BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	)))	Docket No. 14-035-114 DPU Exhibit 1.0R

Rebuttal Testimony of

Artie Powell, Ph.D.

Division of Public Utilities

July 25, 2017

Q: WILL YOU PLEASE STATE YOUR NAME FOR THE RECORD?

A: My name is Artie Powell.

Q: HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A: Yes. On behalf of the Division of Public Utilities (Division), I filed direct testimony on June 8, 2017. In prior phases of this docket, I helped prepare the Division's position on the issues and filed surrebuttal testimony on September 29, 2015, explaining the Division's proposal on the cost/benefit analysis framework. I also filed testimony on certain Company proposals for net metering customers in the Company's last general rate case, Docket No. 13-035-184.

Q: WHAT IS THE PURPOSE OF THE DIVISION'S REBUTTAL TESTIMONY?

A: I will address a few remarks to EFCA witness Mr. Gilfenbaum's characterization of the Company's earnings and his representation of the value of solar. The Office of Consumer Services (Office) and the Division are sponsoring a joint proposal that closes the current NEM program and transitions new distributed generation customers to a new paradigm. I will explain the Division's support for the joint proposal and why it is in the public interest.

The Division's consultant, Mr. Stan Faryniarz, will address the following: Mr. Eliah Gilfenbaum's value of solar calculations and net metering program costs and benefits as they relate to utility-scale versus distributed generation; use of the Company's recently filed Integrated Resource Plan as a source to calculate net metering program costs and benefits; characterization of bill credits in the cost of service analysis; and price signals from time-based demand charges and time of use energy rates, as well as metering and other reforms that allow for accurate price signals

Ms. Myunghee Tuttle will respond to the Office of Consumer Services' witness Mr. Danny A.C. Martinez on the customer charge proposals.

There was a considerable amount of direct testimony filed by the intervening parties in this docket. The Division has not attempted to address every claim, issue, or proposal that the parties have offered. Rather, the Division has limited its rebuttal testimony to the major issues. Silence, therefore, on any issue should not be interpreted as either agreement or disagreement with another party.

Q: WILL YOU SUMMARIZE YOUR REBUTTAL TESTIMONY?

A: Yes. Mr. Gilfenbaum claims that in 2016 the Company over earned by approximately $49 million and that a rate case where the Company's revenues would be reset could alleviate any subsidy arising from net metering. I demonstrate that Mr. Gilfenbaum's comparison of unadjusted returns to authorized returns is incorrect, and that any rate case relief will not address the underlying subsidy problem. Mr. Gilfenbaum also claims that the value of distributed solar could be as high as 12.6 cents per kWh. Using his model, I demonstrate several shortcomings in his analysis, leading me to conclude that his model is not useful in determining the long run value of distributed generation.

Finally, the Office of Consumer Services (Office) and the Division are sponsoring a joint proposal that closes the current NEM program to new customers and transitions future distributed generation customers to a new paradigm or program. Briefly, under the joint proposal,

- A proceeding to determine compensation rates for excess generation would start as soon as practical after the Commission order in this phase, approximately September 2017.

- Existing NEM customers are defined as customers who interconnect before January 1, 2018. These customers will be grandfathered under the statutory NEM program for a defined period determined by the Commission. The joint proposal recommends 12 to 17 years, January 1, 2030 to January 1, 2035.

- Transitional distributed generation customers, Transitional Customers, are customers that interconnect either after December 31, 2017 but before the end of the compensation docket, or until filling a cap of 200 MW. Transitional Customers receive compensation for excess generation measured on 15-minute intervals at a certain $/kWh (based on customer class) fixed for a Commission determined period. The joint proposal recommends between 10 to 15 years, January 1, 2028 to January 1, 2033.

- Post-Transitional customers interconnect after the end of the compensation docket or after the transitional cap is met. Post-Transitional customers receive compensation for excess generation as determined in the compensation docket.

Other details are in DPU Exhibit 1.1R, Joint Exhibit.

