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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

PREPARED REBUTTAL TESTIMONY OF

STEVEN S. MICHEL

ON BEHALF OF

WESTERN RESOURCE ADVOCATES

July 25, 2017

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven S. Michel. My business address is Western Resource Advocates, 409 East Palace Avenue, Unit 2, Santa Fe, New Mexico 87501.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Western Resource Advocates ("WRA"). WRA is a nonprofit conservation organization dedicated to protecting the land, air and water of the Interior West. WRA's Clean Energy Program develops and advocates policies to advance a Western electricity system that provides affordable and reliable energy, reduces economic risks, and protects the environment with expanded use of energy efficiency, renewable energy resources, and other clean energy technologies. WRA has offices in Salt Lake City, Utah; Boulder, Colorado; Carson City, Nevada; and Santa Fe, New Mexico. My role at WRA is to oversee our organization's energy policy development. In that role I supervise analysts, economists and others that, along with attorneys, appear before public utility commissions and in other forums, and advance WRA's energy policies in the interior Western United States.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Western Resource Advocates ("WRA").

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. In 1978 I graduated from Northwestern University with a Bachelor of Arts degree in Economics and History. I received Master of Business Administration and Doctor of

Jurisprudence degrees from Vanderbilt University in 1982. I have been involved in utility regulation for over thirty years, working on behalf of consumer interests, environmental groups, tribes and electric and gas utilities. I have provided testimony to, and/or appeared before, commissions in New Mexico, Arizona, Colorado, Utah and Nevada, as well as the New Mexico Environmental Improvement Board. I have been called as an expert numerous times before the New Mexico Legislature. I have drafted legislation and rules, some of which are now embodied in law, and have published several peer-reviewed papers addressing utility and environmental regulation in *the Electricity Journal*. Since 2004 I have co-chaired the Law Seminars International "Energy in the Southwest" conference, which is an annual two-day seminar presenting speakers from across the nation providing their expertise and perspectives on current energy and utility issues facing the Southwestern United States.

A more detailed description of my background is attached as Exhibit WRA____ (SSM-1).

Q. WHAT HAS PACIFICORP REQUESTED IN THIS PROCEEDING?

A. PacifiCorp has asked the Commission to approve Schedules 5 and 136 which together would establish a separate rate class, and new rates, for future residential rooftop solar ("solar DG") customers on its system. In its November 9, 2016 filing PacifiCorp described what it identifies as substantial, unsustainable, growth in net metering subscriptions among residential customers that it asserts is resulting in unacceptable subsidization of net metering customers by other residential ratepayers. According to the Company, approval of its requested rate relief, which includes a new rate class with demand charges for rooftop solar customers, would remedy the situation.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS CASE ON JUNE 8, 2017?

A. No, I did not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony submitted by the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), and several of the solar industry advocates on June 8, 2017. I will identify WRA's position on various recommendations of those parties, and provide my opinion on how those recommendations should be modified.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THESE TESTIMONIES.

A. I agree with the Division and Office that a transition period is appropriate as Utah moves away from net metering ("NEM"). However, rather than four groups of customers[1] as the Division recommends, or the multiple categories driven by an export credit that reduces over time as the Office and others suggest, there should be only three groups of customers: (1) existing NEM customers, (2) transitional customers and (3) future rooftop solar customers.

I agree with the Division that the current NEM program should end January 1, 2018 by capping the amount installed or applied for as of December 31, 2017.

I disagree with the Division that grandfathering of existing and transitional rooftop solar customers should end in 2025. While I agree that a relatively short period (e.g. 5 years) may be appropriate for the transition, this is a separate issue from the term over which an export credit should be preserved for transition customers.

[1] In this testimony, "customer" means a metered service rather than an individual or business.

I agree that there should be a docket that establishes an export credit and term for future (post-transition) rooftop solar customers. I do not agree with the recommendation for monthly netting as opposed to hourly. Rather, the Office's proposed hourly measurement for solar DG customers makes sense for charging and crediting solar DG customers. I disagree with the Office's suggestion that the reconciliations could be more frequent than hourly.

It is reasonable for the Commission to reserve judgment, until an export credit docket is concluded, on the term for which future (as opposed to transition) solar DG customers would be able to preserve their export credit. I do not agree with the Division that "lost revenues" should be a consideration in establishing an export credit for future solar DG customers.

