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May 13, 2009

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UM 1355 – In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON Investigation into Forecasting Forced Outage Rates for Electric Generating Units.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Testimony.

/s/ Kay Barnes
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c: UM 1355 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UM 1355

STAFF REPLY TESTIMONY OF

Kelcey Brown

In the Matter of
THE PUBLIC UTILITY COMMISSION OF OREGON
Investigation into Forecasting Forced Outage Rates for Electric Generating Units.

May 13, 2009

CASE: UM 1355
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Reply Testimony

May 13, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME KELCEY BROWN THAT FILED OPENING TESTIMONY IN THIS PROCEEDING?

A. Yes. My Witness Qualification Statement can be found in Exhibit Staff/101, Brown/1.

Q. PLEASE PROVIDE A SUMMARY OF YOUR OPENING TESTIMONY.

A. In my opening testimony I discussed the following findings and recommendations:

(1) Absent finding a better predictor of the test period forced outage rate, I recommended the continued use of the four-year rolling-average methodology;

(2) I recommended that the Commission adopt a new set of formulas for calculating outage rates for power cost modeling;

(3) I recommended that the Commission adopt the NERC equivalent forced outage rate (demand) (EFORd) for gas-fired peaking facilities;

(4) I recommended that the Commission not adopt PacifiCorp's methodology for modeling forced outages at hydroelectric facilities;

(5) I recommended the use of an industry benchmark to determine the forced outage rate when the 4-year average methodology produces a rate that is unlikely to occur in the test year;

(6) and lastly, I recommended that the Commission require annual reporting of the estimated gross wind output at utility owned wind farms, in addition to the net output of the facility.

Q. PLEASE PROVIDE A SUMMARY OF YOUR REPLY TESTIMONY.

A. My reply testimony clarifies the outage formulas that I recommend the Commission require the utilities to use in their power cost models. In response to the parties opening testimony, I also provide further justification for my recommendations to:

(1) Use the EFORd formula for all gas-fired facilities

(2) Model different maintenance outage rates for heavy load hours (HLH) and light load hours (LLH);

(3) Use a four-year rolling-average methodology for including planned maintenance in utility power cost models;

(4) Eliminate forced outage rates from the modeling of hydroelectric facilities;

(5) Use an industry benchmark mechanism to adjust the forced outage rate if the 4-year average produces an outlier rate;

(6) Require detailed reporting of output and outages at utility wind generation facilities, and require the use of the competitively bid capacity factor for the first five years in the NVPC model; and

(7) Comment on CUB's position associated with increased reliability due to a new capital investment at the generation facility.

<u>NVPC Modeling Formula's</u>

Q. PLEASE DISCUSS THE OUTAGE RATE FORMULAS PROVIDED IN STAFF/100.

A. In my previous testimony, I provided three formulas: a planned outage rate, forced outage rate and a maintenance outage rate.

Q. DO YOU CONTINUE TO RECOMMEND THE USE OF THESE FORMULA'S FOR MODELING PURPOSES?

A. Yes, with minor modification. After reviewing the parties opening testimony and looking at the modeling application of the previous formulas, I have determined that a small modification to the proposed formulas for coal-fired facilities is warranted. I now propose that the following formulas be used:

$$\text{Planned Outage Factor (POF)} = \frac{POH}{PH}$$

$$\text{Forced Outage Rate (FOR)} = \frac{FOH + EFDH}{PH - POH - RSH}$$

$$\text{Maintenance Outage Rate (MOR)} = \frac{MOH + EMDH + EPDH}{PH - POH - FOH - EFDH - RSH}$$

Maintenance Outage Rate Heavy Load Hour (MOR_H)
Maintenance Outage Rate Light Load Hour (MOR_L)

POF = Planned outage factor. Using a four-year average, this will be used to determine the number of hours that the unit will be unavailable due to planned outages.
FOR = Forced outage rate. Using a four-year average, this rate will be used to derate the plant over the course of a year.
MOR = Maintenance outage rate. Using a four-year average, this rate will be used to further calculate a HLH/LLH maintenance outage rate split.
MOR_H = Maintenance outage rate heavy load hour. Using a four-year average of the utilities actual maintenance outages which occurred during HLH, this rate will be used to derate the plant during HLH.
MOR_L = Maintenance outage rate light load hour. Using a four-year average of the utilities actual maintenance outages which occurred during LLH, this rate will be used to derate the plant during LLH.
PH = Period hours are the total number of hours in a calendar year.