Q: MR. ELIAH GILFENBAUM[1] CLAIMS THAT THE COMPANY, IN 2016, OVER-EARNED BY APPROXIMATELY $49.8 MILLION DOLLARS AND THAT, "THE CROSS-SUBSIDIZATION CURRENTLY BEING BORNE BY ALL RATEPAYERS IN UTAH COULD BE CURED BY THE COMPANY SIMPLY MAKING A GENERAL RATE CASE FILING TO READJUST AUTHORIZED REVENUES" (PAGES 4-5, LINES 85-87). DO YOU AGREE WITH MR. GILFENBAUM'S ASSEMENT AND CONCLUSION?

A: No. Mr. Gilfenbaum's assessment of the Company's earnings position is based on an incorrect comparison of two returns, the Utah unadjusted earned return on rate base (ROR) to the Company's Utah authorized ROR, from the Company's 2016 Results of Operations (ROO). Furthermore, whether the Company is overearning or not, simply filing a rate case to "adjust revenues" will not address the subsidy built into current rates and structures.

To derive the $49 million figure, Mr. Gilfenbaum multiplied the difference between the Company's unadjusted earned ROR, 8.370%, and the Company's authorized ROR, 7.565%, by the Company's unadjusted rate base, $6.2 billion:

$$\$0.049 = (8.370\% - 7.565\%) * \$6.2$$

However, the Company's authorized ROR is derived (set by the Commission) using adjusted test year information and data in a rate case. In other words, Mr. Gilfenbaum

[1] Witness for the Energy Freedom Coalition of America, EFCA.

compared an unadjusted return to an adjusted return, an apples to oranges comparison.[2]

Despite the shortcomings of Mr. Gilfenbaum's earnings analysis, if we assume that the Company's 2016 ROO shows that the Company over-earned[3], filing a rate case to adjust revenues does nothing to address the subsidy built into current rates and structures and the current net metering program (NEM).[4] Rates are temporary in nature and last between rate cases. The subsidy flowing to current NEM customers is a structural problem that will persist without Commission action. Additionally, grandfathering current NEM customers as proposed in some form by all parties, results in the NEM subsidy outlasting a rate case. Changing retail rates does little to protect residential customers from the long term impact of the NEM subsidy. Notably, the subsidy was first identified by the Company in the last general rate case, Docket No. 13-035-184, where the Company sought an increase in the level of rates to alleviate its perceived under-earnings position. Thus, unless there is a fundamental change in NEM or rate structures or both, the subsidy will persist.

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[2] More precisely, the unadjusted earned return is derived from unadjusted data, while the authorized return is set by the Commission considering adjusted test year data and other factors. Mr. Gilfenbaum's analysis also incorrectly multiplies the (adjusted) authorized return by the Company's unadjusted rate base.

[3] Division staff are in the process of reviewing the Company's 2016 ROO and, according to the Commission's approved schedule, will file comments and recommendations with the Commission in September 2017.

[4] The allocation of any reduction will depend on the source of the over-earnings. Therefore, even if the over-earning amount is greater than the subsidy, there is no guarantee that any subsequent reduction in rates for an individual schedule would (perfectly) match or offset the subsidy in that schedule.

Q: MR. GILFENBAUM ASSERTS THAT THE LONG-TERM VALUE OF NEM EXPORTS COULD BE 12.6 CENTS PER KWH OR HIGHER. HAVE YOU REVIEWED HIS ANALYSIS?

A: Yes, I have.

Q: DO YOU HAVE ANY COMMENTS ON MR. GILFENBAUM'S ANALYSIS?

A: Yes. The analysis is one-sided—Mr. Gilfenbaum includes only what he considers as long run benefits and no long run costs—and there appear to be several fundamental flaws in his model. Additionally, Mr. Gilfenbaum's value does not pass reality checks. Therefore, I recommend that the Commission give little or no weight to Mr. Gilfenbaum's valuation.

Q: WOULD YOU PLEASE EXPLAIN?

A: Yes. First, Mr. Gilfenbaum's valuation does not pass available reality checks. The average residential rate is approximately 10.3 cents per kWh.[5] However, the average retail rate is a fully embedded rate. Common sense suggests that the value of NEM exports would be closer to an avoided energy rate plus, perhaps, a few incidentals.

