Sophie Hayes (12546)
Utah Clean Energy
1014 2nd Ave.
Salt Lake City, UT 84103
801-363-4046
Attorney for Utah Clean Energy

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Review of Electric Service Schedule No. 38, Qualifying Facilities Procedures, and Other Related Procedural Issues	**DOCKET NO. 14-035-140** **Utah Clean Energy Exhibit 3.0**

Surrebuttal Testimony of Ken Dragoon
on behalf of
Utah Clean Energy

REDACTED

June 11, 2015

RESPECTFULLY SUBMITTED,
Utah Clean Energy

_____
Sophie Hayes
Counsel for Utah Clean Energy

INTRODUCTION

Q: Please state your name and business address.

A: My name is Ken Dragoon. My business address is 3519 NE 15th Avenue, #227, Portland, Oregon 97212.

Q: Are you the same Ken Dragoon who filed direct testimony on behalf of Utah Clean Energy in this matter on April 28, 2015 and rebuttal testimony on May 28, 2015?

A: Yes.

Q: What is the purpose of your surrebuttal testimony?

A: The purpose of my testimony is to respond to Mr. Peterson's rebuttal testimony on behalf of the Division of Public Utilities (DPU or Division), Mr. Hayet's rebuttal testimony on behalf of the Office of Consumer Services (Office or OCS) and Mr. Link's rebuttal testimony on behalf of Rocky Mountain Power (Company or RMP), collectively referred to herein as the Parties. My testimony here clarifies some mischaracterizations and misperceptions of my earlier direct and rebuttal testimony.

In their testimony, the parties focused on the incorrect hypothesis proffered by my earlier testimony regarding the origin of wintertime loss of load events and argued against positions *UCE did not take* regarding splitting the PacifiCorp system, excluding regions or time periods from the capacity contribution analysis, and making "arbitrary" changes to maintenance schedules. Rather than taking these position, my testimony sought, and continues to seek, explanations for unusual and potentially anomalous results from the PaR study

that neither NREL nor DPU investigated. Given that the PaR results are a key variable input into the capacity value calculation it is critical that we carefully analyze the PaR results.

PacifiCorp's capacity value calculations using the CFAM method rely on two main inputs: 1) the characterization of wind and solar resources, which is not disputed in this docket, and 2) the results from the PaR model. The results from the PaR analysis are a key variable input into the CFAM analysis and, as I've discussed in my direct and rebuttal testimony, these PaR results give the Company lower capacity values than other sunny, summer-peaking utilities. The Commission deserves a plausible explanation for these results.

If the Commission wants fair and accurate capacity values for wind and solar resources, then it is critical to carefully analyze and understand these PaR results before approving the output of the CFAM method. The fact the model calculates high numbers of loss of load events during relatively lower-load April and winter months, that the Company appears not to have counted all the loss of load events calculated by the model, and the as-yet unexplained reason the model shows significant loss of load events in Wyoming, all raise questions about the results that deserve a credible response. These questions should be answered before approving capacity values for wind and solar based upon these results.

In this surrebuttal testimony, I strive to clarify points from my direct and rebuttal testimony and to state UCE's recommendations to the Commission.

RESPONSE TO REBUTTAL TESTIMONY

Q: Please summarize the issues you will address in your rebuttal testimony.

A: Both the Company and DPU correctly observe that the hypothesis offered in my direct testimony, that the wintertime loss of load events were due to transmission constrained events occurring on the west side of PacifiCorp's system, proved to be incorrect. I agree that this was not the cause, as the model output data shows that nearly *all* of the wintertime loss of load events occurred in Northeast and Southwest Wyoming.

While my original hypothesis on the reason for wintertime loss of load events was wrong, the bigger question remains: has the PaR model correctly calculated those events? Mr. Hayet's rebuttal testimony shows that although PacifiCorp's total peak *loads* are approximately1,500 MW higher in July than they are in February, the number of February *loss of load events* is higher than in July. Somewhat alarmingly, this does not seem to concern any of the parties, despite the acknowledgement that the tool used to arrive at them is a "black box."

The purpose of our intervention in this matter is to understand whether and how it makes sense for the Company's summer-peaking, relatively sunny climate to have such relatively lower solar capacity values than other studies have concluded. Specifically, I address three broad issues raised in rebuttal:

1. Our direct testimony conjecture with respect to wintertime outages, and the need to better understand the Wyoming outages (loss of load event count & Wyoming issues).