POH = Planned outage hours are the number of hours that a unit was unavailable due to annual planned maintenance. Planned outages are scheduled with a relatively long lead time, typically greater than one year in advance.
RSH = Total number of hours the unit was available for service but not electrically connected to the transmission system for economic reasons.
FOH = Forced outage hours are the number of hours that a unit was unavailable due to a forced outage event.
MOH = Maintenance outage hours are the number of hours that a unit was unavailable due to a maintenance outage. Maintenance outages are outages that are scheduled in a relatively short time frame, less than one year.
EFDH = Equivalent forced derated hours are equivalent to the time in hours of a full outage event, due to the unit realizing a reduction in capacity for a period of time, rather than a complete shutdown. There is no pre-planning for this type of outage event.
EMDH = Equivalent maintenance derated hours are equivalent to the time in hours of a full outage event, due to the unit realizing a reduction in capacity for a period of time, rather than a complete shutdown. This type of outage event will allow the unit operator to defer the derate.
EPDH = Equivalent planned derated hours are equivalent to the time in hours of a full outage event, due to the unit realizing a reduction in capacity for a period of time, rather than a complete shutdown. The planning period for these types of outages is longer than the EMDH. For modeling purposes it is more reasonable to include this in the calculation of MOR.

Q. DO THE PROPOSED OUTAGE FORMULAS REPRESENT A SIGNIFICANT DEVIATION FROM THE CURRENT METHODOLOGY?

A. No. The current forced outage rate formula is:

$$\text{Equivalent Forced Outage Rate (EFOR)} = \frac{FOH + EFDH + MOH + EMDH + EPDH}{PH - POH - RSH}$$

RSH = Reserve Shut Down Hours

The only difference between the current EFOR and Staff's proposed FOR and MOR calculation is that it takes into consideration the ability of the utility to schedule maintenance outages.

Q. HAVE YOU PROVIDED AN EXAMPLE OF HOW THESE OUTAGE FORMULAS WOULD BE CALCULATED AND APPLIED WITHIN THE UTILITIES POWER COST MODELS?

A. Yes. In Exhibit Staff/201, Brown/1, I assumed a 500 MW plant and a number of hours for each type of outage event. I then calculate the POF, FOR, and MOR; and provide an example of how they would be applied in the models.

Maintenance Outage Modeling

Q. DO YOU CONTINUE TO RECOMMED MODELING THE MAINTENANCE OUTAGE RATE ON A HEAVY LOAD AND LIGHT LOAD HOUR BASIS?

A. Yes. As previously discussed in Staff/100, I support a HLH/LLH split for modeling purposes. This will better reflect the actual operation of the utility to defer this type of outage event to specific times. Exhibit Staff/201 applies the FOR and MOR sequentially to achieve the desired result on a HLH/LLH basis.

Q. PLEASE DISCUSS THE RATIONALE FOR MODELING MAINTENANCE OUTAGES ON A HLH/LLH SPLIT.

A. As discussed in my previous testimony, Staff/100, Brown/11- 13, the utility is able to defer this type of an outage event and minimize the impact on variable power costs. PacifiCorp's response to Staff Data Request No. 5, shows that for coal plants only 43 percent of the maintenance outages occur during heavy load hours.[1] Since heavy load hours represent approximately 57 percent of the hours in a year, failure to account for the utility's ability to schedule repairs during light load hours results in a overstatement of modeled NVPC

Q. DO YOU BELIEVE THIS TYPE OF MODELING IS CONSISTENT WITH HOW THE UTILITY ACTUALLY OPERATES ITS UNITS?

A. Yes.

[1] *See* Exhibit Staff/103, Brown/1.

Modeling Forced Outages on a Gas-fired Facility

Q. DO YOU CONTINUE TO RECOMMEND THE USE OF THE NERC EQUIVALENT FORCED OUTAGE RATE DEMAND (EFORd) FORMULA FOR GAS-FIRED PEAKING FACILITIES?

A. Yes. Staff, CUB and ICNU support the use of EFORd for purposes of calculating the forced outage rate of a gas-fired peaking facility. In ICNU/100, Falkenberg/5-6, Mr. Falkenberg discussed specific examples of the types of errors that can occur when using the EFOR formula to calculate the forced outage rate of a gas-fired facility.

Q. DO YOU AGREE WITH MR. FALKENBERG, THAT THE EFORd FORMULA SHOULD BE USED FOR ALL GAS-FIRED FACILITIES, NOT JUST PEAKING FACILITIES?

