempt to accurately measure them, and establish a rate structure (if not actual rates) that generally collects fixed costs through fixed charges and fairly compensates net metering customers for the benefits they bring the system, which might not encompass all the value of the system to society generally or to the system owner.

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