Although I generally agree with the Office's recommendation that rooftop solar customers be required to take service under a time-of-use ("TOU") rate, I believe that recommendation is premature. While a well-designed TOU makes sense for these customers, I cannot not recommend such a requirement without knowing specifically what the future TOU rate will be, and how it will be designed.

I do not share the Division's view that either a separate rate class or a demand charge should be implemented as an outcome of this proceeding. Rooftop solar customers should not be segregated from other residential customers and a residential demand charge, in my opinion, is poor public policy.

Q. IF THE COMMISSION AGREES WITH YOUR REBUTTAL POSITION, WHAT DOES THAT MEAN FOR THE PROPER APPROACH TO ROOFTOP SOLAR DEVELOPMENT IN UTAH?

A. First, there would be three groups of rooftop solar customers instead of the four recommended by the Division: (1) statutory NEM customers, (2) transition customers, and (3) future solar DG customers. The statutory NEM program would be closed January 1, 2018 by adjusting the Commission-set statutory cap to the level of installations and final applications submitted prior to that date. NEM customers would be "grandfathered" and continue under the monthly net metering program until December 31, 2034, or 17 years from when the program ends.

A second group, transition customers, would be those that apply for or install their systems between January 1, 2018 and December 31, 2022 (i.e. five years). However, the export credit in place for transition customers would apply to their usage and exports until December 31, 2034, which is 12 to 17 years, depending on when their system is installed. This end date is the same as that for NEM customer grandfathering.

Unless adjusted to moderate or accelerate the pace of new system installations, a single export credit of $0.09/KWh would be available for transition customers until the end of the transition period. To avoid a potential incentive to oversize a system, any credit value remaining on March 31st of each year should be extinguished.

To assure that possible cross-subsidies during the transition are limited, there should be a *soft* cap of 250 MW of transition period installations, or 50 MW per year. A soft cap would be protected by periodic adjustments to the export credit rather than by halts to development. If installations in a year are outside of a 40-60 MW band, the export credit for new customers would be adjusted up (<40 MW) or down (> 60 MW) by $0.02/KWh, and would apply to these customers through 12/31/34.

To move from the transition to the future, the Commission should establish a docket to set an export credit and term. That docket would be opened in 2020 and conclude by the end of the transition in 2023. That docket would establish an export credit going forward, and the term for which that credit would apply. The docket would be informed by load data from the transition customers, who must have hourly metering capability and must agree to have their load data collected in order to be eligible for an export credit. In that export credit docket, the considerations identified by the Division to establish an export credit, except for "lost revenues," should be included.

To provide some certainty for the solar DG market, the Commission should indicate now that separation of rooftop solar customers into another rate class, or a demand charge for any residential customers, is not in the public interest.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I have organized my rebuttal by topic rather than by the party I am rebutting. At the conclusion of my testimony I provide the Commission with a summary of the issues in this case, and how WRA believes they should be resolved based upon this rebuttal testimony. The topics covered in my rebuttal testimony are:

1) *Net Metering End Date*
2) *Classification of Customers*

3) *Transition Period*

4) *Grandfathering and Certainty for Solar DG Customers*

5) *Export Credit for Transition Customers*

6) *Cap on Transition Customer Installations*

7) *Export Credit for Future Solar DG Customers*

8) *Time-of-Use Rates for Solar DG Customers*

9) *Separate Rate Class and Residential Demand Charge*

10) *Recommended Outcome Summary*

<u>NET METERING END DATE</u>

Q. THE DIVISION HAS RECOMMENDED ENDING THE CURRENT NET METERING PROGRAM ON JANUARY 1, 2018. DO YOU AGREE?

A. Yes. Utah's net metering statute contemplates that monthly netting would continue to be available to customers until a certain capacity level of installation, set by the Commission, is achieved. Currently, that level is 20% of PacifiCorp's 2007 peak. In addition, it seems that statutory net metering customers can preserve their status indefinitely.

In transitioning from the existing net metering regime to a new protocol, I agree with the Division that the current statutory net metering program should be capped at the level of applications accepted before January 1, 2018. I agree with the Office that future solar DG customers should have their usage and exports measured hourly, with those hours where production exceeds consumption compensated by an export credit. In those hours where usage exceeds production, the customer would pay the retail rate for the net consumption measured at the meter.