A. Yes. Using PacifiCorp's Currant Creek unit as an example, Mr. Falkenberg persuasively argues that a forced outage hour is a forced outage hour regardless of whether the unit would have economically run during the hour. Failure to use the EFORd can significantly overstate the forced outage rate for purposes of power cost modeling. Therefore, I recommend that the Commission require the use of the NERC EFORd formula for calculating the forced outage rate of all gas-fired facilities.

Q. PLEASE RE-STATE YOUR RECOMMENDATION REGARDING THE MODELING OF MAINTENANCE AND PLANNED OUTAGES FOR GAS-FIRED PEAKING FACILITIES.

A. In the utilities' power cost models gas-fired peaking facilities should not be derated for maintenance outages or shown to be unavailable due to planned outages. On an actual basis, the utilities typically take this type of outage during times that the unit would not be called to run due to economic conditions. Therefore, reflecting this unavailability through a lower rated capacity of the unit in all hours of the year, and thereby increasing power costs is inconsistent with actual operations. For baseload and intermediate duty gas-fired facilities, (i.e., units that typically run greater than 60 percent of the year) it is reasonable to model maintenance and planned outages. However, I recommend that the modeling for these types of units proceed on a case-by-case basis using the historical and expected future operation of the unit to inform the modeling.

Four-Year Average of Planned Maintenance

Q. DO YOU CONTINUE TO SUPPORT THE USE OF A FOUR-YEAR ROLLING AVERAGE, VERSUS FORECASTING, FOR PLANNED OUTAGES?

A. Yes. Using the four-year rolling average planned outage factor will provide an accurate reflection of past practices and a normalized view of planned outages.

Q. IN THE CITIZENS UTILITY BOARD'S OPENING TESTIMONY, MR. JENKS DISCUSSES THE DIFFICULTY OF ACCURATELY FORECASTING THE LENGTH OF PLANNED OUTAGES (CUB/ 100, JENKS/9, LINES 11-12). DO YOU AGREE WITH MR. JENKS' ASSESSMENT?

A. Yes. Mr. Jenks provides an excellent example of the difficulty of accurately reflecting the length of a planned outage for the test period. I agree with Mr. Jenks assessment that the utilities will always be conservative when forecasting the time it will take to complete planned maintenance. That is, the utilities will tend to overestimate the amount of time required to complete planned maintenance. Forecasting the duration of planned maintenance is often case specific and is subject to the judgment of plant engineers and management. For all of these reasons, I recommend that a four-year rolling average of planned maintenance be used for test year ratemaking.

Benchmark Proposal

Q. PLEASE SUMMARIZE STAFF'S BENCHMARK PROPOSAL.

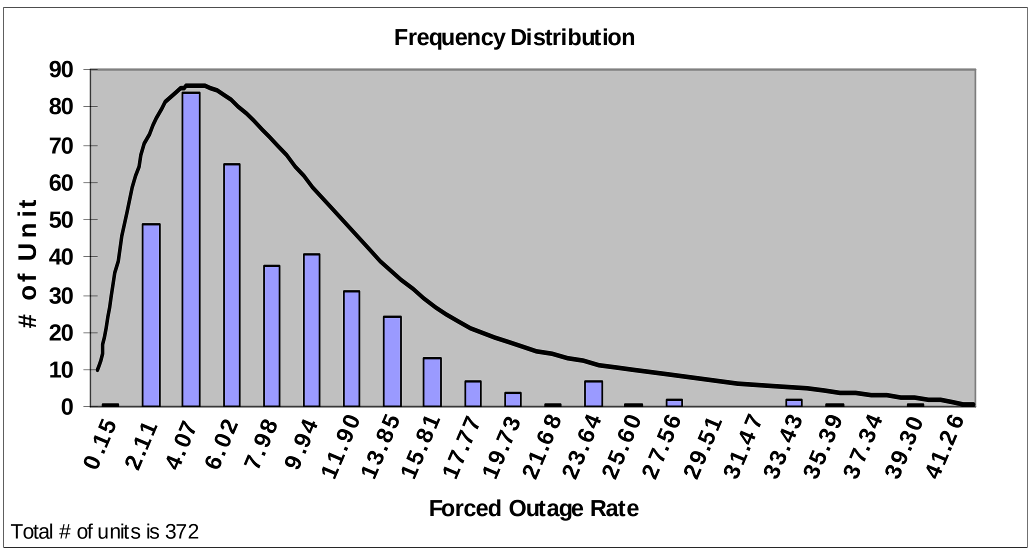
A. In Staff/100, Brown/18-21, Staff proposed a new benchmark methodology based on NERC outage rate information for like sized plants and fuel type. The purpose of the benchmark is to improve the predictive ability of the four-year rolling average.