For example, current Schedule 37 avoided cost rates are below four cents per kWh for small baseload QFs (e.g., geothermal plants), which allow dispatching or load tracking. The rates for other non-dispatchable QFs are even lower. As an example, for tracking solar, the summer on-peak rate is 3.3 cents per kWh. (See Table 1 for further details).

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[5] The average rate was derived from data in Company witness Ms. Joelle Steward's work papers: Figure 5-Residential COS and Charges.

Table 1: Schedule 37 15-Year Levelized Prices

	On-Peak (¢/kWh)		Off-Peak (¢/kWh)	
	Winter	Summer	Winter	Summer
Base Load	3.253	3.657	2.385	2.397
Fixed Solar	2.738	3.144	2.290	2.300
Tracking Solar	2.875	3.281	2.290	2.300
Wind	2.627	3.030	2.316	2.328

Consider the Solar Subscriber Program Rider, Schedule 73. The current Solar Subscriber Generation Charge for residential customers is 7.7250 cents per kWh. However, this charge has three cost components[6]:

1. Solar Resource Cost;
2. Utility Generation Cost; and
3. Program Administration Costs, including:
    a. Administration;
    b. Marketing; and
    c. Billing.

For the application, the Company assumed the Solar Resource Cost would be 5.5 cents per kWh.[7] In other words, the Rider includes approximately 2.3 cents per kWh to help cover the program costs and utility generation costs. Similar costs should be deducted from any long-term valuation of distributed resources.

[6] See Paul Clements, Direct Testimony, Docket No. 15-035-61.

[7] Actual resource costs were lower than 5.5 cents per kWh.

Mr. Gilfenbaum's value of 12.6 cents per kWh is almost four times the current avoided cost for tracking solar (12.6/3.3); and approximately 2.3 times the resource cost in the Solar Subscriber Rider (12.6/5.5).[8] Distribution-level savings and other values are unlikely to make up the difference. Additionally, in Docket No. 17-035-40, the Company is seeking "to construct or acquire approximately 860 MW of new wind projects" that it argues will lower net power costs and produce renewable energy credits that once sold in the market can lead to lower costs for customers.[9] Compared to these known resource values, Mr. Gilfenbaum's long-term value of solar does not appear reasonable.

Second, by including both energy and capacity values in his analysis, I believe Mr. Gilfenbaum double counts future CO2 compliance costs. The IRP chooses a preferred portfolio as a least cost/risk portfolio of resources. When an incremental resource, such as distributed generation, displaces an IRP resource, the value of the risks (e.g., CO2 compliance costs) are already embedded in the value of the displaced resource. Adding an incremental amount for that risk would then double count the benefit of the incremental resource. The future CO2 compliance cost should be removed from Mr. Gilfenbaum's long-term value.

Third, Mr. Gilfenbaum calculates a base generation capacity value, which he then inflates by 13 percent for reserve margins and 5 percent for capacity degradation. In

[8] To avoid confidentiality entanglements, the comparison to the Solar Subscriber Rider uses the higher resource cost (5.5 cents per kWh) from the Company's initial application.

[9] Direct Testimony of Rick T. Link, Docket No. 17-035-40, June 30, 2017, p. 3, lines 46-53.

other words, Mr. Gilfenbaum is assuming that distributed generation can avoid such measures. Mr. Faryniarz discusses this issue in his rebuttal testimony concluding that it is doubtful whether distributed resources can avoid such requirements. The inflationary factors should be removed from Mr. Gilfenbaum's evaluation.

Finally, I find Mr. Gilfenbaum's method of estimating the values of transmission and distribution capacity costs fundamentally flawed. Using historical data for system peak load and costs for annual transmission[10] additions, Mr. Gilfenbaum constructs a regression equation:

$$y = a + bX + e$$

Where the dependent variable, y, is cumulative transmission addition costs, and the independent variable, X, is peak load growth. Mr. Gilfenbaum uses the slope estimate, b, $1,041 per kW, to derive a transmission capacity value. The R-square from Mr. Gilfenbaum's regression model is 0.74. In other words, the model explains 74 percent of the observed variation in the dependent variable. While the model fit appears adequate, a considerable amount of variation, 26 percent, is unexplained.