2. The misperception of our testimony with respect to splitting PacifiCorp's system and excluding certain time periods.
3. The relative importance of April loss of load events and their effects on the calculation.

Wintertime Outages

Q: Why are winter outages a focus of your testimony?

A: Although the Office's testimony (Hayet at 183-184) refers to my apparent "desire to eliminate all wintertime loss of load events" from the capacity contribution analysis, my specific purpose was to illustrate the importance of the winter events to the capacity value calculation and to understand whether they were correctly calculated.

Thus, my direct testimony examined the effects of the wintertime loss of load events on the solar capacity value computation, and showed that winter loss of load events are the *proximate reason* for the Company's solar capacity value being lower than the calculations of solar capacity values from other summer-peaking systems with a good solar resource.

My direct testimony also raised questions about the derivation of the unexpected number of spring and winter loss of load events. For example, I could not reproduce the Company's *count* of the loss of load events. And I continue to struggle with why, if demand is greater in summer, the Company's analysis shows that loss of load events are greater in winter.

Q: Please respond to the Parties' contention that the wintertime loss of load events did not predominantly occur on the west side of PacifiCorp's system.

A: The Parties' rebuttal testimony argues that the model does not show a preponderance of low of load events on the west side. (Peterson at 93-109, 150-163; Hayet at 184-185, 196-196; Link at 133-145). I agree with their assessment that my original conjecture was not correct. As a result, the issues I raised about the appropriateness of the Company's application of CFAM to constrained systems (e.g., Link at 61-69) are not relevant unless transmission constraints to Wyoming are a major factor in the analysis.[1]

It is unclear whether transmission congestion is the cause of the wintertime loss of load events that occur predominantly in Northeast and Southwest Wyoming, as the Company has not provided transmission congestion data.[2]

[1] With regard to the relevance of transmission congestion in CFAM analysis: as I discussed in my direct testimony, CFAM was developed to compare the efficacy of renewable resources in meeting load compared with traditional resources. To wit, if a loss of load event could not be reduced by *a traditional resource* due to transmission congestion, it would not be accurate to reduce the capacity value of a renewable resource by including that loss of load event in the CFAM calculation. Logically, you would need to reduce the capacity value of all resources that are not able to meet load due to transmission constraints. My original proposition was to exclude specific loss of load events in the CFAM calculation that resulted from transmission congestion, not exclude specific regions, or time periods, or to split the PacifiCorp system, as I will discuss more below. If the bulk of the loss of load events arise in transmission constrained areas of the grid, the overall capacity value of renewables should not be penalized as no resource, fossil or otherwise, outside of a transmission constraint will have much value toward meeting load past the constraint.

[2] Utah Clean Energy has asked a series of data requests in an attempt to get to the bottom of this issue, and is currently awaiting answers to our fourth set.

Q: Does your admission that your conjecture about the cause of wintertime loss of load events being incorrect lend weight to the Company's analysis?

A: Not necessarily. In my view, the finding only deepens the mystery of the wintertime loss of load events. The purpose of the original conjecture was to construe a reason for the relatively high number of loss of load events in the *winter* for the Company's *summer* peaking system. The most likely cause that I could think turned out not to be the cause. As a result, the mystery has only deepened. Only the Office ventured an explanation for the result.

Q: What was the Office's explanation for the relative abundance of wintertime loss of load events?

A: Hayet's rebuttal testimony (at 201-215) offers the explanation that the Wyoming outages are due to the seasonal shape of Wyoming's load. Given that winter and summer peak loads are similarly high in Wyoming, he posits that it is reasonable to expect that the loss of load events in winter and summer would be roughly equal.

Q: Is that a reasonable explanation of the PaR results?

A: It is a difficult explanation to accept because the State of Wyoming contains many times as much generation as peak load. For there to be load in excess of generation in Wyoming, a significant fraction of Wyoming's generation would need to be out of service, causing shortages throughout PacifiCorp's entire system—not just in Wyoming.

Alternatively, it could be that transmission limits generation available in other parts of PacifiCorp's system from reaching the NE and SW Wyoming areas.

Q: What could be the cause of the PaR model output showing a preponderance of April and wintertime loss of load events occurring in Wyoming?