Q. HOW DOES STAFF'S BENCHMARK PROPOSAL WORK?

A. The first step in the benchmark process is to calculate a units forced outage rate for the year using the methodology I recommended earlier in this testimony. The next step is to compare that calendar year forced outage rate to the NERC provided Industry data 90th and 10th percentile calculated values of forced outages for like sized plants and fuel type. If the unit's forced outage rate fell outside of the 90th or 10th percentile values, then the FOR would be adjusted to these 90th or 10th percentile values for that calendar year. The intent of this approach is to provide a more accurate forecast of what is likely to occur in the test year.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE DISTRIBUTION OF NERC FORCED OUTAGE DATA?

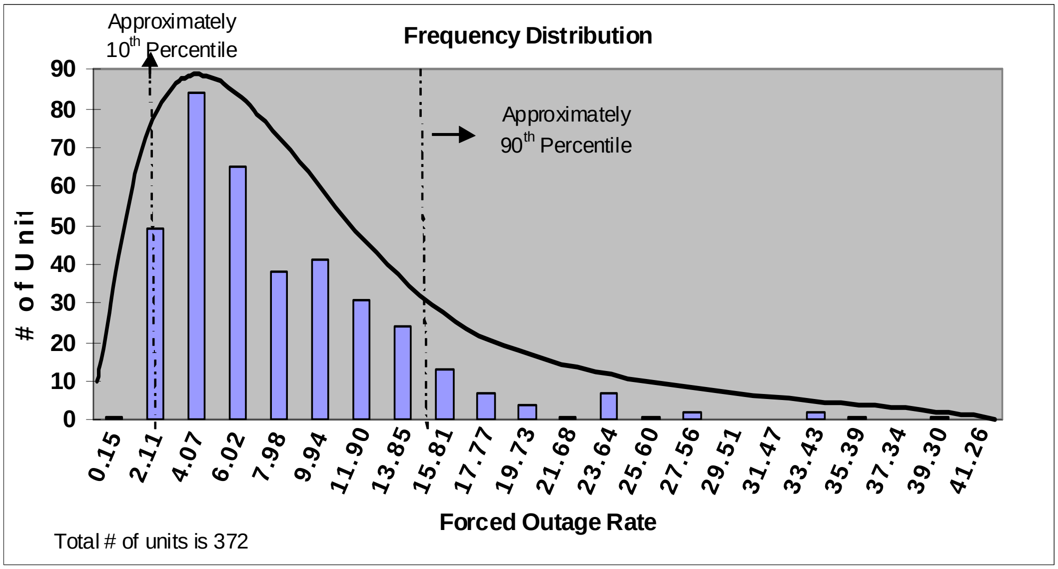
A. Yes. The following figure shows the discrete distribution of four-years worth of NERC data for coal-fired plants between 500-599 MW in size.



Each bar represents the number of units that reported a forced outage rate between the values on the x axis. For example, the graph shows that approximately 84 out of the 372 units over a four-year period had a forced outage rate of greater than 2.11 percent and less than or equal to 4.07 percent.

Q. WHAT DOES THE 90TH AND 10TH PERCENTILE VALUE MEAN?

A. In the following graph I have added lines labeled 90th and 10th percentile:



The values to the right of the 90th percentile line are approximately 37 of the reported 372 units, and similarly of the 10th percentile line. As you can see, the majority of the units fall between the 90th and 10th percentile, or approximately 298 of the 372 units reported a forced outage rate within this range.

Q. WHY IS IT REASONABLE TO USE INDUSTRY INFORMATION FOR THE BENCHMARK?

A. Using industry information for like-sized plants and fuel types is a reasonable comparison of whether the unit has incurred forced outages on a scale that is abnormal compared to all other industry units. Additionally, using greater than one years worth of industry data (four years in this example) provides a larger data set by which to calculate the 90th and 10th percentile values and is thus more statistically robust.

Q. IF THE FORCED OUTAGE RATE WAS GREATER THAN THE 90TH PERCENTILE VALUE AND WAS ADJUSTED AS YOU PROPOSE,

WOULD THE UTILITY NEED ADDITIONAL RECOVERY OF POWER COSTS?