To see if the model's fit could be improved and further refine the slope estimate, I added a time-trend variable to Mr. Gilfenbaum's model. The impact on the model's fit was significant. The R-square increased from 0.74 to 0.97. However, the estimate of

[10] Mr. Gilfenbaum uses a similar method for distribution costs. I will present my analysis for transmission and distribution below.

the slope switched signs. Where Mr. Gilfenbaum's model yields $1,041 per kW, the model with a time-trend variable estimates the slope as **negative** $257 per Kw. Similar results were found when including a time-trend variable in Mr. Gilfenbaum's distribution capacity model. (See Table 2 for more details).

Table 2: Comparison of Regression Results

	TRANSMISSION	
	GILFENBAUM	DPU
R-Square	0.745	0.966
Slope	1,041	-257
P-Value	0.0000	0.1167
	DISTRIBUTION	
	GILFENBAUM	DPU
R-Square	0.831	0.996
Slope	976	-16
P-Value	0.0000	0.7405

Making these changes in Mr. Gilfenbaum's model decreases the long-term value of distributed generation from 12.6 cents per kWh to 6.1 cents per kWh.[11] (See Table 3: A Comparison of the Long-Term Value of Distributed Energy).

[11] The Division did not review other components—Energy, Line Losses, and base Generation Capacity—of Mr. Gilfenbaum's model and, at this time, takes no position on their validity. The Administration and Billing costs deducted here are those costs from the Solar Subscriber Program Rider Costs.

Table 3: A Comparison of the Long-Term Value of Distributed Energy

	Gilfenbaum	DPU
Energy	39.50	39.50
Losses	3.75	3.75
Future CO2 Compliance	2.92	0
Generation Capacity	32.36	**27.28**
Transmission Capacity	29.37	**-7.26**
Distribution Capacity	17.76	**-0.30**
Administration and Billing	NA	**-2.23**
Total Benefits	$125.66	$60.75

Q: IS IT YOUR CONCLUSION THAT THE LONG-TERM VALUE OF NEM EXPORTS IS 6.1 CENTS PER KWH?

A: No. From my review, I conclude that Mr. Gilfenbaum's model or method of long-term value is fundamentally flawed. Some benefits appear to be double counted and other components, avoided transmission and distribution capacity costs, are modeled incorrectly.[12] A closer review of other components of his model may yield similar conclusions. Also, Mr. Gilfenbaum's analysis does not include any costs, for example administration or billing costs. Therefore, I recommend that the Commission give little or no weight to Mr. Gilfenbaum's analysis of the long-term value of NEM exports.

[12] In the case of transmission capacity costs, Mr. Gilfenbaum appears to have constructed two variables, peak demand growth and cumulative transmission addition costs, that are positively correlated but have no causal relationship to one another. In other words, the two variables appear to be spuriously correlated. For a discussion of spurious correlation see, "Beware of Spurious Correlations," Harvard Business Review, June 2015. Online at, https://hbr.org/2015/06/beware-spurious-correlations.

Nevertheless, the Division-derived number likely is significantly closer to the actual value of the resource, particularly given its closer value to the Solar Subscriber and other amounts for recent actual resources.[13]

Q: WHAT IS THE DIVISION'S RECOMMENDATION FOR THE LONG-RUN EVALUATION OF EXCESS GENERATION FROM DISTRIBUTED GENERATION RESOURCES?

A: In direct testimony, the Division recommended that the Commission open a separate proceeding to determine the method (i.e., a model) for calculating the long-run compensation rate for excess generation from distributed generation.[14] The Joint Proposal also recommends initiating a separate docket to determine reasonable compensation rates for distributed generation upon completion of the current docket. Distributed generation customers' rates for imported energy would be established in a future rate case.

Q: PLEASE EXPLAIN THE DIVISION'S RESPONSE TO INTERVENING PARTIES' ARGUMENT CONCERNING THE COMPANY'S USE OF A SINGLE YEAR ANALYSIS FOR ITS CFCOS, ACOS, AND NEM BREAKOUT STUDIES.

