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May 13, 2009

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

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

Dear Filing Center:

Enclosed please find an original and five copies of the Confidential Reply Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. The confidential pages and exhibits are inserted in separate envelopes and sealed pursuant to the protective order in this proceeding. Also enclosed is a complete Redacted Version of the testimony.

ICNU is serving the confidential testimony and exhibits upon the parties who signed the protective order in this proceeding, with the exception of Idaho Power Company. The confidential information was originated by PacifiCorp, which ICNU understands has objected to the disclosure of any confidential information to Idaho Power Company pursuant to paragraph 11 of the protective order.

Thank you for your assistance.

Sincerely yours,

/s/ Irion A. Sanger
Irion A. Sanger

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Confidential Reply Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties who have signed the Protective Order in this docket (with the exception of Idaho Power Company), on the official service list shown below for UM 1355, via U.S. Mail. A Redacted Version of the testimony and exhibits was served via U.S. mail to parties which have not waived paper service, and via electronic mail to the entire service list.

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

/s/ Brendan E. Levenick
Brendan E. Levenick

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

In the Matter of	)
	)
The Public Utility Commission of Oregon	)
Investigation into Forecasting Outage Rates	)
For Electric Generating Units	)
	)

REPLY TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

May 13, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this case on April 7, 2009.

Q. WHAT IS THE PURPOSE OF THIS REPLY TESTIMONY?

A. I provide limited comments related to the direct testimony of other parties. I will also update the record concerning a discovery matter that was unresolved at the time I filed my direct testimony.

<u>Hydro Forced Outage Rates</u>

Q. AT PAGE 23 OF YOUR DIRECT TESTIMONY YOU DISCUSSED CERTAIN PROBLEMS RELATED TO PACIFICORP'S HYDRO FORCED OUTAGE RATE WORKPAPERS. HAVE YOU HAD ANY DISCUSSIONS WITH THE COMPANY RELATED TO THIS ISSUE SUBSEQUENT TO FILING YOUR TESTIMONY?

A. Yes. In my direct testimony, I pointed out that I was unable to replicate the data used by PacifiCorp for its hydro forced outage modeling based on the supporting information and instructions provided to the Industrial Customers of Northwest Utilities ("ICNU").[1/] After my direct testimony was filed I had a conference call with Mr. Mark Smith (the PacifiCorp witness whose testimony discusses hydro outage rates in this case) and others concerning these workpapers.[2/] During the discussions, my primary concerns related to the workpapers that were addressed. PacifiCorp provided a re-creation of the missing elements of its analysis, and the

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1/ In this instance PacifiCorp didn't provide complete workpapers, but instead provided supporting data and instruction on how to compute hydro forced outage rates. This is a rather unusual procedure, in my experience.

2/ This call was agreed to by PacifiCorp after a letter was written by counsel for ICNU to counsel for PacifiCorp pointing out the deficiencies the workpapers the Company provided.

reasons (principally missing data labels in the original submission) the results didn't match were discussed. A small discrepancy remains between the hydro forced outage data inputs supported by the workpapers and those used in power cost studies, but the discrepency is not substantial. As a result, I am satisfied now that PacifiCorp's workpapers support the number of hydro forced outage days it has proposed.

Q. DOES THIS MEAN YOU NOW ENDORSE THE PACIFICORP HYDRO FORCED OUTAGE MODELING?

A. No. Most of my original concerns remain, though I am no longer concerned that there are outright errors in the PacifiCorp inputs. However, other problems remain. For example, the method used to model such outages is premised on subjective assumptions regarding the distribution of hydro forced outages across time. I understand that the VISTA model, used to create hydro weekly energy in GRID, would not accommodate less than a full day outage, so modeling a fraction of a day (which might be the result if forced outages were properly being treated as random events) would have no effect in the model.

A further major problem is that PacifiCorp does not necessarily use the same four year period for hydro outages as it uses for other forced outages in the GRID studies.

Q. DOES PACIFICORP ACKNOWLEDGE PROBLEMS IN MODELING HYDRO FORCED OUTAGES?

A. Yes. Mr. Smith testified on page 7 that there is no industry standard for hydro forced outage modeling and that PacifiCorp is open to discussion related to methods to improve its hydro forced outage modeling. Mr. Smith also acknowledges that "[it] is very difficult to accurately model hydroelectric generator forced outages and related physical and financial impacts to production due to many variables including inflow volatility, operating requirements or other unpredictable circumstances." PPL/200, Smith/2-3.