A. No. The purpose of the four-year average, and the benchmark proposal, is to achieve a forecasted forced outage rate that is likely to occur in the test year. The forced outage rate is not a power cost recovery mechanism.

Q. HOW DOES YOUR BENCHMARK PROPOSAL ACHIEVE THE COMMISSION'S OBJECTIVE (STATED IN ORDER NO. 07-015) OF OBTAINING THE MOST ACCURATE FORECAST OF FORCED OUTAGES AT THE RELEVANT PLANTS?

A. In its Order No. 07-015 (UE 180), the Commission stated that it sought "…the most accurate forecast of forced outages at the relevant plants. "[2] Outliers, in statistical terms, should not be considered when attempting to accurately forecast a future time period. The benchmark proposal is an objective tool for the Commission to use in determining the level at which an event, or cumulative events in a calendar year, is unlikely to occur in a future period. Recognizing the years that a units forced outage rate would be considered an outlier, and adjusting the rate to a level that is more likely to occur (90th percentile), theoretically, will provide an improved forecasting ability to the four-year average over the long run.

Q. HAVE OTHER PARTIES IN THIS DOCKET PROPOSED SOLUTIONS IN CALCUALTING THE FOR IN THE CASE OF EXTREME EVENTS?

[2] *See* Order No. 07-015, page 14.

A. Yes. PGE's position is: "The deferral mechanism provides the Commission with the flexibility to make adjustments to the forced outage rate forecasts, when and, if needed." *See* PGE/100, Hager-Tinker/8, Lines 3-4. PGE goes on to state that: "The 4YRA methodology is flexible and can be adjusted to accommodate deferred accounting for extreme events and provides a reasonable base to measure variations against for use with a PCAM." *See* PGE/100, Hager-Tinker/8, Lines 17-19. As stated previously, the forced outage rate is not a power cost recovery mechanism, it is a forecast. In its current form, with the use of an unadjusted four-year average and a PCAM mechanism the possibility of over-recovery is significant.

Q. PLEASE PROVIDE AN EXAMPLE WHERE OVER-RECOVERY OF POWER COSTS MAY OCCUR IN THE SITUATION OF A PCAM MECHANISM AND AN UNADJUSTED FOUR-YEAR AVERAGE.

A. A PCAM mechanism allows the utility to re-coup higher, and refund lower, than forecasted net power costs (subject to an earnings review and the application of asymmetrical deadbands). Hypothetically, if a unit had an extreme outage event which caused power costs to be significantly higher than forecasted, after the earnings review, cost sharing and application of the deadbands, the additional power costs would be collected from customers in the following year. Additionally, the four-year average of forced outages would increase significantly, depending on the size of the extreme event, thereby causing an increase in net power costs for the following four test years. In this situation customers are burdened with higher costs in the following test year due to the PCAM mechanism and due to a higher forecasted forced outage rate.

Q. PLEASE DISCUSS THE CONCEPT OF OVER RECOVERY, OR “DOUBLE RECOVERY”, AS IT PERTAINS TO FORCED OUTAGE RATES.

A. In the past, parties have raised concerns associated with the concept of “double recovery,” where theoretically a utility could be compensated twice in the incidence of higher power costs associated with a forced outage event.

Q. WHAT PROCEDURAL OPTIONS ARE AVAILABLE TO THE UTILITY IF IT EXPERIENCES AN EXTREME OUTAGE EVENT?

A. If a utility experiences an extreme forced outage event it has several procedural options, it can seek deferral of the excessive costs associated with that event, it is captured in a power cost adjustment mechanism (PCAM), or it can choose to do nothing. In the case of the prolonged Boardman outage PGE sought a deferral mechanism for the excessive replacement power costs. As a result of PGE seeking a deferral mechanism, parties argued that it was inappropriate to also reflect this outage in the forced outage calculation. The prolonged outage would also cause power costs to be significantly higher in the test year due to the excessive deration of the unit. The solution at that time, and in other prolonged outage instances, was the removal of the deferred period from the forced outage calculation.

Q. DO YOU SUPPORT THE REMOVAL OF DEFFERED OR PROLONGED EVENTS?

A. No. In certain circumstances, removal of the outage period can have unintended consequences in the FOR calculation.

Q. PLEASE EXPLAIN THE UNINTENDED CONSEQUENCES THAT CAN OCCUR BY REMOVING AN EVENT FROM THE CALCULATION OF THE FOUR-YEAR AVERAGE.