CLASSIFICATION OF CUSTOMERS

Q. THE DIVISION HAS RECOMMENDED HAVING FOUR GROUPS OF CUSTOMERS AS THE COMMISSION DEVELOPS A TRANSITION PLAN FOR SOLAR DG. DO YOU AGREE WITH THE DIVISION'S RECOMMENDATION?

A. The Division's recommendation assumes that a general rate case would create two groups of transition customers: those with applications prior to the outcome, and those after. The rate case would establish export compensation. I generally agree with the categories the Division recommends, however, only one group of transition customers is needed.

The compensation for excess solar DG energy which the Division suggests be decided in a rate case, I believe, can be decided now and should be set at the $0.09/KWh level suggested by the Office for a five year transition. In that vein, it is important to distinguish between electric rates, which the Commission routinely sets in rate cases based upon a cost of service, and what I refer to as an export credit, which is compensation that solar DG customers would receive for their excess generation for some fixed period of time. The export credit is similar to the price and term of a purchased power contract, rather than an electric rate. An export credit need not be set in a general rate case.

Because an export credit can be set now, and need not be revised until a proceeding concludes at the end of the transition period, there is only a need for three categories of customers: NEM customers, transition customers, and future solar DG customers.

TRANSITION PERIOD

Q. DO YOU AGREE WITH THE DIVISION'S RECOMMENDATION THAT THE TRANSITION PERIOD END IN 2025?

A. Yes and no. Contrary to the Division's recommendation that the transition period end in 2025, I would have it end three years earlier - 12/31/22. However, to protect the viability of the solar DG industry, transition customers should keep their export credit through 2034. I will discuss this further in the next section: "Grandfathering and Certainty for Solar DG Customers." If the Commission later decides that gradualism requires a longer than 2023 glide path for the solar DG industry, the Commission can address that gradualism in the export credit proceeding that would commence in 2020 and end 12/31/22.

GRANDFATHERING AND CERTAINTY FOR SOLAR DG CUSTOMERS

Q. WHAT EXACTLY DOES IT MEAN TO GRANDFATHER OR PROVIDE CERTAINTY TO NEM OR TRANSITIONAL SOLAR DG CUSTOMERS?

A. Existing and new rooftop solar customers should be able to rely upon the rate structure and export credit in place at the time of their installation commitment. For statutory net metering customers, this means the monthly netting and rollover provisions available to them today should be preserved. For transitional rooftop solar customers, they should likewise have a level of certainty about the economics of their decision to install solar facilities. For both NEM and transition customers, this means that during the period for which their arrangement is secured, they should not be assigned to a separate rate class, have a demand charge imposed, or otherwise be subject to structural rate changes that would significantly undermine the economics of their decision to install rooftop systems. For transitional customers, they should also be provided certainty for the export credit they will receive.

It is, however, important to distinguish the rate structure and export credit from the rate. The price which a rooftop solar customer pays for PacifiCorp's electricity will vary over time, and that is a variable that the customer understands. What should be preserved for these new customers is the structure of paying the prevailing rate for electricity they consume, measured hourly, and being compensated for excess hourly production at an export rate that is fixed for a reasonable period of time after their installation. This fixed period is consistent with the concept that an export credit is akin to a power purchase for a period of time, rather than an electric rate that is reset in rate cases.

Q. THE DIVISION RECOMMENDS THAT "GRANDFATHERING" OF EXISTING NET METERING OR TRANSITION CUSTOMERS END IN 2025. THE OFFICE RECOMMENDS 2030. WHY DO YOU DISAGREE WITH THOSE PROPOSALS?

A. I disagree with those recommended end dates because they are too long for a transition, but too short for the certainty that should be provided to net metering and transition customers. While net metering or transition program eligibility should end on 12/31/17 or 12/31/22, respectively, the net metering structure and the transitional export credit should be available to NEM and transition customers until 12/31/34. For transition customers that install their system by the end of the transition period (12/31/22), the credit would be secured for twelve years. A single end date for both NEM and transition grandfathering provides both an administratively simple and easy-to-understand conclusion to the NEM program and the transition. It also gradually reduces over time the compensation that transition customers can count on, which is also important for a smooth transition. Twelve to seventeen years is consistent with the payback periods that developers have indicated their systems can provide, which is important to assure that the outcome of this docket does not halt or severely impair rooftop solar development.