A: Most of the intervenors argue in their direct testimony that the Company's CFCOS, ACOS, and NEM Breakout studies are flawed because the studies used only a single historical year (2015).[15] The Parties' conclude that the Company fails to recognize the

[13] The Division notes the Division-derived number here, $0.061, is very close to the Division's proposal in direct testimony to set a temporary compensation rate halfway between avoided cost and the average retail rate.

[14] Artie Powell, Direct Testimony, Docket No. 14-035-114, June 8, 2017, lines 105-108, lines 479-481, and Stan Faryniarz, Direct Testimony, lines 109-112.

[15] See, e.g., USEA Direct Testimony of Micah Stanley, p. 4, lines 61-63 and EFCA Direct Testimony of Eliah Gilfenbaum, p. 6, lines 117-119.

full benefits offered by net metering customers. However, the Company did precisely what it was ordered to do per the Commission's Order dated, November 10, 2015, in this same Docket No. 14-035-114:

> While our July Order made clear our discretion in rate setting is not relevant to the cost-benefit analysis the Legislature has tasked us to perform under Subsection One, the parties are correct to emphasize that, ultimately, the results of the Subsection One analysis will be used to design rates. The results of the Subsection One analysis must leave us well poised to "determine a just and reasonable charge, credit, or ratemaking structure" under Subsection Two. It is therefore, eminently sensible to rely on the same test period data employed to establish all customers' rates. We are persuaded that relying on the rate case test period is consistent with the Statute and will yield useful results in the rate setting context. [16]

Q: HAS THE COMMISSION PROVIDED GUIDANCE IN THIS DOCKET REGARDING THE REQUEST BY SOME OF THE PARTIES TO CONSIDER THE COMPANY'S IRP PROCESS AS A DETERMINATE OF NET METERING BENEFITS?

A: Yes. In its order on November 10, 2015, the Commission determined:

> We understand PacifiCorp forecasts distributed generation penetration in connection with preparing its integrated resource plan ("IRP") . . . By necessity, this process requires long-term forecasting of loads and the effect distributed generation and other energy sector developments may have on PacifiCorp's system. However, the Legislature has tasked us with evaluating the costs and benefits of net metering under Subsection One for the express purpose of determining "a just and reasonable charge, credit, or ratemaking

[16] Commission Order, November 10, 2015, Docket No. 14-035-114, In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, p., 8.

> structure" under Subsection Two. Projecting the existence or quantity of distributed generation ten or twenty years from now is not necessary for these purposes and we do not believe the Legislature intended us to do so. Therefore, we adopt the Division's, PacifiCorp's and the Office's recommendation to assess net metering impacts over the test period utilized in PacifiCorp's next general rate case and decline to adopt the Joint Parties' proposal.[17]

Division witness Mr. Stan Faryniarz, addresses the inappropriate use of past IRP cycles or the Company's current 2017 IRP, which has not been acknowledged by the Commission, as a determinate for the costs and benefits net metering may bring to the system.[18]

Q: IN DIRECT TESTIMONY, SOME INTERVENING PARTIES RECOMMEND THAT NEM CUSTOMERS SHOULD BE GRANDFATHERED FOR 20 OR MORE YEARS. WHAT IS THE DIVISION'S POSITION ON THIS ISSUE?

A: The Division recognizes that for practical reasons some grandfathering of existing NEM customers may be justified. For example, changing out large numbers of meters may require time in order to mitigate rate impacts. In direct testimony, I also quoted Professor Bonbright who indicates that both utility investors and utility customers make investments "assuming reasonable stability and predictability of electric service rates."[19]

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[17] Id., pages 14-15.

[18] Division witness Stan Faryniarz, DPU Exhibit 2.0 REB-COS, July 25, 2017.

[19] Artie Powell, Direct Testimony, Docket No. 14-035-114, June 8, 2017, lines 205-219.

However, in general, the Division does not believe that guarantees of cost recovery for either the Company[20] or ratepayers are in the public interest.

One primary concern the Division has with grandfathering existing or future NEM customers is the impact that this may have on future electric utility rates and on the state's economy. Therefore, the Division believes that if permitted, grandfathering should be limited both in scale and time to mitigate the potential impacts on utility rates and the state's economy.