A. By removing a period of time from the FOR calculation you then assume that the rate of forced outages that occurred during the rest of the time, by definition, occurred during that time period. For example, assuming an outage lasted six months of the year (8760 hours / 2 = 4380 hours), for which the utility sought deferral, and then subsequent to this outage there was an additional 30 day outage that occurred in the latter half of the year. Using the formula’s previously proposed in testimony; the forced outage rate for that year would be 16 percent with zero planned maintenance hours, i.e.

8760 hours /2= 4380 hours
30 days * 24 hours = 720 hours
720 hours / 4380 hours = 16.4%.

Q. WHAT ARE THE MODELED IMPLICATIONS OF A 16.4 PERCENT FORCED OUTAGE RATE IN THE TEST YEAR?

A. In the application of the 16.4 percent FOR in the power cost model it reflects a total of 1,440 hours of forced outages over the entire 8760 hour test year (8760 * .164 = 1,440). This is an example of where power costs would be significantly higher, due to the assumption that the 16.4 percent outage rate would also have occurred over the period that was omitted. Alternatively, if the utility experienced no forced outages for the rest of the period, this then assumes that the utility would not have experienced any forced outages over the omitted period, also reflecting an incorrect assumption.

Q. INSTEAD OF USING THE BENCHMARK APPROACH AT THE 90TH PERCENTILE LEVEL OR REMOVING THE EXTREME EVENTS FROM THE EQUATION, DO YOU PROPOSE ANY ALTERNATIVES?

A. Yes. As an alternative recommendation, if parties or the Commission did not believe that the 90th percentile adequately addressed concerns of over recovery, in the case of a deferral or a PCAM, another possible solution would be to use the mean, or average, of the industry information for the year in question. This would provide an objective replacement of the time period, rather than dealing with these instances on a case by case basis.

Q. HAVE YOU PROVIDED AN EXAMPLE OF A MEAN BENCHMARK APPLICATION VERSUS THE PROPOSED BENCHMARK AT THE 90TH PERCENTILE?

A. Yes. For illustrative purposes, please *see* Exhibit Staff/201, Brown/3.

Q. DO YOU BELIEVE THAT THE BENCHMARK MECHANISM MITIGATES THE ISSUE OF OVER, OR DOUBLE RECOVERY?

A. Yes. In addition to improving the accuracy of the four-year average, the benchmark proposal also provides mitigation to the issue of double recovery. However, if the Commission does not believe that the 90th percentile adjustment is adequate in addressing this concern, I propose the use of the mean of the industry information, rather than the removal of the event from the 48 month time period.

Hydroelectric Forced Outage Modeling

Q. PLEASE DISCUSS PACIFICORP'S FORCED OUTAGES MODELED ON ITS HYDROELECTRIC STORAGE FACILITIES.

A. PacifiCorp witness Mr. Mark Smith provided direct testimony associated with PacifiCorp's forced outage modeling on its hydroelectric facilities. *See* PPL/200, Smith/1-7. In testimony he states that "..the Company is modeling forced outages the same way as planned outages makes an unpredictable event predictable."[3] Mr. Smith goes on to speculate that the current modeling of forced outages is understated in the model.

Q. DO YOU AGREE WITH MR. SMITH, THAT FORCED OUTAGES ARE UNDERSTATED IN THE MODEL USING THE CURRENT METHODOLOGY?

A. No. PacifiCorp has not shown that in each recorded forced outage event the unit was required to spill water which resulted in lost energy at the facility. It is therefore my contention that this methodology is inherently overstating the impact of forced outages.

Q. DOES PACIFICORP'S FORCED OUTAGE RATE METHDOLOGY ON HYDRO CONTRADICT THE FACT THAT FORCED OUTAGES ARE INHERENTLY RANDOM EVENTS?

A. Yes. PacifiCorp's methodology models the resource as unavailable for specific time periods, similar to the modeling of planned outages, depending on

[3] *See* PPL/200, Smith/6, Lines 21-22.

the average number of hours in that month that were forced over the last four years.

Q. ARE THERMAL FACILITIES MODELED IN THE SAME WAY AS PACIFICORP HAS MODELED ITS HYDRO FACILITIES?

A. No. Forced outages occur randomly, and to appropriately reflect this in the model thermal facilities are derated for the entire year, so as not to model an inherent bias that may over or understate the potential financial impact in a given year.