I disagree with the Office's and Division's proposed grandfathering periods for two primary reasons. The first is fairness. Net metering customers invested, and transition customers will invest, a substantial amount of money to develop their systems, and should justifiably be able to rely upon the economics of the then-existing regulatory regime. While I agree that transition customers should pay the prevailing rates for their net consumption of utility-supplied electricity, a new rate class or price structure in the near future for net metering or transition customers could dramatically compromise the economics of their investment. Such a dramatic change to the economics for these customers would be unfair and not in the public interest.

My second reason is to protect the viability of an industry important to Utah's economy and environment. Section 54-3-1 of the Utah Code recognizes "well-being of the State of Utah" as a consideration for the Commission's "just and reasonable" determinations. The development of distributed rooftop solar generation has provided strong economic development and jobs to Utah, which other witnesses have described. At the same time, to the extent that customers use zero emission resources such as solar power to serve their electricity needs, this provides environmental benefits to us all. If potential rooftop solar customers perceive that the economic basis for their investment could be radically changed and compromised in the near future, this would have a chilling effect on their willingness to invest in that technology, and would compromise the public interest benefits that rooftop solar development provides.

My opinion is that providing certainty through 2034 for the economic factors that inform NEM and transition customers to install their systems (i.e. the net metering structure or the level of export credit) would satisfy public interest concerns more effectively than the 2025 and 2030 dates recommended by the Division and Office. It is important to understand that, for the transition customers, regardless of how long their export credit is preserved, the retail rate and associated economics can change.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR POSITION ABOUT THE NEED FOR FAIRNESS AND ECONOMIC CERTAINTY WHEN CUSTOMERS MAKE LARGE INVESTMENTS?

A. Yes. In <u>Principles of Public Utility Rates</u>, Bonbright *et al.* discuss this issue in the context of the public interest. Referred to as the "Status Quo Criterion," the authors explain the need for fairness and certainty:

> To the extent that people have committed themselves to irrevocable, or inflexible and costly investment decisions, it is considered to be unfair to change the cost or price structure substantially because such changes inherently alter the wealth position of affected parties.

Bonbright at 74-5.

<u>EXPORT CREDIT FOR TRANSITION CUSTOMERS</u>

Q. WHAT IS AN EXPORT CREDIT?

A. An export credit is financial compensation for rooftop solar customers when their systems produce more electricity in an hour than they consume, and this excess electricity is exported to the utility for use by other customers. On a monthly bill, an export credit would offset the electricity charge for hours when the customer consumes more than their system produces.

Q. THE OFFICE RECOMMENDS THAT SOLAR DG CUSTOMER USAGE BE MEASURED HOURLY, OR MORE FREQUENTLY, AND SUGGESTS AN EXPORT CREDIT OF $0.09/KWH WHEN PRODUCTION EXCEEDS CONSUMPTION. SOLAR INDUSTRY REPRESENTATIVES RECOMMEND MONTHLY NETTING. WHAT IS YOUR OPINION ON THESE RECOMMENDATIONS?

A. I agree that an export credit is appropriate for transition and future rooftop solar customers. I also agree that usage and exports should be measured hourly and that $0.09/KWh is an appropriate initial rate for the transition. I disagree that measurement should be either monthly, as recommended by solar industry representatives, or more frequent than hourly, as suggested by the Office.

Unlike the Division's recommendation of an export credit set halfway between avoided cost and the average retail rate (approximately $0.067/KWh), I believe that gradualism concerns, and the testimony in this case about the substantial value of rooftop solar to Utah and PacifiCorp's system, suggest a higher interim credit. I agree with the Office that $0.09 cents per KWh could provide a reasonable transition export credit. To avoid a possible incentive to oversize a system, however, any credit value remaining on March 31st of each year should be foregone.