A: It isn't clear to me, but is likely embedded in the PaR modeling logic. In my opinion, the fact that the outages occur in *Wyoming* is likely due to PaR modeling logic or transmission constraints serving those areas of Wyoming. If the cause is transmission, the calculated solar capacity values are largely relevant only compared with conventional generation located in Wyoming. No resource, fossil or otherwise, that is outside of those areas would be able to address those loss of load events. This is simply a question of physics. Again, it is important to understand what is causing the loss of load events in order to validate the CFAM results.

Q: Is it important to understand the loss of load events in Wyoming when considering whether the CFAM analysis is accurate?

A: Yes, absolutely. A summary of the Company's responses to OCS data request 3.10-3 (parts 1-5) that I provided in my direct testimony shows 718 loss of load events in Northeast and Southwest Wyoming alone. As discussed in my direct and rebuttal testimony, the Company counts just 715 events in the CFAM analysis for the entirety of its system (Company workpaper "Hourly LOLP 2017.xlsx"). We don't yet understand why there appears to be a discrepancy between their workpaper and data request response.

Nearly half of the Wyoming loss of load events (295) occur in April and 87% (626 events) occurred between November and April (in the Northeast and Southwest areas of Wyoming). Given that the winter and spring events in

Wyoming appear to be the key events and inputs into the CFAM analysis, it is critical to understand the validity and applicability of these results if the desired outcome is an accurate capacity value.

Q: Do you know which of the 718 loss of load events that occurred in Wyoming are included in the CFAM analysis?

A: No. As discussed below, I could not match the number of events from the PaR model to the number of events used in the CFAM calculations, even after removing the Colorado events discussed in my rebuttal testimony.

Q: Is the issue with matching the Company's loss of load count related to the Colorado loss of load events?

A: Not directly. The Office argues (Hayet at 171-182) that the Company reasonably explained its logic for not counting the Colorado events. While I agree with that, my own count of remaining loss of load events, based on the Company's data response to OCS 3.10, is substantially higher than the Company's "Hourly LOLP 2017.xlsx" workpaper. The Company may have had reasons for eliminating other loss of load events—events outside of Colorado; however, despite data requests, this mismatch in the number of loss of load events remains.

Q: Are there other reasons to question the validity of the PaR wintertime loss of load results?

A: Perhaps the clearest illustration of the why the wintertime loss of load events merit closer scrutiny is in the Office's testimony (Hayet, Figure 1 at 191 and Figure 5 at 278). Figure 1 shows February loss of load events as

approximately equal to those in July, while Figure 5 shows that July loads are roughly 1,500 MW higher. All else being equal, the higher loads would be accompanied by higher numbers of loss of load events. While these results are not impossible, given that DPU approached the PaR analysis as a "black box" and NREL did not comment on the assumptions or results of the model, it is appropriate to seek an explanation for this result before blindly concluding that it is reasonable.

Splitting PacifiCorp's System and Excluding Time periods

Q: Does your testimony advocate splitting PacifiCorp's system and excluding specific time periods from the CFAM computation?

A: Contrary to the Parties' contention (Peterson at 129-130; Hayet at 311-312; Link 205-218), I did not intend to suggest that PacifiCorp's system be split for the purpose of this analysis or otherwise, nor to categorically exclude specific time periods. My original testimony suggested not counting loss of load events that occurred either because of transmission congestion, or other potentially errant artifacts of modeling (e.g., maintenance schedule assumptions).

The purpose of removing the winter and April loss of load events was intended to show the *effect* of those events on the calculated result. [redacted], not to argue for categorically excluding April from the analysis.

Maintenance Schedules

Q: Is it appropriate for the Company to consider changes to the modeled maintenance schedules?

A: The vehemence of the Parties' objection to any consideration of the assumptions relating to maintenance schedules (Peterson 68-73, 79-81, 81-83; Hayet 256-260, 264-296; Link 188-197) was very surprising to me. The Parties argue variously that the maintenance schedule is optimized to minimize ratepayer exposure to power costs; any change to the assumption would be arbitrary; changing the maintenance schedule would only move loss of load events to a different time period; and that there is no evidence to suggest changing the maintenance schedules would have any effect [redacted] loss of load events. I dispute each of these arguments, and affirm that each of them is incorrect.