Q: WOULD YOU EXPLAIN WHAT YOU MEAN BY LIMITING GRANDFATHERING IN BOTH SCALE AND TIME?

A: Yes. If the Commission allows grandfathering of NEM customers, then the scale—the total number of customers or the total MW—should be limited to mitigate the potential impacts on rates and risks for Non-NEM customers. Similarly, the length of time that these customers are grandfathered should be limited to a reasonable period.

Under the current NEM program, NEM customers are compensated for their excess generation at fully embedded rates. Each month, the NEM customer's excess generation for the billing cycle is banked and used to offset a future month's consumption. Since a large proportion of fixed costs are collected through volumetric rates, this process of crediting and banking puts upward pressure on electric rates.

[20] Generally speaking, a regulated utility is afforded only the opportunity of cost recover not a guarantee of recovery.

Since electricity is an input for all residents and businesses, higher electric prices may harm the state's economy.

In direct testimony, the Division sponsored several recommendations and changes to the NEM program to mitigate these potential impacts. Since direct testimony, the Division has had numerous discussions with other parties including the Office of Consumer Services (Office), and reviewed the direct testimony of intervening parties. As a result of these conversations and review, the Division is sponsoring a joint proposal with the Office. The Division believes that this joint proposal, which I discuss in more detail below, is in the public interest, balancing the Company's and solar customers' investment risks and assumptions while confining the total amount of subsidy and risk for other ratepayers.

Q: WILL YOU SUMMARIZE THE JOINT PROPOSAL SPONSERED BY THE OFFICE AND THE DIVISION?

A: Yes. The joint proposal will create three sets of customers: existing NEM customers; transitional distributed generation customers; and post-transition distributed generation customers. Under the joint proposal:

- A proceeding to determine compensation rates for excess generation would start as soon as practical after Commission order in this docket, approximately September 2017.

- Existing NEM customers are defined as customers who interconnect before January 1, 2018. These customers will be grandfathered under the statutory

NEM program for a defined period determined by the Commission. The joint proposal recommends 12 to 17 years, January 1, 2030 to January 1, 2035.

- Transitional distributed generation customers, Transitional Customers, are customers that interconnect either after December 31, 2017 but before the end of the compensation docket, or until filling a cap of 200 MW. Transitional Customers receive compensation for excess generation measured on 15-minute intervals at a certain $/kWh (based on customer class) fixed for a Commission determined period. The joint proposal recommends between 10 to 15 years, January 1, 2028 to January 1, 2033.
- Post-Transitional customers interconnect after the end of the compensation docket or after the transitional cap is met. Post-Transitional customers receive compensation for excess generation as determined in the compensation docket.

Other details are in DPU Exhibit 1.1R, Joint Exhibit.

Q: THE JOINT PROPOSAL GRANDFATHERS EXISTING NEM CUSTOMERS. WILL YOU EXPLAIN GRANDFATHERING IN THE CONTEXT OF THE JOINT PROPOSAL?

A: Existing NEM customers, those that interconnect before January 1, 2018, will remain on the statutory NEM program. In other words, the provisions of the current Schedule 135 would be maintained, including netting across the billing period and carrying over kWh credits, which expire annually coincident with the billing year (March for most customers). Additionally, these customers would remain in their current underlying customer class and be subject to changes in rates are applicable surcharges. However, they would not be subject to changes in rate design or charges that apply only to Transitional and Post-Transitional distributed generation customers. Other details, such as closing the NEM program prior to the end of the grandfathering period, are found in the Joint Exhibit, DPU 1.1R.

Q: THE JOINT PROPOSAL RECOMMENDS THAT CURRENT NET METERING CUSTOMERS BE GRANDFATHERED FOR 12 TO 17 YEARS. WILL YOU PLEASE EXPLAIN THE DIVISION'S SUPPORT FOR THIS PERIOD?

A: As I previously explained, one primary concern that the Division has with grandfathering existing or future NEM customers for long periods is the impact that this may have on future electric utility rates and on the state's economy. Every 10 MW grandfathered for 20 years causes, on a present value basis, an incremental cost of approximately $5 million.[21] To limit the exposure to the incremental costs of grandfathering, the Joint Proposal limits the scale and time for grandfathering.