Q. WHY DO YOU BELIEVE AN HOURLY EXPORT CREDIT IS APPROPRIATE?

A. One of the concerns identified with the pattern of rooftop solar customer production and consumption has to do with the customer's reliance on utility infrastructure and service. This reliance occurs in those hours when the customer consumes utility-provided electricity because their rooftop system produces less than their needs, or in those hours that the customer exports power to the grid because the rooftop system produces more than is consumed. Net metering on a monthly basis does not recognize the diurnal pattern of production and consumption, and the hours of net consumption can be masked by other offsetting hours of net production.

While PacifiCorp's description of how a rooftop solar customer interacts with the utility's system hour-by-hour may be valid, a rooftop solar customer's consumption is the same type of usage as other residential customers, and should be billed under the same rates. The notable difference to the utility between rooftop solar customers and other residential customers is that a rooftop solar customer will at times export power. An appropriate compensation for that exported power is therefore warranted, and that compensation should be informed by the public interest and the important economic, environmental and electrical benefits that rooftop solar can provide.

Q. WHY DO YOU OPPOSE MEASUREMENT OF IMPORTS AND EXPORTS MORE FREQUENT THAN HOURLY?

A. There are two reasons. The first is that there is little data available to ascertain the impact that a more frequent than hourly reconciliation would have. The sparse load information we have today for PacifiCorp's system is hourly. Because there is little data, there is no basis to conclude that hourly measurement is not sufficient to fairly capture the economics of a rooftop solar customer's production and consumption patterns.

Second is that the standard for measurement in the electricity sector is hourly or longer. The industry commonly uses the terms "kilowatt-hour" or "megawatt-hour," not "kilowatt-minute." TOU rates and peak periods are all identified by the hour in which they occur. Power sale transactions are also typically made on an hourly or longer basis. To use a measured period of less than an hour would be difficult to administer and difficult for customers to understand.

Q. DO YOU AGREE WITH THE OFFICE'S SUGGESTION THAT $0.09/KWH IS AN APPROPRIATE INITIAL EXPORT CREDIT FOR TRANSITIONAL ROOFTOP SOLAR CUSTOMERS?

A. Yes. An export credit of $0.09/KWh is a moderate adjustment to the current monthly net metering system in place today. The transition from net metering to an export credit involves two fundamental changes to the current system – something that both customers and the solar industry will need to adjust to. Those changes are structural and economic.

The structural change would have solar DG customer usage reconciled hourly rather than monthly. This involves different meters and a different way of marketing for sellers used to explaining and understanding a monthly netting system. For customers, they will no longer be able to evaluate a system based solely on their energy consumption, but will now have to consider the times of usage and production. While that is an important and proper evolution for the rooftop solar business, it represents a significant change to how business is done, and should therefore be approached gradually.

The second change is economic. An hourly export credit equal to the retail rate a customer would otherwise pay for consumption would be economically equivalent to the current net metering system. Given the fundamental structural change that hourly measurement involves, my opinion is that the economic adjustment should be moderate during the transition. For that reason I support the Office's suggestion of a $0.09/KWh initial export credit, but disagree with the Division's proposal of approximately $0.067/KWh.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD AVOID A TRANSITIONAL EXPORT CREDIT THAT IS SUBSTANTIALLY LOWER THAN THE RETAIL ENERGY RATE?

A. Yes. I believe the Commission should also consider the economic and environmental benefits of having a viable, stable and sustainable distributed solar industry in Utah. Under-compensating rooftop solar customers could jeopardize the viability of the distributed solar industry in Utah. That would be contrary to the public interest and would violate the regulatory principle of gradualism. Keeping the export rate close to the current retail rate provides some continuity with current net metering practices and avoids disruption of Utah's solar industry. In addition, the threat to Utah's distributed solar industry from a lower export rate is exacerbated as we see solar tax credits diminish and disappear, and the possibility of import tariffs imposed on foreign solar panels.

The Commission should also recognize the testimony in this case on the value solar DG brings to PacifiCorp's system, which according to that testimony is substantial. While the Commission need not decide that value now, this testimony should cause the Commission to be conservative in making any adverse adjustments to the economics of rooftop solar. In sum, I do not believe the Commission should accept the Division's recommended $0.067/KWh export credit. Rather, any shift away from the prevailing energy rate for rooftop solar customer exports should be restrained. It is very important that the emerging distributed solar industry be protected as we go down the path of embracing new technologies that provide important public benefits.