Q. DOES PACIFICORPS METHODOLOGY CAUSE A DECREASE IN THE MODELED OUTPUT OF THE HYDROELECTRIC FACILITY?

A. Yes.

Q. IF PACIFICORP WERE ABLE TO SHOW THAT IT WAS REQUIRED TO SPILL WATER IN EVERY MODELED FORCED OUTAGE EVENT WOULD STAFF RECOMMEND PACIFICORP'S CURRENT METHODOLOGY?

A. No. PacifiCorp's current methodology is modeling an uncertain event with certainty, and therefore has the potential to significantly under or overstate the impact on net power costs. The subjective nature of the modeling will require additional due diligence on behalf of Staff and intervenors, and will always be subject to interpretation by each party.

Q. WHAT IS YOUR RECOMMONDATION IN REGARD TO PACIFICORP'S FORCED OUTAGE RATE MODELING OF ITS HYDRO FACILITIES?

A. Due to the fact that PacifiCorp has acknowledged that it is modeling forced outages in a way that is inconsistent with their occurrence, planned versus random, and it has not demonstrated, on an actual basis, lost generation due to the forced outage events, the Commission should require PacifiCorp to remove its forced outage rate modeling from the current TAM proceeding, UE 207.

Wind Facility Annual Reporting

Q. DO YOU CONTINUE TO SUPPORT ADDITIONAL WIND REPORTING REQUIREMENTS FOR THE UTILITY'S OWNED WIND FACILITES?

A. Yes. Hydroelectric forecasting takes into consideration what are called "water years," wherein the water conditions of the year are recorded and then used in long term averages in order to model a normalized hydro year for modeling purposes. It is this same forecasting methodology that needs to be developed or cultivated at the earliest possible time in order to have a basic understanding of the seasonality of wind and its impact on the regional utility owned wind farms. Therefore, I continue to support more detailed reporting of a utility owned wind farm, in addition to the net production of the facility.

Q. DO YOU AGREE WITH PACIFICORP'S WITNESS, MR. MARK TALLMAN, THAT ADDITIONAL REPORTING IS EXPENSIVE AND OVERLY BURDENSOME ON THE UTILITY?

A. No.

Q. DOES PACIFICORP CURRENTLY TRACK THE INFORMATION THAT YOU DISCUSSED IN STAFF/100, BROWN/27?

A. Yes. In Staff/100, Brown/25 I provided examples of the types of factors that can affect the output of a wind generation facility. This type of information is no more onerous than what PacifiCorp currently requires in its power purchase agreements (PPA). For example, in the instance of curtailment the PPA provider is required to provide what would have been the production of the facility given wind velocities at that time. The PPA provider is also required to maintain specific availability levels for certain terms of the agreement (e.g. 85%). If the provider were not maintaining these agreed upon terms of availability, PacifiCorp would need to be aware of the impact to net production. It is this type of information that I am requesting be provided to the Commission on an annual basis.

Q. WHY IS IT IMPORTANT TO UNDERSTAND THE OVERALL AVAILABILITY OF A WIND FARM?

A. The introduction of large scale wind farms has increased significantly over the past few years. Technology has also increased significantly over the last 10 years with respect to the turbines and blades that are being placed in these wind farms. Some of the consequences of these new technologies is that they are experiencing maintenance issues that have no historical basis. Therefore, it is important to understand what the impact of availability is on the total production of a wind farm, and how the seasonality of wind translates into net production.

Q. DO YOU AGREE WITH MR. JENKS, THAT THE CAPACITY FACTOR OF THE WIND FACILITY USED IN THE RFP OR DECISION MAKING PROCESS SHOULD BE USED IN THE NVPC MODEL FOR THE FIRST FIVE YEARS? (*SEE* CUB/100, JENKS/8)

A. Yes. Using the capacity factor (CF) from the competitive bid will have two positive benefits; (1) in the situation of a benchmark resource being chosen as the winning bid, it will provide an incentive to the utility to accurately project the CF of the facility, and (2) it will also provide an incentive to the utility to perform greater due diligence in investigating the reasonableness of the projected CF from bidders.

Q. HAS PACIFICORP PROPOSED A SIMILAR TIME FRAME, FIVE YEARS, FOR AN UPDATED TECHNICAL STUDY?

A. Yes. In PPL/300, Tallman/10, Mr. Tallman suggests that a five year period of time will provide enough information in re-modeling the resource, such that, on a modeled basis it will have lower variances from year-to-year going forward.

New Capital Investment

Q. WHAT IS YOUR RECOMMENDATION ASSOCIATED WITH MR. JENKS POSITION, THAT IN THE EVENT OF A NEW CAPITAL INVESTMENT, WHICH IMPROVES THE RELIABILTY OF THE FACILITY, THIS SHOULD BE REFLECTED IMMEDIATELY IN THE FORECASTED FORCED OUTAGE RATE? (*SEE* CUB/100, JENKS/7)

A. Staff recommends that the utility be required to provide an assessment of the impact to reliability for each new capital investment to a generation facility. With this information the Commission will then be able to determine whether it is appropriate to reflect this improved reliability within the forecasted FOR.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Exhibits in Support of
Reply Testimony

May 13, 2009

Using the following Formulas:			
POF =	POH/PH		
FOR =	FOH + EFDH/PH-POH		
MOR =	MOH + EMDH + EPDH/PH-POH-FOH-EFDH		
Coal-fired Facility	**4 Year Average**		**Occurrence**
(Example)	500 **MW**	Heavy Load Hour	45%
	8760 **PH**	Light Load Hour	55%
	400 **POH**		
	400 **FOH**		
	50 **EFDH**		
	200 **MOH**		
	50 **EMDH**		
	50 **EPDH**		
	POF =	400/8760 = 4.57%	
	FOR =	(400+50)/(8760-400) = 5.38%	
	MOR =	(200+50+50)/(8760-400-400-50) = 3.79%	
	MOR_L =	3.79% * Light Load Factor = 5.28%	
	MOR_H =	3.79% * Heavy Load Factor = 2.67%	
Modeled Capacity			
	= 500MW * (1- 5.38%) = 473 MW		
Heavy Load Hour Modeled Capacity	= 473MW *(1- 2.67%) = 460 MW capacity heavy load hours		
Light Load Hour Modeled Capacity	= 473MW * (1- 5.28%) = 448 MW capacity light load hours		

Benchmark Example: 90th and 10th Percentile

Using a four year data set, the calculated 90th percentile value is 14%
Using a four year data set, the calculated 10th percentile value is 2%

	Year 1	Year 2	Year 3	Year 4	4-Year Average	Benchmark Year 3	Benchmark 4-Year Average
MW	500	500	500	500	500	500	500
PH	8,760	8,760	8,760	8,760	8,760	8,760	8,760
POH	350	700	400	300	438	400	438
FOH	500	300	3,000	200	1,000	1,170	543
EFDH	50	50	50	50	50	0	38
MOH	200	250	50	100	150	50	150
EMDH	50	50	50	50	50	50	50
EPDH	50	50	50	50	50	50	50
POF	4.00%	7.99%	4.57%	3.42%	4.99%	4.57%	4.99%
FOR	6.54%	4.34%	36.48%	2.96%	12.62%	14.00%	6.97%
MOR	3.82%	4.54%	2.82%	2.44%	3.44%	2.09%	3.23%

Year 3 Adjustment
36.48 % would be adjusted to 14%
The number of forced outage hours would be calculated using the Benchmark rate, taking into account the POH =(8760-400)*.14 = 1,170

Benchmark Example: Alternative adjustment to the Mean

Using a four year data set, the mean calculation is 6%

	Year 1	Year 2	Year 3	Year 4	4-Year Average	Alternative Benchmark Year 3	Alternative Benchmark 4-Year Average
MW	500	500	500	500	500	500	500
PH	8,760	8,760	8,760	8,760	8,760	8,760	8,760
POH	350	700	400	300	438	400	438
FOH	500	300	3,000	200	1,000	502	375
EFDH	50	50	50	50	50	0	38
MOH	200	250	50	100	150	50	150
EMDH	50	50	50	50	50	50	50
EPDH	50	50	50	50	50	50	50
POF	4.00%	7.99%	4.57%	3.42%	4.99%	4.57%	4.99%
FOR	6.54%	4.34%	36.48%	2.96%	12.62%	6.00%	4.96%
MOR	3.82%	4.54%	2.82%	2.44%	3.44%	1.91%	3.16%

Year 3 Adjustment
36.48 % would be adjusted to 6%
The number of forced outage hours would be calculated using the Benchmark rate, taking into account the POH =(8760-400)*.06 = 502

CERTIFICATE OF SERVICE

UM 1355

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 13th day of May, 2009.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UM 1355
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