Q. HOW IMPORTANT ARE HYDRO FORCED OUTAGES IN POWER COST MODELING?

A. Hydro forced outage modeling is important and the Company should seek to have the inputs as accurate as possible, however, other issues the Company's GRID model ignores are more important from a dollar standpoint. For example, in GRID, PacifiCorp uses a "peak shaving" algorithm for modeling hydro dispatch, rather than the more optimal "price shaping" technique that PGE applies in MONET. In this regard, it seems PacifiCorp has been quick to implement modeling changes that it believes will increase power costs, but does not wish to propose modeling changes that might reduce power costs.

The percentage of hydro market revenue (ΔHR) lost due to hydro forced outages can be approximated as follows:

$$\Delta HR = hfor*(1-P_r/P_d)$$

Here, P_d is the market price applicable to hydro generation in the most optimal dispatch (the desired price), P_r would be the price of the energy when it is later rescheduled (the rescheduled price) and *hfor* is the forced outage rate for the hydro unit. One can make some reasonable assumptions to determine a upper limit on the lost revenues by estimating the ratio of P_r/P_d. If the hydro forced outage resulted in rescheduling output from the HLH to LLH, the ratio of HLH to LLH market prices could be used to estimate the ratio. In reality this would probably overstate the impact of hydro forced outages, as some of the HLH energy may be rescheduled into HLH hours. Conversely, some hydro energy may already be being used in the LLH, so not much would be lost due to an outage. A typical value of the ratio of LLH to HLH prices for Mid Columbia is [redacted]. A typical value for hydro outage rates, *hfor* is [redacted]. Thus, the lost revenue due to hydro forced outages is on the order of 0.26%. Since the PacifiCorp methodology already accounts for lost revenue from run of river plants, this would be a very small percentage of the total hydro revenue. I believe this is a case where applying the method incorrectly may produce a far bigger error than the overall size of the problem.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission require PacifiCorp to remove its hydro forced outage modeling in the current TAM proceedings, but allow it to propose a different methodology in a future general rate case ("GRC"), or Transition Adjustment Mechanism ("TAM") (which is the functional equivalent of a GRC for power cost issues). The Company's hydro forced outage modeling is obviously a "work in progress" that apparently needs more time and work before being used in power cost studies.

Q. MR. GODFREY OF PACIFICORP PROPOSES A FORMULA FOR THE FORCED OUTAGE FACTOR TO BE USED FOR COAL PLANTS. DO YOU AGREE WITH HIS FORMULA?

A. No. Staff witness Kelcey Brown proposes to separate the maintenance outage and maintenance deration hours from forced outages in the computation of outage rates for power cost models. For the various reasons already discussed in my direct testimony, as well as that of Ms. Brown, I believe that deferrable maintenance outages and deration events should be modeled in a separate outage factor that is differentiated by HLH and LLH or weekend and weekday. I believe the Staff proposal accomplishes this quite well.

Q. HAS PACIFICORP PERFORMED ANY ANALYSIS THAT ADDRESSES THE ISSUE OF MODELING DEFERRABLE MAINTENANCE IN THE MANNER PROPOSED BY STAFF?

A. Yes. In a recent discovery response, PacifiCorp produced an analysis which it contends to show that there should not be a differentiation between on and off-peak outage rates. I've attached this analysis as ICNU/201.

The PacifiCorp analysis states that deferrable outages occur 48.3% of the time in the on-peak and 51.7% of the time in the off-peak. Because the standard deviation of the off-peak percentages is fairly high (13.3%), PacifiCorp states that the data is poorly grouped about the averages, and statistically suspect. For this reason, PacifiCorp states that given these results, it does not differentiate maintenance outages between on and off peak-periods. Id.