Q. IS THERE INFORMATION IN THIS CASE THAT COULD PROVIDE THE COMMISSION A SENSE OF THE IMPACT OF A $0.09/KWH EXPORT CREDIT ON ROOFTOP SOLAR CUSTOMERS?

A. Yes, there is, although it relates to a very small sample size and I have not independently verified the information. Nevertheless, it appears credible and assuming I understand the data request and response that PacifiCorp provided, the Company's response to DPU 4.2-1 can provide the Commission with a sense of the impact of a $0.09/KWh export credit. That discovery response includes a spreadsheet attachment of a load study PacifiCorp conducted for six customers after solar DG was installed for them. That study shows the net amount each customer, after their rooftop solar installation, consumed or exported in each hour of the year. The customers varied in size and usage, and the total amount of exports during the year for all six customers was 17,769 KWh, or an average of 2,962 KWh/customer. That average matches up well with what PacifiCorp characterized in its response as its typical customer (Customer 106) who exported 2,923 KWh during the year, measured hourly. What this means for purposes of the initial $0.09/KWh export credit that the Office has suggested, and that I agree with, is that for a typical customer an export credit $0.01/KWh less than the retail rate would cost an additional $29.23 for the year.

<u>CAP ON TRANSITION INSTALLATIONS</u>

Q. THE OFFICE HAS PROPOSED A LIMIT ON DEVELOPMENT UNDER THE CURRENT NET METERING PROGRAM. DO YOU AGREE THAT THIS LIMIT OF ROUGHLY 10% OF THE 2007 PEAK IS APPROPRIATE?

A. The magnitude of the total cap recommended by the Office makes sense. However, I believe it should apply to net metering and transition customers, rather than only net metering customers. I say this because of my recommendation that all net metering be capped by the amount installed and applied for as of January 1, 2018 and that there be no transition customers that are monthly net metered. I worry that an extended net metering program beyond 2018 will create a rush to development before net metering ends, and an undesirable boom-bust cycle. Ending net metering entirely by 2018 will limit that cycle, particularly if it is accompanied by a moderate transition program.

That said, I agree that an additional 250 MW of development is an appropriate limit to the amount of additional rooftop solar that could be installed during the transition, or roughly 50 MW per year. This is consistent with total net metering and transitional development of about 10% of the 2007 peak. To the extent there is a cross-subsidy issue, this cap on development will assure that the impact remains minimal.

Q. HOW SHOULD THE COMMISSION ENFORCE THIS CAP?

A. I believe a *soft* cap, with an adjustable export credit, rather than a hard cap, makes the most sense. Halting development because a hard cap is reached would be economically disruptive. Instead, in March of each year, the Company should provide the Commission and parties with the amount of additional rooftop solar (residential and commercial) that was installed during the prior year. If the amount exceeds 60 MW, the export credit should be reduced by $0.02/KWh. If the amount installed is less than 40 MW, the export credit should increase by $0.02/KWh. These changes would apply only to future transition customers, not those that have already installed their systems.

EXPORT CREDIT FOR FUTURE SOLAR DG CUSTOMERS

Q. THE DIVISION HAS RECOMMENDED A LIST OF FACTORS THAT THE COMMISSION SHOULD USE TO ESTABLISH THE VALUE OF ROOFTOP SOLAR DEVELOPMENT. DO YOU AGREE WITH THE FACTORS IDENTIFIED BY THE DIVISION?

A. Generally I do, with one exception. The Division has identified what it believes the Commission should consider in determining the value of energy provided by rooftop solar customers. This value would inform the setting of an export credit and the term for which that credit would be secured. The factors identified by the Division were: program administration costs, integration costs, distribution costs, lost revenues, avoided energy costs, avoided transmission costs, avoided distribution costs, avoided line losses, and avoided environmental compliance. I agree that all of these factors and others, except for *lost revenues*, are appropriate for valuing solar exports and establishing an export credit. Lost revenues are not a cost to the system, and are not recoverable from other customers. They play no role in establishing a cost of service. Only costs and benefits should be considered in assigning a value to rooftop solar.

<u>TIME-OF-USE RATES FOR SOLAR DG CUSTOMERS</u>

Q. THE OFFICE HAS PROPOSED THAT ROOFTOP SOLAR CUSTOMERS BE REQUIRED TO SUBSCRIBE TO A TIME-OF-USE RATE THAT WOULD BE DEVELOPED FOR THE RESIDENTIAL CLASS. DO YOU AGREE WITH THAT RECOMMENDATIONS?