Q: Why do you contend that the modeled maintenance schedule is not optimum?

A: Every year has a different maintenance schedule—for example some power plants only require major maintenance every two years. So the modeled schedule cannot be "optimized" for anything but 2017—certainly not for each of the years over which the Company will receive a capacity value from solar plants. So even if you believe that the maintenance schedule is optimized for 2017, it is certainly not optimized for any of the years during the resource deficiency period, long after 2017 is over.

The maintenance schedule is also not optimized for additional renewable resources for which this study will be used to evaluate. Furthermore, a casual

glance at the actual data would make most people question whether it is truly optimized, even for 2017. There are zero megawatts of maintenance planned [redacted] One must postulate an enormous and unrealistic power price differential between the [redacted] to believe that it is optimized based on price alone.

I understand that there are other factors to optimize over, but all of the east side maintenance begins exactly [redacted] Further, when you look at Figure 1, below, you see that [redacted] have [redacted] more outages than the remainder of the month and account for nearly a third of the April loss of load events. It is possible that staggering some of the shorter maintenance [redacted] could sharply reduce the [redacted] loss of load events.

Figure 1 demonstrates the sensitivity of the CFAM method to maintenance assumptions.

Figure 1.

Q: What evidence is there for your statement that moving

A: The largest loss of load . That strongly suggests that moving just a single generator's maintenance schedule assumption would be sufficient to reduce a significant number of the model's loss of load events.

Q: Isn't changing the maintenance schedule assumption arbitrary?

A: No. Spreading out maintenance a bit more reasonably is not nearly as arbitrary as

Q: Would moving the maintenance schedule cause the model to simply switch loss of load events from one month or time period to another?

A: [redacted]. Moving some of the maintenance from an overly-stressed maintenance month to a more surplus month would not increase the loss of load probability in the target month appreciably if the change is modest compared to the surplus. It is possible that there could be some additional loss of load events, but the loss of load events in [redacted] would register many, or even any, increase in events. In any case, this can be tested by rerunning the model with a modest maintenance schedule change.

Q: Would a change to the maintenance schedule increase replacement power costs?

A: First, it appears that moving the start of just one or two maintenance schedules from one [redacted] could be enough to avoid many of the loss of load events. So, in order to believe that changing the maintenance schedule would increase power costs, you need to believe that not only [redacted] power prices the lowest of the year, you must believe that prices [redacted]

[redacted], are the lowest of the year.[3] Second, if PacifiCorp does focus its east side maintenance [redacted] becomes short, as this study suggests, it could have the result of sending the market signals that could result in increased prices. Because prices tend to rise when shortages occur, causing a large shortage could send a sufficient market signal to cause prices to rise temporarily.

Recommendations

Q: Please summarize your recommendations for the Commission

A: The Parties conclude (Peterson 187-189, Link 13-15) that the result of the CFAM calculations is reasonable. Since DPU does not question the output or inputs of the PaR model, their conclusion hinges on an assessment that the Company's results are within a zone of reasonableness at levels of solar penetration near the expected level on PacifiCorp's system (Peterson direct at 179-183). However, the Company's testimony (Link at 234-236) states that their study assumed 579 MW of solar, which would produce less than 2% of PacifiCorp's *energy* load.

[redacted]

A more appropriate comparison of the Company's proposal is based on the 0-2% region of Figure 1, not the 5% level, as the chart that the DPU refers to *is based on energy, not capacity*. (Peterson Direct Figure 1 at 171 *et seq*).

The Company's results therefore fall out of the zone of reasonableness using the DPU's standard. I recommend a third party review of the PaR modeling assumptions and results before approving the Company's proposed solar capacity value. The Commission should not accept or approve the Company's solar capacity values until questions about the anomalous results of the PaR model and the applicability of certain PaR results from anomalous regions are addressed by a third party.

Q: Do you have any changes to the recommendation that you put forth in your rebuttal testimony?

A: Yes. In speaking with some of the parties it became clear to me that they were very concerned with the current capacity value for solar used in the avoided cost methodology. I recommend the following to address this concern: the Commission should revise its interim solar capacity values while anomalous PaR results are investigated. One option would be to assign solar capacity values that are half way between current values of 68% and 84% and the Company's proposed 34.1 and 39.1% until the third party analysis is completed.

Q: Does that conclude your testimony?

A: Yes.