Q. DO YOU AGREE WITH THE CONCLUSIONS FROM THE PACIFICORP ANALYSIS?

A. No. My own analysis, as reported in my direct testimony, shows sound support for time differentiation of the maintenance outage rates. Further, this analysis performed by PacifiCorp is by its own admission "statistically suspect." ICNU/201. Indeed, the analysis doesn't even answer the correct question. The question the PacifiCorp study answers is this: "If one were to look at the results for a single unit, taken at random from the PacifiCorp fleet of generators, what percentage of its deferrable maintenance would occur in the on or off-peak, and how certain would one be of that result?" The answer is that for a single unit taken at random, its deferrable maintenance percentage would be 48%, but that one would have very little confidence for the ultimate value of that result.

The question we seek to answer is quite different. The relevant question is, if one were to look at the PacifiCorp fleet as a whole, on average is there a statistically significant tendency to schedule deferrable maintenance preferably to the off-peak? The answer to that question is a resounding yes. The reason is that for the sample of 51 generators, the sample standard deviation is not 13.3%, but <u>1.9%</u> (13.34% divided by the square root of 51, based on the Central Limit Theorem). If deferrable maintenance were scheduled at random, we'd see 44% of the deferrable outages occurring in the off-peak. Instead, we see 51.7% in the off-peak, in actual practice. This amounts to a difference of (51.7-44)/1.9, or more than 4 standard deviations. Thus, it is exceptionally unlikely that the preference for off-peak scheduling actually observed happened by random chance. When done correctly, the statistical analysis used by PacifiCorp does not support the Company's conclusion that it should be allowed to ignore the time differentiation of deferrable outages.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE PACIFICORP ANALYSIS?

A. Most definitely. First, the statistic computed appears to exclude derations, which allow more scheduling flexibility than complete outages. This tends to overstate the amount of deferrable maintenance that would occur on-peak. Second, while PacifiCorp used an average over the period 2002-2008, not all of the resources were on line the entire period. Chehalis, for example, was only on line a few months, and has only a few hours of deferrable outages reported. Yet, PacifiCorp reported 3 identical observations for Chehalis (Che-1, Che-2 and Che-3). In effect, PacifiCorp gave a few months of data for Chehalis (which buttresses their conclusion) three times the weight of seven years of data for the PacifiCorp coal-fired units. Finally, even the standard deviations and other statistics reported by PacifiCorp are highly suspect. The underlying distributions are clearly not normally distributed because they must fall within a range of zero and one. As a result, ordinary statistical inferences, such as those suggested by PacifiCorp, cannot be assumed to be valid. Then again, PacifiCorp acknowledged its data was "statistically suspect." ICNU/201.

Q. DO YOU AGREE WITH THE PACIFICORP OUTAGE RATE FORMULAE FOR MODELING PURPOSES?

A. No. Mr. Godfrey's formula is incorrect for power cost modeling applications since he fails to deduct planned outage hours from the denominator. I raised this issue during the various discussions held in this proceeding, but PacifiCorp seemed quite unwilling to discuss the matter.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THE PROBLEMS IN THE PACIFICORP FORMULA?

A. Yes. Exhibit ICNU/202 shows a hypothetical example that illustrates the problem with Mr. Godfrey's formula if it were applied in the GRID model. In the example, the resource is assumed to be a 100 MW unit that is on forced outage one day during the month and on planned outage seven days. (I use a monthly analysis rather than annual for simplicity only. Nothing in the exhibit would change were I to model an entire year, though it would require many more pages to present.) Using Mr. Godfrey's formula, the outage rate would be 1/31, or 3.2%. The correct outage rate for use in the GRID model would be 1/(31-7), or 4.2%. If the capacity in the model is derated using Mr. Godfrey's incorrect formula, energy produced by the unit would be overstated, as is shown in the exhibit.

Q. WOULD MAKING THIS CORRECTION TEND TO INCREASE POWER COSTS?

A. Yes. Ordinarily, one would not expect a utility company to make such a mistake, particularly when it goes against their own best interests. Because I assume that eventually the mistake will be corrected, I believe its better to simply address it now than to encounter it at a later date, when it would most certainly be an issue.

Q. ON PAGE 7 OF YOUR DIRECT TESTIMONY YOU INDICATE THAT YOU WOULD RESPOND TO THE UTILITIES' PROPOSALS CONCERNING $EFOR_d$, WHICH IS USED TO MODEL OUTAGES OF PEAKING PLANTS. HAVE THE UTILITIES ADDRESSED THIS ISSUE?

A. No. Mr. Godfrey proposes a different formula for an outage rate to be applied in GRID for gas units, EUOR. However, this formula appears to rely on data that is not now being collected by the Company, Equivalent Forced Derated Hours During Reserve Shutdowns and Equivalent Maintenance Derated Hours During Reserve Shutdowns. I have requested substantial outage related data from the Company over the years, and never seen these items reported. I believe that it would be rather subjective for a utility to determine how many hours a resource might have been derated during a reserve shutdown. As a result, I do not believe Mr. Godfrey's formula is useful, or fair, since the Company will likely leave out a component that would tend to reduce outage rates. All things considered, I believe the $EFOR_d$ provides a better, industry standard solution.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING PACIFICORP'S TESTIMONY?

A. Yes. The Company did not address some of the issues on the issues list, such as whether adjustments should be allowed to outage rates. In my direct testimony, I discussed the issue of ramping. It seems to me that the Company had an opportunity to justify its ramping adjustment in its direct testimony, but did not do so. As a result, I believe the Commission should discount any arguments or data the Company may present in its reply testimony concerning these issues, as the parties will not have had an opportunity to address this evidence or arguments that should have been made in their direct case. The Company's failure to address issues on the issues list and lack of completeness should not used against opposing parties.

Q. DO YOU HAVE ANY COMMENTS ON CUB'S TESTIMONY?

A. Yes. The Citizen's Utility Board ("CUB") supports the PacifiCorp (GRID) methodology for modeling of outages rates within a power cost model, as opposed to the PGE (MONET) methodology:

> The generally-accepted forecasting model is one that utilizes a four-year rolling average to determine the appropriate expected outage period. Because by definition we cannot predict when a forced outage will occur, we then model the outage by "derating" the plant – that is, by reducing the capacity factor of the plant.

CUB/100, Jenks/5.

If accepted, CUB's proposal would result in an increase in net power costs for PGE in the current Annual Power Cost Update Tariff ("AUT") proceeding over and above the PGE request.

I have designed power cost models used by many utility companies, and reviewed power cost models in numerous states, and I strongly disagree with CUB's characterization of the PacifiCorp method as "generally-accepted." The very fact that PGE applies the approach differently in MONET belies CUB's claim on this point.

Q. CAN YOU PROVIDE A SIMPLE EXPLANATION OF THE DIFFERENCES IN THE PGE AND PACIFICORP METHODOLOGIES?

A. Yes. PGE does two things differently from PacifiCorp. First, PGE applies the deration factor to the minimum unit capacity, rather than just the maximum loading which CUB considers to be the "generally accepted." This is necessary, or the amount of energy being produced by a unit when running at minimum will be overstated. In mathematical terms, the minimum loading deration is necessary so that the expected value of generation under minimum loading conditions will be computed correctly. PGE assumes that when a unit is on outage, it cannot run at either the minimum or maximum capacity. PacifiCorp assumes that when a plant is on outage, it cannot run at its maximum capacity, but it could run at its minimum capacity. The PacifiCorp method, which CUB endorses, is absurd. In contrast, the PGE method applies common sense.

Second, in MONET, PGE makes sure that no matter what, forced outage rate is inputted into the model, so that the heat rate for the unit is not impacted. Under the PacifiCorp method, when the outage rate for a plant is increased, its heat rate will also automatically increase. This was demonstrated in my direct testimony. This is again, an absurd outcome, because it doesn't impact the unit's heat rate if the unit was on a one or two week forced outage. Under the PacifiCorp method, forced outages decrease the capacity of the unit, and move it down to a less efficient spot on the heat rate curve. While partial outages do result in some minor heat rate degradation (which is reflected in my proposed methodology) full forced outages do not materially impact generator heat rates.[3/] Again, if the CUB/PacifiCorp method is adopted, then PGE would be awarded an unjustified, and unrequested, increase in power costs in the AUT case, and PacifiCorp would be allowed to collect overstated power costs.

Q. DO YOU MODEL THE HEAT RATE ADJUSTMENT IN EXACTLY THE SAME MANNER AS PGE DOES IN MONET?

A. The effect is identical, but GRID uses a heat rate curve methodology, while PGE uses a fixed heat rate input by loading segment or operating configuration. Thus, I use the GRID equation adjustment (which PacifiCorp is already using for fractionally owned units such as Colstrip) rather than a fixed heat rate curve input. In MONET, if the heat rate of a unit at maximum capacity is 10,000 BTU/KWH, that heat rate stays the same, whether the capacity of the unit is derated by a 5%, 10% or even higher outage rate. Under the PacifiCorp/CUB proposal, the full load heat rate is higher with a 10% outage rate rather than a 5% outage rate.

3/ The number of starts a unit encounters due to outages arguably would impact the heat rate. However, the PacifiCorp methodology for modeling heat rates adjusts the design heat rate to match actual operation, thus it already reflects starts and stops.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING PGE'S TESTIMONY?

A. I'm surprised that PGE seems to object to applying the same modeling methods to both PGE and PacifiCorp. For one thing, PGE is already doing many things "right" (i.e., hydro optimization, ignoring hydro outage rates, building ramping into its hourly dispatch modeling, and modeling heat rates and minimum loading segments correctly) compared to the things that PacifiCorp is doing incorrectly. PGE disagrees with the "one-size fits all" premise underlying computation of outage rates in this case. However, the companies should use the same methodologies in computing outage rates. It does not make sense that PGE and PacifiCorp would use the same historical data, but use different methods and formulae to compute different outage rates for the same resource (both own a share of Colstrip). Proper modeling methods and reasonable techniques are not company specific. Much like gravity, mathematics and common sense should apply equally to everyone. The purpose of this docket was to establish guidelines and procedures applicable to all companies, and to avoid the many needless controversies that have plagued recent cases. Adopting proposals to simply perpetuate the status quo in this case would amount to wasting the time of the parties who made an honest effort to address the pertinent issues. Putting in place consistent, clearly identified methodologies for both utilities will simplify this issue and hopefully lead to more settlements of this issue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

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	)
The Public Utility Commission of Oregon	)
Investigation into Forecasting Outage Rates	)
For Electric Generating Units	)
	)

ICNU 201

May 13, 2009

20000-341-EP-09/Rocky Mountain Power
April 16, 2009
WIEC 4th Set Data Request 4.8

WIEC Data Request 4.8

PacifiCorp's response to WIEC Data Request 1.20 is not responsive. WIEC requested that PacifiCorp provide **justification** for using forced outages rates that are not differentiated between peak and off-peak periods, when PacifiCorp has the ability to defer the timing of some forced outages. PacifiCorp unresponsively stated that it does not differentiate between peak and off-peak periods. Provide the justification originally requested.

Response to WIEC Data Request 4.8

Please refer to Attachment WIEC 4.8. To respond to this data request, the Company analyzed outage data for forced outages and maintenance outages over a seven-year period, from January 1, 2002, through December 31, 2008. The Company looked at forced outages during on-peak and off-peak hours and maintenance outages between on-peak and off peak hours.

For forced outages it was determined that historically 58% of the hours off-line were during on-peak hours, and 42% of the hours off-line were during off-peak hours. These data had one standard deviation of 5.34%, which means the data is fairly well grouped around the averages and is statistically significant. It needs to be pointed out that the Company does not have the ability to defer or schedule forced outages based on their very nature. Furthermore, historical performance is not a good predictor for this category of events.

The maintenance outages had historical averages of 48% of the hours off line during on-peak hours and 52% of the hours off line during off-peak hours. These data had one standard deviation of 13.34% (over twice the variability of the forced outage data), which means the data is not well grouped around the averages and is statistically suspect.

Given the above analysis and results, the Company does not differentiate between on-peak and off-peak periods.

Docket No. 20000-341-ER-09 / Wyoming PCAM 2009
WIEC Data Request 4.8

Period	Unit ID	On Peak Forced Outage Hrs.	Off Peak Forced Outage Hrs.	On Peak Maint. Outage Hrs.	Off Peak Maint. Outage Hrs.		On Peak Forced Outage (%)	Off Peak Forced Outage (%)	On Peak Maint. Outage (%)	Off Peak Maint. Outage (%)	On Peak Forced Outage (%)	Off Peak Forced Outage (%)	On Peak Maint. Outage (%)	Off Peak Maint. Outage (%)
2002-2008	BLN-1	629	403	341	172		61.0%	39.0%	66.5%	33.5%	>0	>0	>0	>0
2002-2008	BLN-2	1,028	736	215	149		58.3%	41.7%	59.0%	41.0%				
2002-2008	CHE-1	22	11	23	14		66.7%	33.3%	62.2%	37.8%				
2002-2008	CHE-2	67	38	23	14		64.2%	35.8%	62.2%	37.8%				
2002-2008	CHE-3	1	0	23	14		82.3%	17.7%	62.2%	37.8%				
2002-2008	CHO-4	1,789	1,548	-	-		53.6%	46.4%	0.0%	0.0%				
2002-2008	COL-3	2,974	2,365	223	220		55.7%	44.3%	50.3%	49.7%				
2002-2008	COL-4	1,102	806	440	479		57.8%	42.2%	47.9%	52.1%				
2002-2008	CRB-1	1,868	1,528	154	177		55.0%	45.0%	46.5%	53.5%				
2002-2008	CRB-2	936	926	455	403		50.3%	49.7%	53.0%	47.0%				
2002-2008	CRG-1	1,293	1,089	-	-		54.3%	45.7%	0.0%	0.0%				
2002-2008	CRG-2	881	712	33	63		55.3%	44.7%	34.0%	66.0%				
2002-2008	CUR-1	511	323	118	132		61.3%	38.7%	47.2%	52.8%				
2002-2008	CUR-2	485	321	174	177		60.2%	39.8%	49.7%	50.3%				
2002-2008	CUR-3	506	343	66	79		59.6%	40.4%	45.8%	54.2%				
2002-2008	DJ-1	719	596	32	27		54.7%	45.3%	54.0%	46.0%				
2002-2008	DJ-2	336	283	80	73		54.2%	45.8%	52.4%	47.6%				
2002-2008	DJ-3	1,375	1,191	403	290		53.6%	46.4%	58.2%	41.8%				
2002-2008	DJ-4	1,974	1,693	511	438		53.8%	46.2%	53.8%	46.2%				
2002-2008	GAD-1	326	224	-	-		59.3%	40.7%	0.0%	0.0%				
2002-2008	GAD-2	541	401	10	18		57.4%	42.6%	35.7%	64.3%				
2002-2008	GAD-3	411	251	173	172		62.1%	37.9%	50.1%	49.9%				
2002-2008	GAD-4	496	285	136	133		63.5%	36.5%	50.7%	49.3%				
2002-2008	GAD-5	949	664	48	64		58.8%	41.2%	42.8%	57.2%				
2002-2008	GAD-6	811	560	-	-		59.2%	40.8%	0.0%	0.0%				
2002-2008	HDN-1	917	838	410	369		52.3%	47.7%	52.6%	47.4%				
2002-2008	HDN-2	679	549	372	346		55.3%	44.7%	51.8%	48.2%				
2002-2008	HRM-1	261	297	160	195		46.8%	53.2%	45.1%	54.9%				
2002-2008	HRM-2	962	796	137	160		54.7%	45.3%	46.1%	53.9%				
2002-2008	HTG-1	2,266	1,930	255	234		54.0%	46.0%	52.1%	47.9%				
2002-2008	HTG-2	2,215	1,575	55	47		58.4%	41.6%	53.9%	46.1%				
2002-2008	HTR-1	1,874	1,326	407	397		58.6%	41.4%	50.6%	49.4%				
2002-2008	HTR-2	1,382	1,043	557	479		57.0%	43.0%	53.8%	46.2%				
2002-2008	HTR-3	1,585	1,204	469	495		56.8%	43.2%	48.6%	51.4%				
2002-2008	JB-1	1,859	1,346	485	383		58.0%	42.0%	55.8%	44.2%				
2002-2008	JB-2	2,275	1,759	246	258		56.4%	43.6%	48.8%	51.2%				
2002-2008	JB-3	1,879	1,404	270	303		57.2%	42.8%	47.1%	52.9%				
2002-2008	JB-4	1,862	1,427	329	243		56.6%	43.4%	57.5%	42.5%				
2002-2008	LMT-1	682	503	79	32		57.5%	42.5%	71.2%	28.8%				
2002-2008	LS-1	137	80	-	-		63.3%	36.7%	0.0%	0.0%				
2002-2008	LS-2	160	96	32	48		62.7%	37.3%	40.2%	59.8%				
2002-2008	LS-3	160	97	-	-		62.2%	37.8%	0.0%	0.0%				
2002-2008	NTN-1	780	703	389	389		52.6%	47.4%	50.0%	50.0%				
2002-2008	NTN-2	644	557	511	562		53.6%	46.4%	47.6%	52.4%				
2002-2008	NTN-3	1,428	1,040	863	860		57.9%	42.1%	50.1%	49.9%				
2002-2008	WV-1	487	364	-	7		57.3%	42.7%	0.0%	100.0%				
2002-2008	WV-2	494	297	1	27		62.4%	37.6%	4.9%	95.1%				
2002-2008	WV-3	245	180	1	7		57.7%	42.3%	6.5%	93.5%				
2002-2008	WV-4	1,279	950	3	7		57.4%	42.6%	30.2%	69.8%				
2002-2008	WV-5	309	196	1	7		61.2%	38.8%	16.3%	83.7%				
2002-2008	WYO-1	725	492	758	486		59.6%	40.4%	60.9%	39.1%				
						Avera	58.0%	42.0%	48.3%	51.7%				
						1 STD	5.3%	5.3%	13.3%	13.3%				

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

In the Matter of	)
	)
The Public Utility Commission of Oregon	)
Investigation into Forecasting Outage Rates	)
For Electric Generating Units	)
	)

ICNU 202

May 13, 2009

Illustration of Proper Calculation of Outage Rate for Power Cost Models

		Capacity	100	
PacifiCorp	Forced	Outage Rate	=1/31	3.23%
	Planned	Outages	=7/31	
Correct	Forced	Outage Rate	=1/(31-7)	4.17%

	Actual			PacifiCorp Formula		Correct Formula	
	Capacity	Energy		Capacity	Energy	Capacity	Energy
1	100	2400	Fully Operating	96.77	2322.6	95.83	2300
2	0	0	Forced Outage	96.77	2322.6	95.83	2300
3	100	2400	Fully Operating	96.77	2322.6	95.83	2300
4	100	2400	"" ""	96.77	2322.6	95.83	2300
5	100	2400	"" ""	96.77	2322.6	95.83	2300
6	100	2400	"" ""	96.77	2322.6	95.83	2300
7	100	2400	"" ""	96.77	2322.6	95.83	2300
8	100	2400	"" ""	96.77	2322.6	95.83	2300
9	100	2400	"" ""	96.77	2322.6	95.83	2300
10	100	2400	"" ""	96.77	2322.6	95.83	2300
11	100	2400	"" ""	96.77	2322.6	95.83	2300
12	100	2400	"" ""	96.77	2322.6	95.83	2300
13	100	2400	"" ""	96.77	2322.6	95.83	2300
14	0	0	Planned Outage	0	0.0	0.00	0
15	0	0	"" ""	0	0.0	0.00	0
16	0	0	"" ""	0	0.0	0.00	0
17	0	0	"" ""	0	0.0	0.00	0
18	0	0	"" ""	0	0.0	0.00	0
19	0	0	"" ""	0	0.0	0.00	0
20	0	0	"" ""	0	0.0	0.00	0
21	100	2400	Fully Operating	96.77	2322.6	95.83	2300
22	100	2400	"" ""	96.77	2322.6	95.83	2300
23	100	2400	"" ""	96.77	2322.6	95.83	2300
24	100	2400	"" ""	96.77	2322.6	95.83	2300
25	100	2400	"" ""	96.77	2322.6	95.83	2300
26	100	2400	"" ""	96.77	2322.6	95.83	2300
27	100	2400	"" ""	96.77	2322.6	95.83	2300
28	100	2400	"" ""	96.77	2322.6	95.83	2300
29	100	2400	"" ""	96.77	2322.6	95.83	2300
30	100	2400	"" ""	96.77	2322.6	95.83	2300
31	100	2400	"" ""	96.77	2322.6	95.83	2300
Total Energy		55200			55741.9		55200.0