A. Not at this time, although I recognize that eventually a TOU rate could provide a good structure under which rooftop solar customers take service. The reason I say that is because a TOU rate could appropriately reflect that the value for consumed electricity and solar exports will vary at different times of day. The reason I do not share the Office's view that a TOU rate be mandatory is that, at this time, there is not a TOU rate in place for PacifiCorp's Utah customers other than a little-used experimental rate. Until a well-designed TOU rate is in place, I could not recommend assigning rooftop solar customers to it.

Q. PLEASE EXPLAIN HOW A TIME-OF-USE RATE, COUPLED WITH AN EXPORT CREDIT, COULD BE IMPLEMENTED AND WORK?

A. One concept would be that, in those hours that a system was exporting, the customer would be compensated at the prevailing TOU rate less, perhaps, an adjustment for the export, e.g. $0.01/KWh below the prevailing rate. To implement this, the Commission could allow or require rooftop solar customers to subscribe to a residential TOU rate available to all residential customers. A rooftop solar customer would be charged the prevailing rate in that hour, or compensated by the export credit, each hour depending on whether the customer was a net importer or exporter of electricity during that hour.

<u>SEPARATE RATE CLASS AND RESIDENTIAL DEMAND CHARGE</u>

Q. THE DIVISION HAS PROVIDED TESTIMONY THAT ASSIGNING A SEPARATE RATE CLASS TO ROOFTOP SOLAR CUSTOMERS "IS NOT UNREASONABLE." DO YOU AGREE?

A. No, I do not. The argument favoring a separate rate class for rooftop solar customers is based upon the premise that rooftop solar customers differ from other residential customers because they both import and export electricity, and require "stand-by" service for when their systems are not generating. An additional argument relates to rooftop solar customer usage peaking in the spring, whereas the peak for other customers occurs in the summer.

The differences between rooftop solar customers and other residential customers is not of a nature that supports a new rate class. One should not look behind the meter to decide how and what to charge various residential and small commercial customers. The rate a customer pays should be blind to whether a customer has a solar installation that reduces its demand, goes on vacation, or has controls to cycle its cooling loads. Whether customer-owned rooftop solar is producing during an hour, or an air conditioner is switched off in that same hour, can look exactly the same at the point of sale. Going beyond that, to look at why, rather than how, a customer's usage appears as it does, would create a slippery slope that would have each customer with its own unique rate. The same logic could be used to segregate customers with electric heating or water heating loads, electric hot tubs, vacation homes or refrigerated air conditioners, and argue that they too should be assigned separate rate treatment.

That type of distinction should be avoided. Residential rates should apply to all residential customers, commercial rates to commercial customers, and so on. The means by which a customer manages its usage should not trigger a different rate.

Q. THE DIVISION HAS ALSO TESTIFIED THAT PACIFICORP'S PROPOSAL FOR A RESIDENTIAL DEMAND CHARGE COULD BE COST JUSTIFIED, AND SHOULD BE CONSIDERED BY THE COMMISSION. DO YOU BELIEVE DEMAND CHARGES ARE APPROPRIATE FOR ANY RESIDENTIAL CUSTOMERS?

A. No, I do not. Traditionally, demand charges have been applied only to larger commercial and industrial customers. These types of customers are businesses that tend to be sophisticated electricity consumers, and often have an ability and motivation to adjust their usage because it can have a significant impact on their profitability. A demand charge is not appropriate for residential customers, and rooftop solar customers in particular.

Q. WHY NOT?

A. There are four reasons. First is that electricity demand, and demand charges, are difficult to understand. In my experience, even industry professionals sometimes confuse kilowatts and kilowatt-hours. I do not agree that a demand charge is something most residential customers will comprehend.

The second reason I recommend against a residential customer demand charge is that there is little these customers will be able to do to manage their usage. Insofar as a demand charge is intended to provide an actionable price signal, it will not do so. Even assuming the customer understands how a demand charge works, managing electricity use in a multi-person household would require each person to coordinate their usage with each other person. That is challenging at best, and one breach of that coordination can create a substantial demand charge penalty that is locked in for a month.