The scale is limited by closing the NEM program to new customers as of December 31, 2017. Only those customers who have interconnected to the Company's system by that date will be grandfathered under the current statutory NEM program.

Using information from Navigant, the Division estimates the average payback period for a customer with rooftop solar is approximately 13 to 15 years, depending on the size of

[21] The difference between the average retail residential rate, 10.3 cents per kWh, and an avoided cost rate, 3.2 cents per kWh, multiplied by the excess generation from 10 MW of distributed generation over 20-years. The capacity factor is assumed to be 16%, a 50% coverage factor (i.e., 50% of generation is pushed to the grid), and a discount rate equal to the Company's weighted cost of capital.

the system.[22] Limiting the grandfathering period to 12 to 17 years recognizes the customer's investment. While protecting customers, such a period also likely reduces the solar industry's risk of non-payment and any legal risk from customers who might be dissatisfied with their system's changing economics.

Q: ARE TRANSITIONAL OR POST-TRANSITIONAL DISTRIBUTED GENERATION CUSTOMERS GRANDFATHERED?

A: No. However, Transitional Customers, those who interconnect after December 31, 2017 but before the end of the compensation docket, or before 200 MW of interconnected MW, whichever comes first, are paid a fixed compensation amount for a fixed period. The Joint Proposal recommends the period be between 10 to 15 years. The fixed compensation rate for each class is 95% of that class' average retail rate. For example, the average retail rate for residential Schedule 1 customers is 10.3 cents per kWh. The compensation rate for this class is then approximately 9.79 cents per kWh for the fixed period. Other details and compensation rates for Transitional Customers is found in the Joint Exhibit. Post-Transitional Customers would receive compensation as determined in a separate compensation docket.

Fixing compensation for transitional customers provides some level of stability for those customers and the solar industry while limiting the subsidy they receive. Given the proposed cap on the transitional group's size, this proposal limits risk to other

[22] PacifiCorp's 2017 IRP, Volume II, Appendix O – Private Generation Study, Navigant – Private Generation Long-Term Resource Assessment (2017-2036), Private Generation Market Penetration Methodology, page 2.

ratepayers while smoothing the transition away from the retail rate subsidy received by current NEM customers.

Both Transitional and Post-Transitional Customers will initially remain in their respective classes and receive compensation for their excess generation measured on 15-minute intervals. However, in the next general rate case these customers would potentially be subject to Commission ordered changes to rate design or charges.

Q: UNDER THE JOINT PROPOSAL, DO POST-TRANSITIONAL CUSTOMERS RECEIVE FIXED A FIXED COMPENSATION RATE FOR THEIR EXCESS GENREATION?

A: No. the compensation rate for Post-Transitional customers will be that rate determined in the separate compensation docket.

Q: WILL YOU PLEASE SUMMARIZE THE SEPARATE COMPENSATION DOCKET?

A: Yes. In direct testimony, I anticipated that a compensation docket would take approximately two years. My estimate was based loosely on the schedule for Schedule 38, Docket 12-035-100. Based on conversations with other parties since direct testimony, I estimate that a compensation docket could take approximately three years, with the first year dedicated to collecting additional data. Therefore, the Joint Proposal recommends that the Commission initiate the compensation docket immediately following the conclusion of this docket, perhaps as part of the final order in this docket.

Q: WHY IS THE JOINT PROPOSAL IN THE PUBLIC INTEREST?

A: The Joint Proposal confines the magnitude and risk of the subsidy from non-DG customers to DG customers without an abrupt shift to different rates and rate structures for customers who have taken advantage of a statutory and Commission-approved program. The proposal appropriately caps the statutory program and allows a transitional generation amount that permits continued development of distributed generation without perpetuating the existing subsidy beyond a reasonable size and time horizon. Significantly, the proposal also allows the Commission to begin moving away from the crude monthly netting tool used for NEM customers in the absence of a general rate case. In short, the Joint Proposal balances the public interest in good ratemaking, rate stability and accuracy, and fair apportionment of the cost of service.

Q: DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A: Yes.