Third is that a demand charge can destroy the economics of rooftop solar installation. A rooftop solar customer whose system is not producing at a time of heavy consumption would experience a costly monthly charge that could wipe out much, if not all, of any economic benefit of self-generation. Put another way, not only would a rooftop system fail to pay for itself over any reasonable time period, but customers could suffer a substantial financial loss by their installation. The bottom line is that a demand charge on these customers would jeopardize the viability of the rooftop solar industry, and the many benefits it brings to Utah. I do not believe it is in the public interest to approve rates that could quash rooftop solar development, given my view that this technology has the potential to transform our electricity supply in a very good way.

Finally, I believe we must be cognizant of the likely transformation of our electricity supply and its costs over time – a transformation that could change how we perceive electricity. It is quite possible that in the future a utility's peak period may also be the time that power is cheapest to produce and deliver. Solar power, which correlates well with consumption in hotter climates, could be the least costly generation technology during peak hours, with savings that surpass any additional transmission and distribution costs. To impose peak demand charges on residential customers, when in the not too distant future we may want to encourage, rather than discourage, peak consumption would be short-sighted at best.

Q. SHOULD THE COMMISSION BE SKEPTICAL OF PACIFICORP'S JUSTIFICATION FOR A RESIDENTIAL DEMAND CHARGE?

A. I believe that it should. While PacifiCorp's proposals in this case are couched in terms of fixing a cross-subsidy issue among residential users, one would be naïve to assume that the proposals are not also motivated, at least in part, by the economic threat that self-generation imposes on the Company's financial well-being. Edison Electric Institute, the trade association that represents U.S. investor-owned electric utilities, has identified customer-owned rooftop solar as a "disruptive challenge" and a long-term threat to electric utility survival.

In the future, both public utilities and customer-owned distributed generation should have an important role in meeting consumer energy needs. The Commission's actions in this docket should be mindful of protecting that future. I believe the Commission, for its part, must carefully guard against an outcome that threatens the long-term viability of either the utility or the rooftop solar industry.

In order to provide reasonable economic assurance to potential rooftop solar customers, and to protect the viability of that industry, it is important that the Commission determine in this case that establishing a separate rate class for solar DG customers, or structurally changing residential rates through implementation of a demand charge, is not just and reasonable and is not in the public interest.

<u>RECOMMENDED OUTCOME SUMMARY</u>

Q. PLEASE SUMMARIZE WHAT THE OUTCOME OF THIS CASE WOULD BE IF THE COMMISSION AGREES WITH YOUR REBUTTAL TESTIMONY.

A. If the Commission agrees with my rebuttal testimony:

1) There would be three groups of solar DG customers: net metered, transition and future.

2) <u>Net metered:</u> Net metering would end on December 31, 2017 by setting the statutory cap for the program equal to the rooftop solar amount installed or applied for on that date. Net-metered customers would have net metering secured for them until 12/31/34.

3) <u>Transition:</u> Customers that submit a final application between 1/1/18 and 12/31/22 would be transition customers.

These customers would have their consumption measured hourly. In those hours when their systems exported power, they would be credited $0.09/KWh against their monthly bills. Transition customer credit balances would be zeroed out each March 31st. The export credit in effect when their application is final would be secured until 12/31/34.

Transition customers would only receive an export credit if they allowed collection and anonymous use of their hourly consumption and export data.

The transition export credit would be adjusted for new transition customers if installations in the prior year were not on pace to achieve 250 MW of new installation during the 1/1/18 - 1/1/23 transition period. Specifically, the export credit would be reduced by $0.02/KWh if installations exceeded 60 MW during the prior year, and would be increased by $0.02/KWh if installations were less than 40 MW in the prior year.

4) <u>Future:</u> A docket to establish an export credit and term for future rooftop solar customers would be opened 1/1/20 and concluded by the end of the transition period on 1/1/23 – after which new rooftop solar customers would be subject to the decision in that case.

Among the considerations to determine a solar DG export value are program administration costs, integration costs, distribution costs, avoided energy costs, avoided transmission costs, avoided distribution costs, avoided line losses and avoided environmental compliance costs.

5) The Commission would determine that a residential demand charge, or creating a separate rate class for solar DG customers, is not just and reasonable or in the public interest and should be rejected.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes