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	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

SUBJECT TO GENERAL PROTECTIVE ORDER

April 7, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101. I have participated in and filed testimony in numerous cases involving PacifiCorp and Portland General Electric ("PGE") net power cost issues over the past ten years.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony will address the issues contained on the final issues list approved by the ALJ in this proceeding. These issues are attached as Exhibit ICNU/102. This testimony will address the questions on the issues list roughly in the order they appear on Exhibit ICNU/102, with a few exceptions.

Q. PLEASE SUMMARIZE THE MAJOR POINTS OF YOUR TESTIMONY.

A. The major points of my testimony are as follows:

1. **I present statistical data supporting the use of a weekend/weekday or HLH/LLH split for modeling of forced outage rates. This approach conforms to actual practice in utility operations.**

2. **Planned outages should also be scheduled based on historical scheduling patterns, following the actual cost minimizing practices of**

the utilities. I present a methodology for determination of planned outage schedules for power cost studies based on the actual schedules used by utilities. This is superior to PacifiCorp's arbitrary and unstable "normalization" approach, and avoids many of the past problems experienced with PGE's use of forecasted schedules.

3. **The Commission should continue to make prudence disallowances for unplanned outages caused by management failures, and continue to make adjustments to remove costs of extremely long outages.**

4. **PacifiCorp's forced outage modeling of hydro resources should be rejected as it is arbitrary, poorly documented and unrealistic. PGE does not now model hydro forced outages in MONET.**

5. **PacifiCorp should adopt PGE's capacity deration and heat rate modeling method from MONET to correctly apply outage rates in GRID. PacifiCorp's method is simply wrong and can produce absurd results.**

6. **Outage rates for gas-fired plants should be based on the North American Electric Reliability Council ("NERC") Equivalent Forced Outage Rate demand ("$EFOR_d$") methodology. $EFOR_d$ is widely accepted within the industry for modeling outage rates of peaking and cycling units.**

7. **Ad-hoc adjustments, such as PacifiCorp's ramping adjustment should not be allowed in modeling of outage rates. Outage rates should be based on industry standard data and formulae.**

8. **For new resources, the same outage rates as used in the integrated resource planning ("IRP") or resource evaluation process should be applied until there is sufficient data to compute a realistic outage rate from resource specific data.**

9. **A multi-year average should be used to compute outage rates. Absent compelling statistical support for making a change, the four year average should continue to be used. I recommend certain reporting requirements and an incentive mechanism to avoid the unintended consequences stemming from use of historical outage data.**

Q. WHAT FORECASTING METHODOLOGY SHOULD THE COMMISSION ADOPT FOR THERMAL GENERATING PLANTS?

A. In general, outage rates should be based on a resource specific multi-year rolling average when valid historical data are available. The length of the rolling average period should be determined by a sound statistical methodology, if possible, and should reflect traditional ratemaking concepts such as normalization. As a default, in the absence of any compelling statistical data, ICNU recommends continued use of the four year average. However, ICNU will certainly consider whatever evidence Staff and the parties present regarding this matter.

Q. ARE THERE ANY EXECPTIONS TO THIS RECOMMENDATION?

A. Yes. A problem with any method that relies solely on historical data is that it tends to provide for eventual recovery of replacement energy for all outages that occur. Because market prices have tended to increase over time, this can have the unintended consequence of rewarding poor performance. The Commission can address this problem by requiring utilities to file data tracking their plant availability statistics and making comparisons to NERC averages for comparable plants. In cases where performance declines, or falls short of industry averages, the Commission should consider alternatives to the use of historical data. These will be discussed later. Further, the Commission should remove imprudent and unusual outages that occurred during the historical period from computation of the outage rates.

Q. SHOULD THERE BE A DIFFERENT METHOD FOR COMPUTATION OF OUTAGE RATES FOR PEAKING OR CYCLING GENERATORS AS COMPARED TO BASELOAD PLANTS?

A. Yes. In recent PacifiCorp and PGE power cost cases, it has become apparent that outage rates for certain peaking or cycling units are overstated when compared to actual, prudent operations. For PGE, the Beaver plant has a very high unplanned outage rate. In fact, for one of the units, [redacted], the outage rate approached [redacted]. For PacifiCorp, the Gadsby peaking units also have been modeled using high outage rates. In some cases this has been true for the combined cycle plants, as well, when monthly outage rates were used. There are two problems that cause these results. First, there is the problem of computing lost energy for units that are frequently shut down or cycled. Second, there is the problem of deferrable maintenance.

For units that cycle frequently, the method used by PGE and PacifiCorp tends to overstate the amount of time or energy lost due to outages. When computing lost production, it is normally assumed that when cycling units are down for outages, they would have otherwise been running for the entire period. Thus, the assumed amount of energy lost, would be the maximum possible generation *if* these units were running fully loaded during the period they were on outage. This is a reasonable assumption for baseload plants because they normally run as much as possible, but does not reflect how cycling or peaking units are operated.

Q. PLEASE PROVIDE A SIMPLIFIED EQUATION SHOWING HOW OUTAGE RATES ARE COMPUTED.

A. In their simplest form, outage rates are computed as the ratio of lost energy divided by potentially available energy production:[1/]

Outage Rate = (Energy Lost Due to Outages)/(Total Possible Generation – Planned Outage Energy – Reserve Shutdown Outage Energy)

This is significant because reserve shutdowns impact both the numerator, and the denominator in the equation above.

1/ PGE generally used time rather than energy in the computation of outage rates. Thus, it converts lost energy to the hours of lost production, and available energy to available hours. All these quantities are proportional, assuming a constant nameplate capacity.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS PROBLEM?

A. Yes. Based on publicly filed data, starting April 30, 2006, Currant Creek experienced a long (680 hour) outage due to a problem with the generator output breaker. PacifiCorp's lost energy calculations for the event were based on the assumption that, in the absence of the outage, the plant would have been running the entire 680 hour period fully loaded. This is a rather unlikely outcome because during the months of April (before the outage) and June 2006 (after the outage) the plant was normally shut down at night. Review of non-confidential data contained in response to ICNU data request ("DR") 1.6-2 provided in UE 199, shows that during April and June 2006, the plant was placed on reserve shutdown nearly half the time. As a result, the assumption that Currant Creek would have been running fully loaded during the outage period is unsupportable and overstates the outage rate for Currant Creek. In its April 2008 filing in UE 199 (and its July filing in Utah) PacifiCorp assumed that Currant Creek would have an outage rate of 50% in May 2009 using this approach.[2/]

This issue illustrates a systematic problem with the PacifiCorp methodology for computing outage rates for cycling units. PacifiCorp overstates lost energy because reserve shutdowns are not considered in numerator of the outage rate equation the when lost energy is computed.

Q. IS THAT THE ONLY PROBLEM WITH THIS APPROACH?

A. No. The reserve shutdowns are also removed from the denominator. This means that if a unit is shutdown every night, it reduces the amount of potential generation. This magnifies the effect of the energy lost during outages because it assumes that

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[2/] This was based on monthly modeling of outages, which the Company later abandoned.

the outages would have resulted in lost energy during the nights, which is the time when the units would likely have been shutdown. In mathematical terms this is known as a "double whammy." For units that seldom run, this can become a substantial problem.

Q. DISCUSS THE PROBLEMS RELATED TO DEFERRABLE MAINTENANCE OF CYCLING AND PEAKING PLANTS.

A. This is a similar problem. It has been recognized for quite some time that there is a problem in computing outage rates for units with very low capacity factors, because the inclusion of maintenance outages as part of the overall unplanned outage rate overstates the chance of an outage when the plant actually needs to operate. The reason is maintenance outages can be deferred until times when the resource is not needed at all. Consequently, it is quite likely that the energy considered lost during a deferrable outage was actually deferred to a period when reserve shutdowns would have occurred.

Q. IS THERE A SOLUTION TO THIS PROBLEM?

A. Yes. Utilities have developed an alternative outage rate calculation, known as "$EFOR_d$" which is the Equivalent Forced Outage Rate demand. This is the outage rate during the plants "demand period" – the time a resource is most likely to run. $EFOR_d$ is defined and reported by NERC, and it is widely used in the industry. The basic premise of the $EFOR_d$ is to discount maintenance outages since they don't need to occur when a low capacity factor resource is required. Exhibit ICNU/103 is a copy of pages from a NERC document defining and explaining $EFOR_d$.

Q. SHOULD THE $EFOR_d$ BE APPLIED IN GRID AND MONET?

A. Using the EFORd would provide a reasonable solution to the problem of modeling outage rates for generators that frequently do are on reserve shutdown. Exhibit ICNU/104 shows that for units that are seldom on reserve shutdown (i.e., baseload plants that run all the time), there is little difference between the EFOR and EFORd. However, for units, such as gas-fired generators that are frequently on reserve shutdown, the EFORd is substantially different from the EFOR. Thus, if the EFORd is used, I believe it would only need to be applied to gas-fired units.

There are practical problems related to the use of $EFOR_d$. In a recent PGE case, the matter of $EFOR_d$ was raised in discovery. Unfortunately, PGE indicated it did not have the data readily available to make this computation. As a result, I recommend that the Commission direct PGE and PacifiCorp to begin developing such data, and in the meantime, allow parties to develop approximations. Alternatively, there may be other means for addressing these issues which could be explored in future cases. Perhaps the utilities will make proposals to deal with this issue in their direct testimony. If so, I will address that in my rebuttal testimony. The simplest approach would be to remove reserve shutdowns from the denominator of the outage rate computation, and make adjustments to the data used in the numerator to remove its adverse impacts.

Q. ARE THERE SPECIAL CONSIDERATIONS FOR MODELING OUTAGE RATES OF COMBINED CYCLE PLANTS?

A. Yes. Combined cycle plants have multiple modes of operation, and may have multiple units at each plant. Further, these plants may have duct firing capability, and in some circumstances may be able to operate in either combined cycle or simple cycle mode. If one component of a plant is not available, (e.g., a single combustion turbine) the output of the plant as a whole is diminished. Likewise, if the heat recovery steam generator ("HRSG") is out of service, the maximum capacity for the plant cannot be achieved.

This results in a wide variety of possible configurations for each plant. To properly assess the outage rates for combined cycle units, ICNU proposes an "expected value" approach be employed. This is illustrated in Exhibit ICNU/105 for the Currant Creek plant. This approach computes the expected value of capacity available from a combined cycle plant based on the outage rates for individual combustion turbines and the HRSG. While there may be ways to improve this approach, it is a reasonable approximation for power cost modeling purposes.

Q. WHAT FORCED OUTAGES SHOULD BE CONSIDERED IN OUTAGE RATE COMPUTATIONS?

A. In UE 191, the OPUC made specific adjustments to remove imprudent outages from computation of outage rates, as well as an adjustment to remove an extraordinarily long outage. ICNU recommends the Commission continue this practice, and formalize standards for exclusion of imprudent or extraordinary outages in this proceeding. In Order 07-446, the Commission stated:

> For ratemaking purposes, we do not assume that Pacific Power will be imprudent during the test year. Imprudently incurred costs are not recoverable in rates. Imprudently caused plant outages must be removed from the calculation of the outage rate for TAM purposes.
>
> We do make a distinction between outages caused by management failure (imprudence) and operator error (mistake). We recognize that mistakes are part of the real time operation of a complicated facility in a complicated system. If the rate of operator error were to appear excessive, we might also characterize that result as a

> management failure. Because of Pacific Power's overall performance, there are no grounds to infer that management failure has contributed to operator error.
>
> Management failure occurs "upstairs," away from the control room, with time for deliberation and consideration of all factors. Management failure constitutes imprudence. Pacific Power's RCA reports are highly probative evidence of the consequences of Pacific Power's management decisions.

Re PacifiCorp, OPUC Docket No. UE 191, Order 07-446 at 20 (October 17, 2007).

ICNU believes this is a reasonable standard, and recommends it be adopted as the guiding principle for determination of prudence related disallowances. Consequently, outages that result from management failures should be disallowed as imprudent. In addition, while certain mistakes are part of regular operations, the Commission should recognize that certain operator mistakes caused by negligence or willful misconduct are not recoverable from ratepayers.

Further, in the same order, the Commission stated as follows:

> The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model.

Id. at 21.

Again, this is a reasonable standard to employ. Outages longer than 28 days should be removed from the computation of average outage rates used in power cost models. This is a fair standard because one would not expect extraordinarily long outages to occur frequently. As a general matter, the Oregon

Public Utility Commission ("OPUC" or the "Commission") has already recognized that ratepayers should not be assumed to automatically be responsible for all of the costs of long outages or other extreme events. This adjustment is in keeping with that premise.

For extreme events, the Commission has allowed utilities to use deferrals to capture some, but not all outage related costs. ICNU recommends this principle be reaffirmed by the Commission. Review of PacifiCorp event data shows that only about 1 in 600 outage events lasts longer 28 days, and very few such events occur in any four year period. Identification of such outages is not difficult, and removing the impact of extremely long outages from power cost models will provide utilities with incentives to achieve good performance.

Q. PLEASE DISCUSS THE COMMISSION'S APPROACH REGARDING DEFERRALS AND ITS RELATIONSHIP TO THIS ISSUE.

A. In various orders concerning deferrals, the OPUC discussed the concepts of "Stochastic Risks" and "Scenario Risks." Stochastic risks are not appropriate for deferral as they are built into ordinary rate. Scenario risks are eligible for deferral, but the Commission has required utilities to demonstrate those events have had a significant financial impact. An a-priori removal of long outages would be consistent with the Commission's views in that it does not assume, as a matter of course, that ratepayers are at risk for all consequences of unusual or extreme events. My analysis shows that for PacifiCorp, 0.167% of outages lasted longer than 28 days.

Q. DOES THE FACT THAT SUCH LONG OUTAGES ARE RARE MEAN THAT THEY ARE NOT IMPORTANT?

A. No. These extremely long outages have a disproportionate impact on total lost energy. In the case of PacifiCorp, such outages are responsible for about 4.6% of all energy lost due to forced outages, even though they represent only one in 600 events.

Q. SHOULD INDUSTRY DATA BE CONSIDERED IN THIS ANALYSIS?

A. In this case, industry data may not be particularly useful. First, data concerning outage durations may not be publicly available. Consequently, its use would pose problems in regulatory proceedings in terms of access to all parties. Second, by its very nature, these are "extreme" events. Such events don't lend themselves to ordinary statistical analysis, and it would be rather difficult to establish an "industry standard" for the frequency of extreme events.[3/]

Q. WHAT METHODOLOGY SHOULD BE EMPLOYED FOR TREATMENT OF EXCLUDED OUTAGES?

A. In cases where an outage should be excluded, the most reasonable approach would be to assume the resource would have been available and running in its normal pattern absent the event. The alternative proposed in some cases has been to exclude the entire outage period from the calculation of the outage rate for a particular resource. The problem with this approach is that it entails the use of an artificially shortened historical period. For example, if a six month outage were

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3/ In "The Black Swan" by Nassim Taleb, these concepts are discussed at length. Stochastic risks, reside in the realm of "Medicristan" and are predictable, ordinary, and a have a measurable impact on the cost of doing business. Scenario risks reside in the realm of Extremistan, being unpredictable, with potentially large impacts. In "The Black Swan," Taleb discusses the futility of making statistical inferences for extreme events, and argues instead for a system that is robust in the face of such events. Based oh his concepts, long outages should not be reflected in conventional normalized ratemaking, but could be eligible for some recovery in a deferral mechanism. This is well in keeping with the OPUC's treatment of long outages.

excluded (on the basis of prudence, or because it was an extreme event) and the OPUC adopted a 48 month rolling average, as in the past, the resulting outage rates would be computed based on only 42 months of data. This approach basically "forgives" some of the impact of the excluded outage based on the assumption that the resource would have been offline some of the time, absent the event. This provides a perverse incentive for poor performance overall. Further, for very long outages, it diminishes the statistical viability of the data.

Q. HOW SHOULD OUTAGE RATES FOR NEW RESOURCES BE COMPUTED?

A. For new resources, outage rates used in the IRP process and competitive bid evaluations should be used without any adjustments until sufficient historical data is available to supplant the need for such data. The outage rates for new wind resources should be based on wind potential studies used by the Company in project evaluations until there is a sufficient amount of data available to produce accurate site specific forecasts. For all types of resource, historical data for the first few years of operation should be excluded from the computation of outage rates because poor performance during initial operation is common. After this initial phase of operation, outage rates typically improve and reach a steady-state equilibrium. These values should be used in power cost studies. Thus, ICNU recommends exclusion of outage rate data for the first year or two of operation of a new resource from any eventual average outage rate calculation.

Q. WOULD THIS BE AN UNFAIR PENALTY FOR UTILITIES? FOR EXAMPLE, IF IT WAS ASSUMED A RESOURCE HAD A LOW LIFETIME OUTAGE RATE BASED ON INDUSTRY STANDARD DATA, WOULDN'T THE UTILITY BE DENIED THE OPPORTUNITY TO RECOVER COSTS RESULTING FROM OUTAGES DURING THE INITIAL PERIOD OF OPERATION?

A. Not at all. The companies could easily factor in poor initial operation into their resource selection process. They could use both immature and mature forced outage rates in evaluations made in the resource selection process. They should be doing so already, in order to make the best resource selection decisions.

ICNU's proposal should encourage utilities to perform realistic IRP studies and request for proposal ("RFP") evaluations that reflect appropriate outage rates that will be used to compare purchase and build resource acquisition options. It is true that generator outage rates are often higher during initial operation than in later years; however, these high initial outage rates are often ignored in the resource selection processes. This provides a bias for self build options and new construction as opposed to purchased power contracts, or purchases of assets already in operation.

Q. WHAT IS THE APPROPRIATE LENGTH FOR THE HISTORICAL PERIOD?

A. The OPUC has used a 48 month (four year) rolling average outage rate since the 1980s. ICNU and Staff, have proposed alternatives either longer time periods (in the case of ICNU) or use of industry average data (both Staff and ICNU).

The resolution of this issue is probably not one that can be decided on the basis of an analysis of historical data. While ICNU does not oppose use of a different time period, per se, we believe that much shorter periods will prove to be too unstable for power cost studies. Much longer periods may be too insensitive to recent availability trends.

Ultimately, the problem is not so much what historical period is chosen, but rather, whether use of historical averages (of any particular length) creates perverse incentives. If utilities have an expectation that the cost of an outage today will be factored into future rates, and eventually recovered, then there is not a strong incentive is minimize the occurrence of outages. Indeed, there is the likelihood that longer and more costly outages will be tolerated.

In this regard, the treatment of fixed and variable costs in normalized ratemaking is fundamentally at odds. While the use of a historical rolling average results in eventual recovery of replacement power costs (indexed to the market) the recovery of costs between rate cases for capital improvements and repairs is not. As a result, the incentive for utilities is to skimp on maintenance and improvement costs and let outage increase. Trends over the past decade show this has happened with both PGE and PacifiCorp. Indeed, this problem was part of the impetus for this docket in the first place.

Q. HOW CAN THESE PERVERSE INCENTIVES BE ADDRESSED?

A. If the utility has some doubt as to whether outage costs will be recovered in rates, then there is an incentive to minimize outages. Use of the techniques and standards discussed above (prudence disallowances, or removal of long outages) provides some incentives for improved management because it reduces validity of the assumption of ultimate recovery of all outage costs.

Q. IS THERE A WAY IN WHICH THE COMMISSION COULD BUILD INCENTIVES INTO THE PROCESS BUT BUILD UPON THE ROLLING AVERAGE FRAMEWORK THAT HAS BEEN USED FOR MANY YEARS?

A. Yes. One approach would be to allow use of historical outage rate data (for sake of argument, the four year rolling average) amended by trends in plant availabilities. If the utility can demonstrate that its four year rolling average availability rate has improved since the last filing, the company would be allowed to retain a share of the benefit of its improved performance. If, however, the four year rolling average shows a decline in performance, then a share of the decline in performance would be absorbed by the Company. This process should only be used for mature plants, and should be differentiated by fuel type (e.g., coal, gas, hydro, etc.). In this manner a large improvement in availability rates for gas plants (that has a small impact on power costs) could not be used to offset decreases in availability of coal plants.

Q. WOULD INDUSTRY DATA PLAY A ROLE IN THIS?

A. Industry data may be useful to establish if there are underlying trends. For example, NERC data tends to show improvements in outage rates for many types of generators over time. This might be factored into the process at some point. If however, fleet aging was shown to be resulting in declining plant availabilities in the future, then that might be taken into consideration.

Q. SHOULD UTILITY INCENTIVE COMPENSATION BE CONSIDERED BY THE COMMISSION?

A. Yes. The Commission should require that if the utility is requesting incentive compensation directed at improving power plant availability be recovered from consumers, then there should be either a demonstration that this has been an effective (and that plant availabilities have shown improvement) or the utility should be required to reflect availability improvements in power cost studies. For example, if a company proposes to charge ratepayers $1 million for incentive compensation directed at improving plant availabilities, there should be a reflection of improved availability factors in power cost studies. Certainly, in cases where the trend is a decline, incentive compensation should not be allowed into rates. When such trends are reversed, then incentive compensation recovery may be warranted. However, it is important that utilities only be rewarded for exceptional performance since current ROEs already provide more than adequate compensation.

Q. SHOULD NON-OUTAGE RATE RELATED ADJUSTMENTS BE INCLUDED IN FORCED OUTAGE RATE DETERMINATIONS?

A. No. The OPUC should not broaden the definition of outage rate to include exogenous factors, or to make up for real or perceived deficiencies in power cost models. That is not to say that power cost models should not be changed, or improved when modeling problems are identified. However, if would be far wiser to make corrections to the models to address the real, underlying problems, rather than ad-hoc adjustments to outage rates. There are several reasons for this. First, outage rate computations should be performed in the most objective manner possible, without ad-hoc adjustments. Second, allowing such adjustments in the computation of outage rates makes the process more complicated, adding to the regulatory burden of parties. Third, if the methodology for computing basic inputs can be changed within models, it is tantamount to allowing a change in the power cost model itself. Recent agreements between parties in the PacifiCorp and PGE cases do not allow changes to the power cost models without the agreement of the parties in Transition Adjustment Mechanism ("TAM") or Annual Update Tariff ("AUT") cases. Utilities should not be allowed to accomplish through inputs changes to the model that couldn't otherwise be implemented without the acquiescence of the parties. Finally, when such adjustments are allowed, it is quite subjective and allows utilities substantial latitude in selecting which factors to recognize, and which to ignore.

Q. ARE THERE SPECIFIC OUTAGE RATE ADJUSTMENTS THAT SHOULD NOT BE ALLOWED?

A. Yes. In prior cases, both PGE and PacifiCorp have made upwards adjustments to outage rates to accommodate perceived modeling deficiencies in GRID or MONET. In both cases these companies proposed such adjustments originally because they assumed that their respective models were producing an excess of coal-fired generation as compared to actual results. In both cases, the companies created "phantom outages" increasing outage rates for thermal units above actual values for the four year period.

PGE proposed an ad-hoc change to the formula for computing the Colstrip outage rates in UE 139. This adjustment was made because PGE believed MONET projected levels of generation for Colstrip in excess of actual deliveries.[4/]

PacifiCorp first proposed its ramping adjustment in UE 170 motivated by contention that GRID was producing an excess of coal-fired generation.[5/] However, recent actual results show that GRID underestimates coal-fired

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[4/] Re PGE, OPUC Docket No. UE 139, PGE Exhibit/110-C, Nguyen-Niman-Hager/6-10 (Direct Testimony and Exhibits of Nguyen, Niman, and Hager).

[5/] Re PacifiCorp, OPUC Docket No. UE 170, Exhibit PPL/604, Widmer/2 (Supp. Direct Testimony of Mark Widmer).

generation. For example, in the 12 months ended March 31, 2008 PacifiCorp's coal plants produced 46,319 MWh. For the 12 months ended November 2008 these same coal plants generated 45,878 MWh. In the final update in UE 199, however, GRID showed only 45,545 MWh of coal generation.

Q. DID THE COMMISSION EVER ACCEPT EITHER OF THESE METHODOLOGIES?

A. No. The Commission flatly rejected PGE's phantom outage adjustment in UE 139.[6/]

For PacifiCorp, the history is more complex, but there is no order from the OPUC adopting the ramping adjustment. PacifiCorp has used ramping in some cases, but not others. PacifiCorp withdrew the ramping adjustment in UE 170 (soon after it was proposed) in one of the partial stipulations in that case. In UE 179, the Company proposed a ramping adjustment, but that case resulted in a settlement on net power costs issues which temporarily resolved, but did not decide, the issue of ramping. The Company did not include the ramping adjustment in its UE 191, in the 2007 Wyoming General Rate Case ("GRC") filed immediately afterwards, or in its 2008 Washington GRC.[7/]

The Company again included ramping in UE 199, but made a substantial correction to it in the rebuttal phase. Eventually, the Company agreed to another "black box" settlement leaving the issue undecided. In the end, the thermal ramping issue has never been decided by the OPUC, though the Commission did

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6/ Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (Oct. 10, 2002).

7/ Those cases all followed quickly on the heels of Washington Utilities and Transportation Commission Docket No. UE-061546, which rejected the same ramping adjustment. PacifiCorp has stated elsewhere that the ramping adjustment was left out of the Oregon and Wyoming cases by mistake, though the timing is certainly suggestive.

reject PGE's version of the same proposal. There is no basis to assume the ramping adjustment has ever been included in any prior case in Oregon because ICNU opposed its use in every case. In the only case where the OPUC could have decided the issue (UE 191), PacifiCorp didn't include ramping.

Q. IS MODELING OF THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Based on my thirty years of experience working with various power cost models, this approach is extremely unusual and contrary to standard industry practice. NERC publishes a standard formula for computation of forced outage rates, and the approach proposed by PacifiCorp and PGE does not use the NERC formula.

Q. IS THERE A HISTORY OF PROBLEMS AND ERRORS CONTAINED IN THE PACIFICORP RAMPING ADJUSTMENT?

A. Yes. The ramping adjustment used by PacifiCorp is quite complex, and has been fraught with problems. The ramping adjustment comes from a computer model that the PacifiCorp has been unwilling to provide parties to its cases. Consequently, parties have had little opportunity or ability to test the model's logic. In UE 199 PacifiCorp admitted the method it had been using for the ramping adjustment for several years was simply wrong. This occurred because it was demonstrated in discovery that units that had been started in order to provide reserves (thus running lightly loaded) were assumed instead to be losing energy due to ramping. In the current Utah GRC, Docket 08-035-38, PacifiCorp also admitted to an error in its ramping model calculations.[8/] There are a number of

[8/] ICNU/112, Falkenberg/11 (Utah PSC Docket No. 08-035-38, Data Response Committee of Consumer Services ("CCS") 20.5).

issues concerning the PacifiCorp's methodology, such as the impact of reserve allocations on ramping, and whether ramping losses should be counted after a unit is returned from reserve shutdowns. Another concern is that the Company continues to count as part of ramping losses, loadings less than full nameplate capacity for up to 12 hours after a unit is returned to service. This is well in excess of the time required to restart generators. Further, the ramping adjustment is one sided because it counts energy lost when units are starting up, but ignores the fact that sometimes generators can run in excess of their nameplate rating.

Q. HAS DISCOVERY IN CURRENT CASES UNCOVERED ANY NEW PROBLEMS WITH PACIFICORP'S RAMPING ADJUSTMENT?

A. Yes. To compute its ramping adjustment, the Company determines the difference between the hourly output of a generating unit, and its declared available capacity. In the current Washington general rate case, the Company has again sponsored an adjustment to include ramping for the Bridger units. However, when the hourly generation logs for Bridger were requested, the Company didn't provide any. When asked why the Company couldn't provide this data, when it was ostensibly used for purposes of computing ramping losses, the Company admitted the data used in its ramping workpapers was based on a mathematical formula and "not a reliable measure of hourly generation." ICNU/112, Falkenberg/1-3.

In the end, the ramping adjustment is not supported by precedent, is opaque rather than transparent, and has suffered from numerous errors. The OPUC should not allow this kind of adjustment to be made in the context of outage rate modeling.

Q. PACIFICORP HAS ARGUED THAT A RAMPING ADJUSTMENT IS NECESSARY TO REFLECT THE TIME REQUIRED TO START UP A GENERATOR, WHICH IS NOT NOW CAPTURED IN GRID. PLEASE COMMENT.

A. GRID allows the hourly modeling of resources, and it *could* reflect the start up times required by generators if it had designed proper logic into its model. PGE properly reflects startup times for cycling units in MONET, and there is no reason to interject a dubious and opaque ad-hoc adjustment to outage rates to reflect considerations that could be modeled directly in GRID.

Q. SHOULD FORCED OUTAGE RATE DETERMINATIONS BE ADJUSTED WHEN NEW CAPITAL INVESTMENT IMPROVES RELIABILITY?

A. As a general matter, only after these improvements have shown up in the historical data. Customers may be asked to pay for the investments as they are made, but not see the benefits for several years. While arguably inequitable, it opens up a "can of worms" to make ad-hoc adjustments to address the expected or assumed reliability benefits of new investment. Further, there are likely to be situations where new capital investment arguably degrades reliability. For example, pollution control equipment, such as scrubbers could result in reductions to plant availability. It would be unfair to adopt a policy that favors either reliability enhancement or reliability degradation, but not both. Further, quantifying the impacts of such reliability improvements or degradations would be quite subjective. For these reasons, there should be a prejudice against making ad-hoc adjustments to the computation of outage rates. An advantage of a rolling average is that actual changes to plant reliabilities will be factored into the ratemaking process in due course.

Q. MIGHT THERE BE LIMITED EXCEPTIONS TO THIS PROPOSITION?

A. There may be. One example may be in the case of a resource that has suffered from a chronic reliability problem due to a specific failure mode. If the utility takes steps to address that problem (i.e., through installation of upgraded parts, or a re-design) and charges customers for the associated costs, an adjustment may be warranted. In such cases, the adjustment to outage rates could be computed by removing the specific failure events from the historical outage data. This should allow for an objective, not subjective, measurement of the reliability impact.

Q. WHAT HYDRO AVAILABILITY METHOD SHOULD THE COMMISSION ADOPT?

A. Computation of hydro outage rates should be the same as is used for thermal units. There should, however, be a difference in how the methods should be applied. For storage hydro, it seems unlikely that the utilities will lose any energy during outages. This would only happen with outages long enough to require spillage. An adjustment to hydro capacity may be warranted, because the resources may not be available when required due to the risk of outages.

For run of river hydro, both energy and capacity may be diminished by outages. In such cases, reductions to both may be warranted. However, for both storage and run of river, care must be taken to ensure that the historical water year data used to develop the hydro inputs do not already reflect energy and capacity losses due to outages. If so, then these losses would be "double counted."

Q. WHAT METHODS DO THE UTILITIES CURRENTLY USE TO MODEL HYDRO OUTAGES?

A. PGE does not currently model hydro forced outages. PacifiCorp began using a new method to model hydro outages in UE 199.

PacifiCorp's method has been explored via discovery in recent cases in Oregon and other states. Recently, PacifiCorp has declined to provide the actual workpapers used to determine the GRID inputs. As shown in Exhibit ICNU/112, Falkenberg/4, PacifiCorp only provided instruction on how to compute its hydro outage rates in a recent Washington case rather than the actual workpapers. The problem is that while the instructions are fairly detailed it is apparent that there were many areas where judgment was applied in this analysis. For example, the instructions state that for months with a "high" (high being undefined) number of outage days, outages were scheduled in weekly blocks. For months with less than one outage day "were often ignored or combined." In the various discovery responses provided with ICNU/112, Falkenberg/5-8, various other "business rules" were listed, though there is no clear way to understand how these various rules and procedures were applied. In the end, there is no way in which an outside evaluator could replicate the schedules used by PacifiCorp. This lack of transparency is troubling, given the fact that PacifiCorp has asked the Commission to adopt a new modeling method.

Q. ARE THERE OTHER PROBLEMS WITH PACIFICORP'S HYDRO OUTAGE MODELING?

A. Despite several requests for the actual workpapers in the current Washington case, PacifiCorp has not provided the actual documents used to create the outages currently being used in GRID. It is also troubling that despite ICNU's attempts to replicate the number of outage days computed by PacifiCorp, based on the instructions and data provided, the figures we obtain show far fewer outage days than are being used in GRID. Discovery is continuing on this matter, but at present there is no resolution to this dispute.

Q. ASSUMING A RESOLUTION OF THE DATA AND WORKPAPER ISSUES, DO YOU HAVE ANY GENERAL COMMENTS CONCERNING THE PACIFICORP METHODOLOGY?

A. Yes. PacifiCorp's methodology amounts to modeling of monthly planned and unplanned outage rates for hydro resources. Use of monthly outage rates for planned outages is reasonable given that planned outage are scheduled in advance, and should occur during time of the year when costs are low.

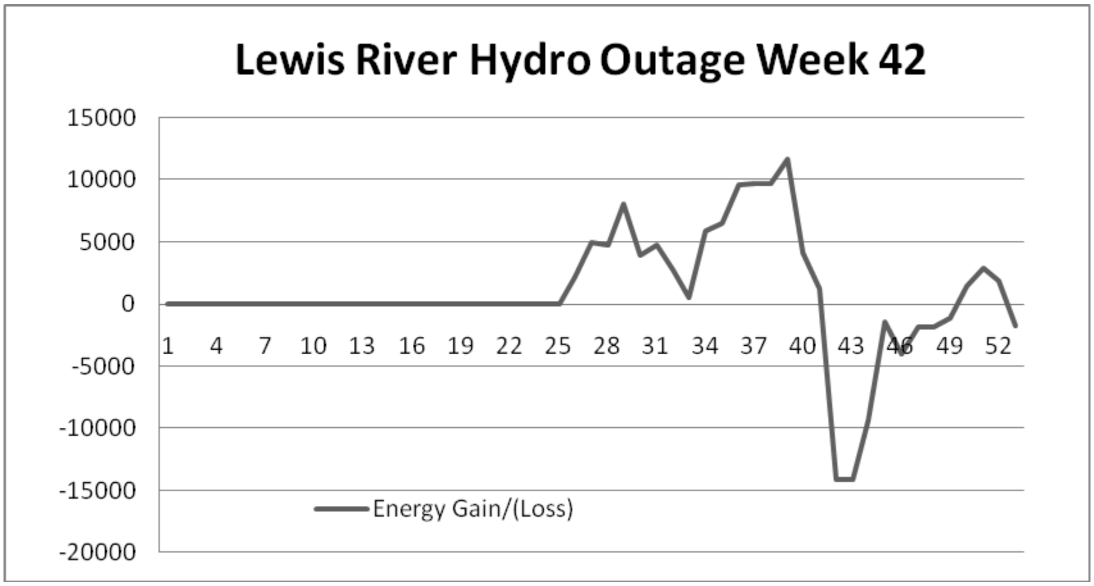
The use of monthly unplanned outage rates is questionable, especially given that PacifiCorp has abandoned use of monthly unplanned outage rates for thermal units. There is no basis for assuming that unplanned outages for hydro units follow a monthly pattern, when thermal units do not. A far more logical approach would be to model unplanned outages as occurring with equal likelihood during all months, and retain the current monthly differentiation of planned outages.

Q. DO YOU SEE ANY SERIOUS PROBLEMS IN THE APPLICATION OF THE PACIFICORP HYDRO OUTAGE MODELING METHODOLOGY?

A. Yes. The method can systematically remove energy from a test year. The problem occurs because the hydro outages are placed into the Vista model, which then reshapes the available energy to optimize the schedule based on the forward price curve. This is a reasonable approach because given the knowledge of a pending outage schedulers will likely change the planned operation. This may entail taking some of the energy "early" (before the outage) and some "later" (after the outage). However, no energy should be lost or gained in the process except for the very unlikely case of spillage (which is not going to occur under normalized conditions). Unfortunately, in the PacifiCorp process, some energy is shifted beyond the end of the test year, resulting in a net reduction in available energy. While that is certainly a plausible outcome, it stands to reason some energy from outages occurring before the test year will be shifted into the test year. However, outages occurring before the test year may not be considered in the PacifiCorp modeling.

For example, if a planned outage occurred late in a 2010 test year, some of the hydro energy would be shifted to 2011. However, there should also have been comparable outages modeled in 2009, which would be shifted into the 2010 test year. It does not appear this occurs under the PacifiCorp method.

In discovery in Utah Docket No. 07-035-93, the Company provided an analysis showing how its method would apply in the case of a particular outage. ICNU/112, Falkenberg/9-11. The data illustrates that under the PacifiCorp method, energy is indeed shifted beyond the end the test year, but no energy is shifted into the beginning of the test year. The figure below illustrates this problem. In this case an outage on the Lewis River was scheduled around week 42 of the test period. The data shows some energy was taken early, and some late, but in the end, about 13% of the energy was not returned. As the figure shows, this energy was moved to beyond the end of the test year, but no offsetting energy was moved in to the start of the test year from outages in a prior year. Staff identified problem of this reduction of hydro energy due to the forced outage rate modeling used in GRID, and the Company acknowledged this occurred in UE 199.[9/]



Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE MODELING OF HYDRO OUTAGES?

A. There are three serious problems with PacifiCorp's hydro outage modeling: 1) lack of transparency and satisfactory documentation; 2) use of monthly outage rate modeling; and 3) exaggeration of the impact of outages on available hydro generation. Until PacifiCorp can realistically solve all of these problems, it should not be allowed to apply its hydro modeling method in GRID.

Q. WHAT WIND AVAILABILITY REPORTING METHOD SHOULD THE COMMISSION ADOPT?

A. Owing to Oregon's and Washington's Renewable Portfolio Standard ("RPS"), utilities are investing staggering sums of money in wind resources. Whether this is money well spent will largely depend on the energy production of these resources. To help the Commission, and policy makers understand the true economics of

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9/ Re PacifiCorp, OPUC Docket No. UE 199, PPL/106, Duvall/20 (Rebuttal Testimony of Gregory N. Duvall).

wind generation, detailed availability data should be collected. ICNU proposes that the same level of reliability data be collected for individual wind turbines, as is the case for individual thermal generators. Exhibit ICNU/106 shows a copy of the type of data collected for thermal plants. This identifies each outage, or deration, event, cause of the event, lost energy, duration, and a standardized code. At this time, NERC may not have standardized codes for wind, but it would be helpful to use preliminary codes.

Q. HOW SHOULD WIND AVAILABILITY BE APPLIED FOR POWER COST STUDIES?

A. The output of wind resources can be thought of as having two components: availability of "energy" and reliability of machinery. In many respects wind resources are similar to run of river hydro. They both depend on the vagaries of weather and climate, but the energy is harnessed through the use of a relatively simple technology. Wind has an added reliability advantage in that large numbers of identical machines are used. Ultimately, this should help promote mechanical reliability. Thus, wind generation marries the unreliability of nature with high reliability and redundancy of machinery.

Aside from prudent site selection, there is nothing that can be done about the "energy supply" side of the equation. However, mechanical reliability is something that can be influenced by the utility. ICNU proposes that utilities be required to use the same wind output assumptions for power cost models as were used in the resource acquisition process. After a sufficiently long period of time, there should be enough wind data to make better wind forecasts, and stable forecasts of reliability the inputs used in the forecasting process should be revisited.

Q. WHAT ARE PLANNED OUTAGES?

A. Planned outages represent events when generators are taken out of service for routine scheduled repairs and maintenance. Plants are typically taken down once per year for scheduled work, while individual units may only be taken down once every four to six years. Normally, this work is scheduled in the spring when demand and market prices are at their lowest levels.

Q. WHAT METHODOLOGY SHOULD THE COMMISSION USE FOR PLANNED MAINTENANCE OF THERMAL, HYDRO AND WIND RESOURCES?

A. The methods used by the Commission should ultimately be the same for all types of resources. However, for the next several years or more, wind resources should be modeled based on the forecasts used in project evaluations and the IRP. Eventually, wind should become a mature technology, with substantial performance data available, and it would then be possible to make better assumptions at that time. As discussed above, there is much work that needs to be done before PacifiCorp is accurately modeling hydro planned outages.

Q. WHAT ARE THE KEY GOALS THE COMMISSION SHOULD CONSIDER IN SELECTING A METHODOLOGY FOR PLANNED OUTAGE MODELING OF THERMAL AND HYDRO RESOURCES?

A. The method used should be transparent, verifiable and devoid of perverse incentives. Currently, PGE and PacifiCorp use different methods for determining planned outage forecasts. PGE applies its most current forecast of the actual schedule for use in the test year. PacifiCorp uses a four year rolling average to determine test year requirements and then develops what it considers to be a "normalized" schedule of outages. Both approaches, as implemented by the respective companies, have certain drawbacks.

Q. WHAT ARE THE PROBLEMS ASSOCIATED WITH USE OF A FORECASTED SCHEDULE?

A. The first problem is that planned outage schedules can and do change in response to external events. A forecast prepared more than a year in advance may not reflect what actually happens. A second problem is that such forecasts are not verifiable in any real sense. It would be very difficult to determine, for example, if the utility simply proposed an unrealistic, high cost schedule of planned outages for purposes of increasing cost recovery. There is simply no way to determine if the forecast is realistic or not, as the duration and timing of planned outages can change dramatically from year to year. This is really an illustration of the problem of perverse incentives. The incentive for the utility is to make *forecasts* that overstate planned outage activities and costs and then to skimp when it comes to the actual planned outages.

A further problem is that utilities would then need to remove planned outages from the historical database (i.e., the four year period.) There would be a temptation to reclassify events "after the fact" as unplanned, rather than planned.

Q. ARE THERE EXAMPLES THAT ILLUSTRATE THESE PROBLEMS WITH PGE'S USE OF PROJECTED OUTAGE SCHEDULES?

A. Yes. Confidential Exhibit ICNU/107 shows a comparison of the actual planned outage durations from 2004-2007 for PGE's generators, to the forecasted figures used in MONET during that time. The figures show that there were differences between the assumed the average outage durations for Boardman, Colstrip and Coyote. Overall, PGE over-predicted scheduled outages as compared to actual.

Further, PGE [redacted]

There have also been other situations involving the problems discussed above. In UE 172, PGE included an outage for the Sullivan hydro plant that had already been included in the prior RVM case, but which did not take place. Parties objected to this treatment which effectively counted costs for the same outage twice. PGE argued in response that a long outage of the same plant in a prior year was not counted as part of the RVM.

Further, in the case of a longer than expected planned outage at Boardman, PGE reclassified (after the fact) the extension period of that event as being due to a forced outages. That resulted in an increase in NVPC because the unplanned outages are part of the four year average used in MONET, while planned outages are removed from the four year average and replaced with a forecasted schedule.

Finally, in UE 198, parties to the PGE case questioned the assumed timing of a long Boardman outage planned for 2009. This issue was ultimately resolved though the settlement, which was predicated on an assumed shift in the schedule.

None of this is to suggest what the "right" or "wrong" answer was in the above situations. However, it illustrates that when forecasted schedules are used, there are problems with verification, the accuracy of the forecast outcomes, and potential adjustments to the historical data. Use of a purely forecast schedule does not make the process more transparent, more efficient, or more equitable. It also does not remove the controversy surrounding modeling of planned outages from rate cases. Indeed, as the examples above shows, there have been many such problems in recent years.

Q. WOULD THE ABOVE PROBLEMS HAVE BEEN AVOIDED IF A FOUR YEAR AVERAGE WAS USED TO DETERMINE UNPLANNED OUTAGES FOR PGE?

A. For the most part they would. There may still be an issue concerning the proper classification of the longer than expected Boardman outage, but that would have been a less important issue because it would have been included in either planned or forced outages.

Q. WHAT IS YOUR RECOMMENDATION?

A. There is no way to objectively "verify" a forecast. Use of a multi-year history for determining the planned outage assumptions would place planned and unplanned outages on an equal footing. This would reduce incentives to misstate forecasts and would avoid some of the problems and issues that have arisen in prior cases. For this reason, I recommend the Commission adopt use of normalization technique based on the same multi-year rolling average as is used for unplanned outages.

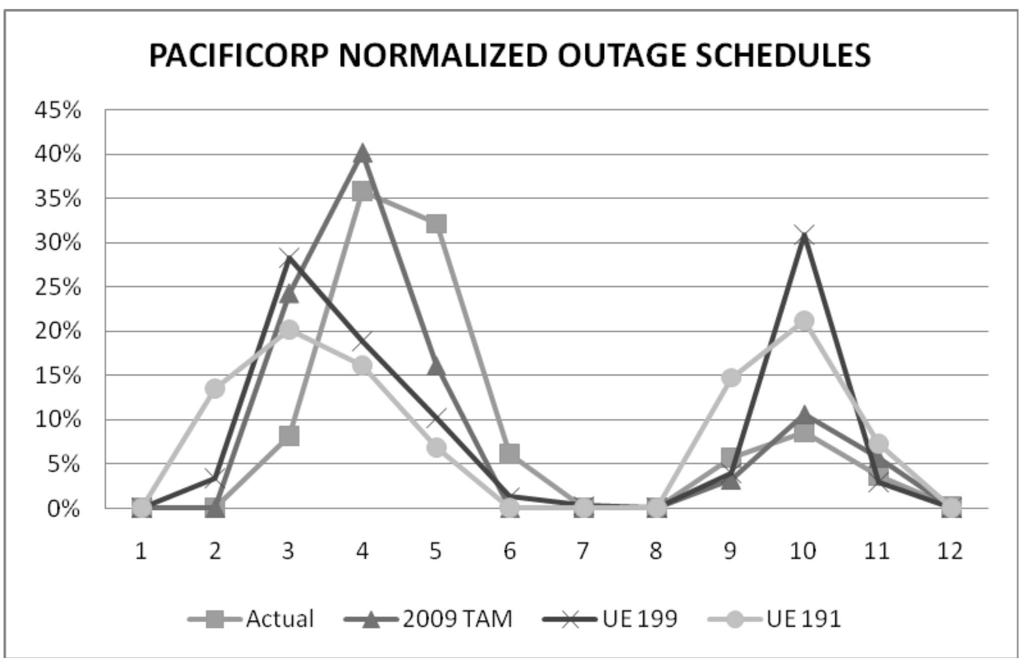
Q. RETURNING TO THE GOALS YOU DISCUSSED EARLIER, ARE THEY WELL SERVED BY USE OF A MULTI-YEAR ROLLING AVERAGE NORMALIZATION METHOD?

A. Yes. The data concerning actual planned outages during the historical period is readily available, so that the timing and duration of all actual outages can be verified. Further, if there are any "perverse incentives" it would not be to skimp on planned outages. Money and time committed to planned outages is well spent as it occurs during times when replacement costs are low, but improves reliability when replacement costs for forced outages are much higher.

Q. PACIFICORP BASES ITS NORMALIZATION ON THE FOUR YEAR ROLLING AVERAGE. ARE YOU IN FULL AGREEMENT WITH THE PACIFICORP APPROACH?

A. No. While I agree with PacifiCorp's methodology for determining the *normalized duration* of planned outages, I don't agree with the manner in which they develop the assumed *normalized schedule* of planned outages.

PacifiCorp uses what it calls a "normalized" maintenance schedule with outage. Unfortunately, the schedule (timing of outages) input assumptions used in GRID have typically not been a reasonable representation of a normalized outage schedule, as is illustrated in the chart below and have been unstable from one year or case to the next.



Q PLEASE EXPLAIN THE FIGURE ABOVE.

A. The chart compares the schedule assumption used by PacifiCorp in some of its most recent rate cases as taken from GRID. The graph shows the historical percentage of scheduled coal outage energy[10] for each month of the calendar year due to planned outages based on the 48-month period ended June 30, 2008.[11] The figures shown represent the outage schedules assumed in UE 191, UE 199 as well as the current 2009 TAM filing. The figures show the flexibility PacifiCorp's methodology allows in determining is "normalized" outage schedules. It is important to recognize that PacifiCorp presented all three of these schedules in recent rate filings, and contended they represented a reasonable "normalized" schedule of outages. In addition, Mr. Duvall testified in the 2009 TAM filing that the Company was using the same methodology as in UE 199 for determining planned outages. Re PacifiCorp, OPUC Docket No. UE 207, PPL/100, Duvall/8 (Direct Testimony of Gregory N. Duvall).

It is apparent from the chart that actual planned outages have traditionally been scheduled to coincide with the low market price periods in the spring and fall. April, May and June typically have the lowest market prices, and PacifiCorp traditionally has scheduled 74% of its maintenance during these months. Data for previous time periods shows this to be a very stable pattern over time. I discussed this matter with PacifiCorp executives at a technical conference conducted in February 2008. It was stated by the PacifiCorp representatives that the goal of outage scheduling was to minimize costs by placing outages in the "preferred window" during the spring.

10/ This would be the amount of coal-fired energy PacifiCorp would need to replace in order to make up the generation lost due to planned outages. Because gas fired peaking units have much higher operating costs, and are frequently shut down the schedule of these kinds of plants is not as significant.

11/ This was the four year period used by PacifiCorp to compute all outage rates in its current 2009 projections. Use of data from earlier four year periods shows little change in the shape of the actual data plotted on the graph.

In contrast, the schedule assumptions used in PacifiCorp's various GRID studies in recent cases have shown wide variation. In UE 191, PacifiCorp assumed there would be substantial coal plant outages in the winter months of February and March, as well as higher cost periods in fall. In its 2007 Utah GRC (Docket No. 07-035-93), it was assumed coal plants would be on outage in January. The PacifiCorp outage schedule proposals were ultimately rebuked by the Utah Commission in that case.

In UE 199, PacifiCorp modified its schedule assumptions to move outages from the winter months to the fall, another period it has traditionally preferred to avoid, and concentrated most of the rest of the outages in late winter and early spring. Finally, in its most current studies the Company moves its schedules closer to actual schedules, but still assumes too much outage energy early in the year.

The significance of these observations is that the *methodology* used by PacifiCorp to determine its "normalized" outage schedule is extremely unstable, and can be judgmentally adjusted to produce a wide range of results. In all of these cases the PacifiCorp contended the final results were a reasonable normalized outage schedule, even the Utah 2007 GRC schedule that placed coal units on outage in the winter months. In fact, in that case, PacifiCorp suggested it would skew normalized power cost results if coal outages were not scheduled in the winter.[12/] Clearly, the PacifiCorp method provides for substantial latitude in determining what constitutes a "reasonable" normalized schedule.

Q. HOW DOES PACIFICORP DEVELOP THE PLANNED OUTAGE SCHEDULE FOR GRID?

A. The approach actually used in GRID is an arbitrary and essentially mechanical process that does not appear to be based on historical or expected outage schedules, market price curves or other scheduling considerations. While the spreadsheets that implement the schedules list a variety of considerations, those are not always tested or applied. These constraints amount to little more than "window dressing." Rather, PacifiCorp simply makes assumptions about when a few outages will occur, and then keys other outages off of those assumed dates. The PacifiCorp method is unstable, opaque and highly subjective. Even though PacifiCorp has obviously changed its scheduling assumptions substantially in recent cases, underlying "methodology" never really changed. Instead, it merely modified certain judgmentally determined driving inputs. This poses a significant

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12/ The Company's excerpted response to Data Request CCS 5.1 in UPSC Docket No. 07-035-93 stated as follows CCS Data Request 5.1

<u>NPC GRID Modeling.</u> MDR-2.57 contains a worksheet that lists considerations related to planned outage scheduling. It states the cold weather/high load months are to be avoided for planned outages for Hunter, Wyodak and other plants, and that the period late November through mid February are to be avoided. However, the GRID data base shows planned outages for Cholla, Craig, Hayden, Hunter and Naughton in the months of January and February 2009. Further, during the four-year period ended June 2007 none of these units actually had outages scheduled in January or February. Given the criteria delineated in the worksheet provided as part of MDR-2.57, does the Company believe that the normalized outage schedule included in the GRID database is reasonable?

Response to CCS Data Request 5.1
Yes. For normalized ratemaking purposes, GRID is required to schedule planned outages for all plants during a one year period. To do otherwise would result in planned outages at certain generating units being ignored in the determination of normalized power costs. In actual practice, planned outages can be staggered across multiple years; however this cannot be reflected in GRID without skewing normalized power costs.

problem in cases such as the TAM because absent continuous scrutiny, PacifiCorp may at any time change it outage schedule assumptions and revert to unrealistic outage schedules. It creates an additional burden on the parties to constantly track PacifiCorp's mercurial outage scheduling assumptions.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PLANNED OUTAGE SCHEDULE ISSUE?

A. There is a very simple resolution to the matter. PacifiCorp bases its normalized outage energy requirements on the most recent four years of historical data. The normalized schedule adopted should reflect the actual schedules used in that same period.

A very reasonable approach would be to apply each of the four actual schedules used during the four-year period in GRID. To do this one would analyze four distinct outage schedules for the one-year periods. By computing the average cost of actual outages over the four-year period it would be possible to develop a power cost study that provides realistic normalized planned outages. ICNU recommended this method in UE 199. Because the case was settled with a "black box" there was no decision regarding outage schedules.

Q. DID PACIFICORP HAVE ANY CRITICISMS OF THE USE OF FOUR ACTUAL PLANNED OUTAGE SCHEDULES IN UE 199?

A. PacifiCorp did not embrace the approach. The most significant complaint raised was the adoption of this methodology would be difficult since it requires multiple GRID runs, complicating development of screens used to mitigate the commitment logic error in GRID. Use of four actual schedules as opposed to one normalized schedule is somewhat more cumbersome, but it does provide the most useful test of any schedule that has been nominated. I consider it to be the "gold standard" for judging the reasonableness of results from any particular outage scheduling methodology.

I investigated varying methods to develop a single schedule that uses all outages that occurred during the four year period. I was aided in this effort by the critique provided by Mr. Duvall in his recent Utah rebuttal testimony. Mr. Duvall evaluated a number of methods for development a single schedule based on the actual historical planned outage events. Building on his efforts, I have developed a possible solution to develop a single schedule for application in the model.

Q. IN DEVELOPING A SINGLE SCHEDULE BASED ON THE ACTUAL WHAT ARE THE GOALS?

A. I believe the following goals are appropriate:

1. The results should track the average of the four actual schedules as closely as possible. This includes preserving the day of the week when the outage starts.
2. The methodology should provide for the same amount of outage energy by unit as actually occurred during the four year period.
3. The methodology should follow the historical distribution of outage energy as closely as possible.
4. The method should be transparent and objective and not too difficult to apply.
5. In cases where a full four years of data is not available for specific units, historical and projected outage patterns should be used to develop realistic schedule assumptions (e.g., Currant Creek, Lake Side, Port Westward).
6. The final cost of the outage schedule should be based on the use of the actual four schedules, while a purely financial adjustment should be applied to account for any differences between the single schedule used and the four actual schedules.

Q. HAVE YOU DEVELOPED A METHODOLOGY THAT SATISFIES THESE GOALS?

A. Yes. The method I propose would implement a planned outage for each event that actually occurred in the four year periods with duration equal to one fourth of the actual duration, rounded to a whole number of days. The timing of each outage should be centered about the mid-point of the actual outage as it occurred during the four year period. This produces a single schedule which follows the historic pattern of outage scheduling, and which can be shown to produce results close to the use of the four actual schedules.

Q. HOW DID YOU DETERMINE THE START DATE FOR NORMALIZED OUTAGES?

A. There are a number of plausible alternatives, but in the end, only a few make sense. Assume hypothetically one had an actual outage event that started on May 16, 2005, lasting 24 days, and one wished to apply it to a 2009 test year. In the normalized schedule, the event would be 6 days long (24/4=6). The most significant question would be what is the proper starting date? For the method to make sense, the normalized outage should start on a day that at least falls within the dates of the original planned outage event. The logical possibilities are illustrated on the chart below. These include: 1) Starting on the earliest possible date (the date of the original outage); 2) Starting on the latest possible date (arranging the event to end on the day the original event ended); 3) Starting at the mid-point (i.e., half way between the original start and end dates); and 4) Centering the outage about the mid-point (so that the mid-point of the normalized event is at the mid point of the actual event).

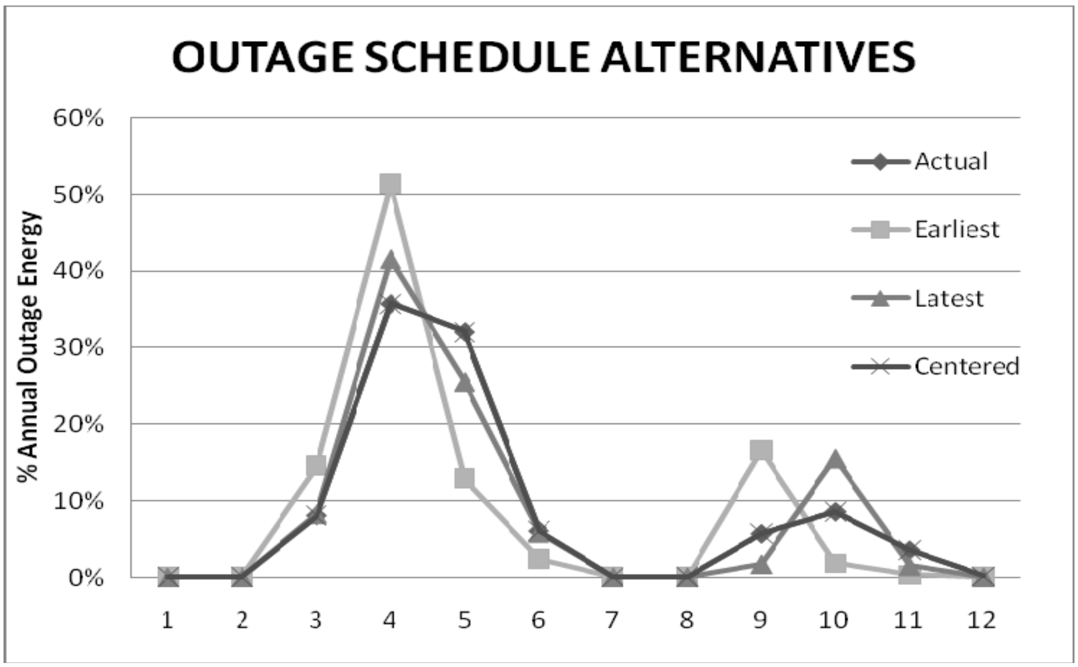
		1	3	5	7	10	12		13	15	17	19	21	23	24
	Start	16-May	18-May	20-May	22-May	25-May	27-May		28-May	30-May	1-Jun	3-Jun	5-Jun	7-Jun	8-Jun
Actual Event	16-May	<---------	----------	----------	----------	----------	----------		----------	----------	----------	----------	----------	----------	-------->
	24 Days														
Normalized								*M*							
Earliest Start	16-May	<---------	----------	-------->				*i*							
	6 Days							*d*							
Latest Start	3-Jun							*p*				<---------	----------	----------	-------->
								o							
Mid Point	28-May							*i*	<---------	----------	----------	-------->			
								n							
Centered	25-May					<---------	----------	*t*	----------	-------->					

Q. PLEASE EXPLAIN THE VISUAL AID ABOVE.

A. This presents the four logical schedules based on a hypothetical 24 day outage starting on May 16. The earliest possible start date would be May 16, 2009, resulting in a six day outage ending on May 21. The latest start date would assume a June 3, 2009 start date, and an end date of June 8, 2009. The mid-point alternative would result in a May 28, 2009 start date, while the final "centered" scenario would result in a May 25, 2009 start date.

Of these scenarios, only the last two make sense. The use of the earliest possible date is not supportable because it would move outage energy to the earliest plausible date, thus biasing power costs upwards. Likewise, the use of the latest possible date would move the events to times later than they actually occurred, biasing power costs downward. These results are confirms by comparison of these scenarios to the average NVPC of the four actual outage schedules. The figure presented below shows the distribution of the outage energy based on all four scenarios.

The remaining two scenarios are plausible, but the use of the mid-point of the outage event would tend to move outage energy into the last half of the actual event. This leaves the "centering" option, which would tend to produce outage schedules that distribute the outage energy right about the mid-point. When combined with an adjustment to preserve the weekday of the outage event, this produce a result that matches the historical outage energy pattern so well that the figure below shows they are indistinguishable. Further, this scenario produces a final NVPC result quite close to the four actual outage events. This means the financial adjustment required in this method would be small.



Q. HAVE YOU PREPARED AN ANALYSIS THAT DEMONSTRATES THIS?

A. Yes. I developed an analysis that compares the currently assumed GRID schedules for 2009 prepared by PacifiCorp, to the results of the single schedule and with the results from the four actual schedules. In the end, the two approaches were in close agreement, while the PacifiCorp assumed schedule is clearly an "outlier."

Q. ARE THERE OTHER ADVANTAGES TO THIS METHODOLOGY?

A. Yes. The use of the actual schedules is not subjective as compared to development of a schedule based on the PacifiCorp approach, or any other method. The data is readily available discovery and easy to apply and interpret. The number of outage days and outage energy is the same for the normalized schedules and the actual four-year average. As the four-year average underlies PacifiCorp's planned outage requirements, this is a logical extension of the PacifiCorp methodology, which has been accepted by the OPUC for many years. Finally, because all four of these schedules were actually used by PacifiCorp, there is no basis to suggest they were "result oriented" (i.e., solely designed to align with low market prices) impractical, infeasible or otherwise improper. This proposal provides a transparent and realistic methodology for outage scheduling which I recommend the OPUC adopt.

Q. ARE THERE ANY UNITS FOR WHICH THIS APPROACH COULD NOT BE APPLIED DIRECTLY?

A. Currant Creek and Lake Side were online for only part of the four-year period. PacifiCorp uses both prior and projected outages of these plants to determine the annual outage requirement (number of days) for these units in their current projections. Because PacifiCorp also has used and expects to use spring and fall outages for these plants, I recommend use PacifiCorp's planned fall outage assumption for Lake Side, but that a spring outage be used for Currant Creek. In a few years there will be sufficient historical data to eliminate the need for these assumptions.

Q. PLEASE DISCUSS THE RESULTS OF THIS ANALYSIS.

A. The table below presents these results. This was based on testimony I filed in the current Utah proceeding based on a 2009 test year. Most of the data shown was filed in my direct testimony in that case, with the remainder having been prepared for surrebuttal. The figures shown are compared to the original GRID schedule. The results demonstrate that PacifiCorp has overstated the cost due to planned outages in GRID and that the single composite schedule produces results comparable to the average of the four individual schedules.

Planned Outage Schedule Impact

Planned Outage Scenario	GRID NPC	Change from Company Base	% Change	Planned Outage Energy (mWh)	Change	
Company Base	1,053,297,584			6,848,761		
2004-2005	1,040,410,071	(12,887,513)	-1.2%	6,393,476	-455,285	-6.6%
2005-2006	1,055,960,627	2,663,043	0.3%	7,118,887	270,126	3.9%
2006-2007	1,066,773,305	13,475,721	1.3%	7,373,112	524,351	7.7%
2007-2008	1,040,461,743	(12,835,841)	-1.2%	6,512,739	-336,022	-4.9%
Four Year Average	1,050,901,437	(2,396,148)	-0.2%	6,849,553	792	0.0%
GRID Run Using Composite Schedule	1,050,352,594	(2,109,076)	-0.2%	6,844,986	-3,775	-0.1%
Financial Adjustment		(287,072)				

Q. THE TOTAL NPC FIGURES SHOW A WIDE COST VARIATION DURING THE FOUR-YEAR PERIOD. PLEASE DISCUSS THE IMPLICATIONS OF THIS.

A. Outages are scheduled on a cyclical basis and the costs during any single year will vary. The first and last years were periods scheduled relatively few planned outages. The third year was a high cost period which the table shows had more scheduled outages. This table actually provides a good reason for normalizing maintenance instead of using a single year. The results can vary substantially from one year to the next based on the actual outage schedule. This is why it is reasonable for PacifiCorp to use a four-year average to develop the amount of planned outage energy to include in the test year. I recommend the OPUC adopt my proposed methodology for computing the planned outage schedule to be used in GRID as well as by PGE in its MONET model.

Q. ARE THERE OUTAGE OR DERATION EVENTS THAT DON'T FALL NEATLY INTO EITHER THE CATEGORY OF PLANNED OR UNPLANNED (FORCED) OUTAGES?

A. Yes. NERC defines maintenance outages and derations as those events that can be deferred to beyond the next weekend, but not longer than until the next planned outage. Under the NERC formula, such events are not considered part of the forced outage rate. The timing of these events is quite important because utilities can (and do) minimize cost by moving such events to weekend or off peak periods when replacement power costs are low.

Q. HOW DO PACIFICORP AND PGE TREAT DEFERRABLE EVENTS IN COMPUTING OUTAGE RATES IN THEIR POWER COST MODELS?

A. Both companies include these events as part of their unplanned outage rate calculations. Because these events can occur at various times, it is probably impractical to attempt to model them as scheduled events such as planned outages. Consequently, I have no quarrel with their inclusion in unplanned outage rates. However, there should be some recognition of the deferrable nature of such events.

Q. DISCUSS THE HISTORY OF MODELING OF DEFERRED MAINTENANCE AS IT PERTAINS TO PGE AND PACIFICORP.

A. So far as I know, PGE has never reflected the timing of deferred outages in any explicitly manner in its modeling.

Prior to UE 170 PacifiCorp included all deferrable outages in the weekend outage rates it modeled in GRID. During the course of UE 170, PacifiCorp proposed an "update" to its NPC study that changed the calculation of the weekend outage rate to reflect only the portion of lost generation that actually occurred during the weekend. In the Third Partial Stipulation in UE 170, however, PacifiCorp agreed to withdraw the adjustment. PacifiCorp included this new weekend outage rate modeling approach in UE 179, UE 191, and initially in UE 199. However, in UE 199, PacifiCorp changed the outage rate modeling to eliminate the weekend, weekday differentiation of outage rates in its July filing. PacifiCorp's evolving treatment of this issue seems rather opportunistic and has increased normalized power costs.

UE 199 and UE 179 settled power cost issues, while the issue was not litigated in UE 191. As a result, there is no OPUC ruling adopting the PacifiCorp's latest approach. I recommend the Commission require PGE and PacifiCorp to explicitly model deferrable maintenance outages in a manner that recognizes these events tend to occur on weekends, or in other off-peak periods. The most straightforward approach would be to include all deferrable maintenance outages in the weekend, or LLH. Given the deferrable nature of these events, simply including them in off-peak or weekend hours would be quite reasonable. An alternative is to differentiate outage rates by weekend and weekday, or between on and off-peak periods.

Q. WHAT IS THE PREMISE OF THE CURRENT MODELING METHODS USED BY PGE AND PACIFICORP?

A. Most recently both companies are using a single annual average outage rate for all types of unplanned and deferrable outages. This has the effect of assuming that deferrable outages occur with equal frequency in either weekend, weekday, on or off-peak periods. In effect, the companies are assuming these events occur at random, in exactly the same manner as random, unplanned outages or derations. This is an unrealistic assumption that the OPUC should reject.

Prudent operating practices require utilities to schedule such events during low demand, or low cost periods, whenever possible. For example, if a problem requiring maintenance were to occur during a summer heat wave, plant managers could defer the repairs until night time, a period of milder weather (and lower market prices) or at least until the next weekend. In any case, lower market prices would prevail, and replacements costs would be lower.

Q. DO YOU HAVE ANY EVIDENCE TO SUPPORT THESE OBSERVATIONS?

A. Yes. Exhibits ICNU/108 and ICNU/ 109 show a time differentiated analysis of deferrable outages and derations for PacifiCorp generators over a recent four year period. The data (provided by the Company on a non-confidential basis in the current Utah proceeding) clearly shows that a disproportionate share of these events occurs during LLH, and/or during weekends.

Exhibit ICNU/108 shows that while the LLH are only about 44% of all hours, 54.7% of maintenance outage and duration hours occur during that period. Further, 77% of the coal plants show more hours maintenance outages and derations occur in LLH than in HLH. Also, more than 92% of the coal plants have a “disproportionate” share of maintenance outages hours in the LLH (i.e., more than 44% which would occur if the timing were simply by chance.) This clearly shows that deferrable events are preferentially scheduled during off peak times.

Similar results emerge for the analysis of weekend and weekday outage hours. Exhibit ICNU/109 shows the same analysis differentiated between weekends and weekdays. The figures show that while weekends are only 28.6% of all hours, 42.8% of deferrable hours occur during weekends. Further, more than 80% of PacifiCorp's coal plants have a disproportionate amount of deferrable maintenance occurring during weekend hours. It is clear from this data that maintenance outages are not simply random events that can occur at any time, like forced outages, rather, they are scheduled preferentially to occur in off peak, or low cost periods.

Q. WHAT DOES THIS MEAN FOR OUTAGE RATES OVERALL?

A. At a minimum, outages rates should reflect a weekend/weekday split, or a HLH/LLH split. This is necessary to reflect actual operational practices. Failure to do so results in an overstatement of power costs, and would essentially assume that PGE and PacifiCorp would be imprudent because they would schedule deferrable outages at random times. The Commission has already rejected the assumption that a company would operate imprudently on a normalized basis, as discussed in the previously quoted portion of the Order from UE 191.

Q. DO YOU HAVE AN ANALYSIS OF CONCERNING WHETHER OUTAGE RATES OVERALL ARE HIGHER ON WEEKENDS THAN ON WEEKDAYS?

A. Yes. For PacifiCorp, more than 88% of the Company's thermal resources have higher weekend than weekday outage rates. A comparison of weekend and weekday outage rates is shown on Exhibit ICNU/110. This is based on data provided by the Company on a non-confidential basis in UE 199. This clearly shows that the impact of deferrable outages is to increase outage rates on weekends as compared to weekdays. I believe this provides additional proof that there should be a differentiation of outage rates by weekend or weekday, if not LLH and HLH.

Q. THIS MATTER WAS LITIGATED IN OTHER CASES. PLEASE DISCUSS THE ISSUES RAISED BY PACIFICORP.

A. In UE 199 and Utah Docket No. 07-035-93 PacifiCorp presented data concerning average monthly outage rates for a five year period. The PacifiCorp witness argued that visual inspection of outage rate data showed no discernable difference between weekends and weekdays. Re PacifiCorp, Docket No. UE 199, Duvall PPL/110. It would not surprise me if the Company were to resubmit this analysis in the present case. While Mr. Duvall's graphs perhaps didn't show a discernable pattern, his underlying does show a highly significant pattern exists, albeit not one that is immediately obvious to the naked eye. Indeed, the problem with that approach was that one couldn't "see the forest for the trees."

Q. DID YOU ANALYZE MR. DUVALL'S DATA?

A. Yes. To determine whether there was a difference between weekend and weekday outage rates I examined Mr. Duvall's data. This data consisted of more than 2500 monthly observations for more than 40 generators. From this mountain of data there were ample observations to perform a valid statistical analysis.

To test whether there was a statistically significant difference between the weekend and weekday outage rates I defined the variable d as the difference for each unit-month between the weekend and weekday outage rates:

$$\mathbf{d = WD_{EFOR} - W_{EFOR}}$$

If d is positive, then the weekday EFOR is higher than the weekend EFOR. If d=0, then there is no difference. Since outage rates vary substantially, the value of d fluctuates from unit to unit and from month to month. As one would expect, there is a lot of random noise contained in this data. What we wish to determine is whether there is an underlying pattern in the data. In other words, is d greater than zero, and if so, is this a statistically significant result, or one that could have happened merely by random chance.

To test the significance of the results, I computed the variance of d using the following formula:

$$\mathbf{Var(d) = var\,(WD_{EFOR}) - 2covariance(WD_{EFOR}, WD_{EFOR}) + var(WD_{EFOR})}$$

Based on the Central Limit Theorem,[13/] the variance of the sample mean for d, is equal to the Var(d)/N, when N is the sample size. Note that this is true irrespective of whether d itself is normally distributed or not.

The null hypothesis we wish to test is d=0 (i.e., whether there is no difference between weekend and weekday outage rates). Based on the sample data, however, d=1.1, meaning that weekend outage rates averages 1.1% higher than weekday outage rates. From Mr. Duvall's data the average weekday outage rate is 6.6%, while the average weekend outage rate was 7.7%.

The sample variance (var(d)/N) was quite small, however, 0.034 because we had a very large sample size (N=2545). This results in a sample standard deviation (the square root of 0.034) of only 0.184, meaning that 1.1 is some 5.81 standard deviations from 0. This is an exceptionally improbable outcome if the null hypothesis were true (that there was no weekend or weekday differentiation in

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13/ The Central Limit Theorem is in many ways the foundation of modern statistics. It states that for any distribution with a finite mean and variance, if one has a sample of sufficient size, the sample mean can be approximated by a normal distribution.

outage rates). Indeed, the confidence level is well over 99.99. This means that while there may not be an apparent difference in weekday and weekend outage rates when viewed on a month by month, unit by unit basis, there is a small but extremely significant difference when all the data is examined. This was not revealed in a mere visual inspection of Mr. Duvall's data, but is quite apparent when a proper statistical technique is employed.

Q. WAS THIS ISSUE DISCUSSED IN THE WORKSHOPS IN THIS CASE?

A. Yes. I pointed some of this out during those discussion, but the utility representatives seemed skeptical. One argument made was that outages take too long to schedule preferentially on weekends or off peak. There was, however, no data presented, however, supporting any of these statements. In reality, such outages (and derations) do not necessarily entail long periods of time. In fact, of the thousands of events that occurred in PacifiCorp's plants from 2004-2007 (again based on public data provided in UE 199), only about 3% lasted longer than 48 hours, and only about 5% lasted longer than 24 hours. As derations are a common way of addressing deferrable problems, it should be clear that off peak periods provide the least cost way in which to address whatever problems may be occurring. In the end, this is nothing more than common sense. I take my car in on weekends to change the oil and replace the tires. Utilities do the same sort of thing when they have the opportunity to do so.

Q. WHAT IS YOUR CONCLUSION FROM THIS ANALYSIS?

A. The Commission should require modeling of a deferrable maintenance either by including it in off peak periods, or via weekend/weekday/HLH/LLH split of outage rates. Reverting back to the modeling that PacifiCorp used in GRID until UE 170 would be a very reasonable approach.

Q. HAVE OTHER REGULATORY COMMISSIONS ADDRESSED THIS QUESTION?

A. Yes. In Utah Docket No. 07-035-93, the Utah Commission considered the question of whether outage rates used in GRID should have a weekend/weekday split. As in UE 199, PacifiCorp changed its assumptions regarding the weekend/weekday split during the rebuttal phase of that case. The Utah Commission rejected PacifiCorp's proposal to eliminate the weekend/weekday split. Re PacifiCorp, Utah Public Service Commission, Docket No. 07-035-93, Final Order at 36-37 (August 11, 2008).

GENERATING UNIT REPRESENTATION IN GRID

Q. WHAT ISSUE DOES THIS SECTION OF YOUR TESTIMONY ADDRESS?

A. This section addresses the second part of Issue I.D on the Issue List regarding the question of "how should outage rates be properly applied within the power cost model?"

Q. EXPLAIN HOW GENERATOR OUTAGES ARE REPRESENTED IN GRID AND MONET.

A. Both models use what is known as the deration method to model outages. Outage rates are assumed to reduce the available capacity. This means that if a unit has 100 MW of capacity, and a 5% outage rate, the unit is represented in GRID and MONET as a 95 MW unit that is available 100% of the time. This is an industry standard technique. Though dated, this approach has been used in various models for many years. In effect, GRID replaces the capacity of each unit with its "expected value." The expected value, $MW_{e,}$ for a unit is computed as shown below:

MW_e = MW x (1-EFOR), where EFOR = the outage rate of the unit, and MW is the maximum capacity of the unit.

The above formula is appropriate because it represents a situation where the unit is fully available (i.e., to MW, the maximum capacity) (1-EFOR)[14/] percent of the time, and available at zero MW (because it is on an outage) EFOR[15/] percent of the time.

I have no objection to this representation, even though there are other, more sophisticated methods such as Monte Carlo modeling that may provide more realistic simulations. While it is not immediately obvious, proper use of the deration method also requires other adjustments to unit characteristics be made as well. First of all, the unit *minimum capacity,* MW(min) should also be derated in the same proportion as the *maximum capacity*. The expected value of the minimum capacity, $MW(min)_e$ is given by the formula below:

$MW(min)_e$ = MW(min) x (1-EFOR).

The simple and intuitive explanation is that unless this adjustment is made, the unit's *minimum* capacity could exceed its *maximum* capacity. This is where the modeling techniques employed by PGE and PacifiCorp differ substantially. In MONET, the adjustment discussed above is made within the model. In GRID, it is

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14/ 95% in the example above.
15/ 5% in the example above.

not, though it can be implemented with input adjustments already supplied with the model.

As a result, GRID could easily simulate situations where the maximum capacity is less than the minimum capacity. While this may seem far fetched, it actually has actually happened in GRID filed by PacifiCorp in its three most recently completed cases, in Oregon (UE 199), Utah and Wyoming. This illustrates a serious problem in the GRID model that has been avoided in MONET.

A more detailed and mathematical explanation is that when simulating operation at minimum loadings, it is also necessary to compute the expected value of the loading. If the unit is expected to be operating at minimum loading during a given hour, the expected value of its generation is MW(min) 1-EFOR percent of the time, and zero EFOR percent of the time. This is no different than the case discussed above involving maximum capacities. While the Company derates the maximum capacity for outages in GRID, it does not do so for the minimum capacity. Given the substantial number of resources now operating at minimum loading in GRID, this has become a very serious oversight.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE SHOWING WHY THIS ADJUSTMENT IS NECESSARY IN GRID?

A. Yes. Assume a hypothetical situation where a generator is dispatched at 10 MW for a 100 hour period. In this case, it would generate 1000 MWh. Now assume the unit was on forced outage half of that 100 hour period. In that case, it would only generate 500 MWh and have an outage rate of 50%.

If the unit has a maximum capacity of 10 MW, GRID's deration logic would treat it as a 5 MW unit running for all 100 hours. This is the way in which the derate model works. In that case, GRID would show it producing 500 MWh, and it would produce a result that matches with actual operation.

Now, however, assume that the unit really had a maximum capacity of 50 MW, but still had a minimum capacity of 10 MW and the same 50% outage rate. The same unit, dispatched at minimum for 100 hours, with a 50% outage rate would produce 500 MWh of energy. However, in this scenario, GRID would derate the maximum capacity to 25 MW - but it would still model a minimum capacity of 10 MW. This is because GRID would derate the maximum capacity for outages (50%) but would not do so for the minimum capacity. In this case, GRID would show the unit running at minimum capacity all 100 hours and still producing 1000 MWh, *or twice the correct amount*. Clearly, this problem must be fixed in GRID for results to be realistic. PGE clearly understood the nature of this problem, and addressed it in MONET.

Q. IS THIS THE ONLY ADJUSTMENT REQUIRED?

A. No. There must also be a corresponding issue concerning heat rates which is also addressed in MONET, but not in GRID. In GRID generating units are represented in GRID using a polynomial heat rate equation:

$$\textbf{Heat input (hour h)} = \mathbf{A+B \times MW_h + C \times MW_h^2}$$

This is a non-linear equation that expresses the amount of heat consumed by the generating unit as a function of the capacity level that the unit operates at. A, B, and C reflect coefficients that were originally determined in a curve fitting procedure that was used to create the heat rate equation based on actual data obtained from performing tests on the generating unit. Here MW_h is the loading of the unit in hour h.

If, for example, the unit is expected to be running at its maximum capacity, GRID's deration logic will multiply the unit's maximum capacity by its EFOR, as discussed above, and will treat it as a smaller unit running at less than full load. Returning to the original example of a 100 MW unit, GRID treats the 100 MW unit as a 95 MW unit for modeling purposes. Without a corresponding adjustment to the heat rate equation, the heat consumptions using the formula stated above will be incorrect, and will lead to an overstatement of the amount of heat consumed. The reason for this is that generating units are generally most efficient at their full loading point. Without an adjustment to the heat rate curve, GRID's deration logic will therefore overstate fuel costs.

This is again related to the concept of expected value. The proper calculation of the expected value of the heat consumption for the 100 MW unit is as follows:

Heat consumed = (A+B x 100 + C x 100^2) times 95% + 0 times 5%.

In effect, the above equation shows that the expected value of the heat consumed should be computed as (1-EFOR) times the heat input at full loading. GRID, however, would compute the heat input as shown below:

Heat consumed (GRID) = A+B x 95 + C x 95^2

While there appears to be only minor differences in the two formulas in the case when a unit is fully loaded, these small differences can add up. Further, because unit efficiencies typically decline as unit loadings decrease (moving down the heat rate curve), ignoring this adjustment will increase NPC. Even worse, not making this adjustment to the heat rate curve has produced absurd results in GRID studies.

While the above discussion concerns modeling of fully loaded units, a more important impact of this adjustment is for units running at minimum loading. In cases where GRID allows a unit to run with its maximum capacity below the minimum capacity, the heat rate can become absurdly high. This problem, however, is solved if these adjustments are applied.

Q. WHAT ADJUSTMENT TO THE HEAT RATE CURVE DO YOU RECOMMEND?

A. In this case, it is necessary to adjust the heat rate curve so that it produces the same heat consumption at the derated maximum and minimum capacities as the unit would actually experience in normal operation at the maximum and minimum ratings. The proper adjustment to the heat rate curve is as shown below:

Heat Rate Curve Adjusted = A x (1-EFOR)+B x MWh+ C/(1-EFOR) x $\mathbf{MW_h^2}$

Fortunately, PacifiCorp already supplies an input to GRID which makes this very adjustment. All one really needs to do is to supply GRID with this input for each resource.

Q. HAVE THESE MODELING TECHNIQUES BEEN APPLIED ELSEWHERE?

A. Yes, as noted. PGE applies these concepts in MONET. Further, in Utah Public Service Commission Docket No. 07-035-93, CCS witness Philip Hayet also testified that the method I am proposing is well accepted in the community of production cost modeling experts. Finally, I also applied these methods in a production simulation model that enjoyed substantial industry acceptance more than 25 years ago.

Ironically, PacifiCorp itself actually applies both of these techniques (adjusting minimum capacity and heat rate) to fractionally owned units such as Colstrip. From a modeling perspective, fractional ownership is the same thing as capacity deration. There is no reason why PacifiCorp should apply the technique for fractionally owned units, while ignoring them for units that are modeled as a fraction of their total capacity. If one thinks of forced outages as a “co-owner” of the resource, that has a call on its output 5 or 10% of the time it is easy to see why the modeling should, in fact, be the same as for fractionally owned units.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING THIS PROBLEM?

A. Yes. In its initial UE 199 GRID study, PacifiCorp modeled a monthly outage rate. For May 2009, PacifiCorp assumed an outage rate of 50% for Currant Creek. Applying that outage rate in GRID reduced the maximum capacity of the plant to around 210 MW. In the GRID modeling for May, PacifiCorp showed the unit running at 210 MW nearly all of the time. This is far less than the assumed minimum loading for the plant (340 MW), and resulted in an average heat rate for the unit in excess of 9,100 BTU/kWh for the month. This result clearly is far in excess of what would normally occur for the plant in conventional operation (which typically averages 7,300 BTU/kWh).

This problem stems from the unrealistic modeling of the unit with a large outage rate without making any corresponding adjustment to the minimum loading levels or the units heat rate curve. PacifiCorp would have exactly the same issue were it to model fractionally owned units without this adjustment. For this reason, PacifiCorp should make both the minimum loading and heat rate duration adjustments for all units which have non zero outage rates.

Q. HAVE YOU PREPARED AN ANALYSIS THAT TESTS THE REASONABLENESS OF THE GRID MODELING BASED ON ACTUAL DATA AND EVENTS?

A. Yes. I did several GRID simulations, focusing on May 2009, which assumed a 50% outage rate for Currant Creek. This was the Company's assumption in its initial UE 199 study because Currant Creek was off line most of May 2006 and on line nearly all of May 2007, the two years used by PacifiCorp to compute the Currant Creek outage rate in use in early 2008.

Q. HOW MIGHT ONE MODEL A SITUATION WHERE THE UNIT WAS OUT OF SERVICE HALF THE TIME, AS IT WAS DURING MAY OF 2007 AND MAY OF 2008?

A. There are three possible techniques that could be used in GRID. One could simply model a 50% outage rate, or take the unit out of service half the time during the period in question. Alternatively, one could model scenarios with Currant Creek available the entire month, and out of service the entire month, and average those results.

To test the reasonableness of the standard GRID technique, I modeled these alternatives. I did one scenario using the GRID standard logic, another with my proposed method, a scenario where Currant Creek was off line half the time in May 2009 (a logical way to represent a 50% outage rate) and scenarios with the plant on all month and off all month. The latter two scenarios were then averaged to result in a 50% availability case, again comparable to PacifiCorp's assumed outage rate.[16] If the GRID modeling is correct, the results from the GRID standard logic should be close to those obtained from the scenarios with Currant Creek out half the time, or based on the average of the fully on and fully off scenarios. However, the final results show GRID actually overstated the expected NPC (by $1.4-$1.7 million) and Currant Creek heat rates compared to the two logical alternative modeling methods and my proposed method. Further, the actual composite heat rate for Currant Creek for May 2006 and May 2007 was 7,310 BTU/kWh, which compares well with the result under all modeling methods (including mine) except the GRID's standard approach. As noted above, the GRID standard logic showed a heat rate for Currant Creek in excess of 9,100 BTU/kWh. I think this demonstrates that the GRID logic is faulty, as its predicted results are the outlier. Exhibit ICNU/111 shows the results of this analysis.

Q. PACIFICORP STOPPED USING MONTHLY OUTAGE RATES IN ITS JULY FILING IN UE 199. HAS PACIFICORP SOLVED THIS PROBLEM BY ELIMINATING THE MONTHLY OUTAGE RATES?

A. No. The problem remains. It is simply *less obvious* because the extremely high May outage rate is now blended in with all the other months. This means that instead of May showing an obviously overstated heat rate in GRID, the heat rate for each individual month is overstated by a less noticeable amount.

Q. HAS PACIFICORP DISCUSSED THIS ISSUE IN ITS RECENT TESTIMONY?

A. Yes. Mr. Duvall continues to argue that no adjustment is needed. Mr. Duvall has made a number of arguments concerning this issue. Mr. Duvall has made three basic points: 1) derating the minimum capacity would allow the model to simulate

[16] Note that there were very few derations during May 2006 and 2007, and deration events are uncommon for combined cycle plants in general.

operation below its actual minimum, which he says the units can never achieve, and Duvall warns this will produce unrealistic results; 2) the adjustment I propose does not work properly because it ignores partial outages which result in units being derated but not completely out of service; and 3) comparison of <u>actual</u> heat rates to GRID heat rates for coal plants shows that no further adjustment is needed.

Q. HOW DO YOU RESPOND TO MR. DUVALL'S FIRST ARGUMENT?

A. First, GRID already allows a unit to run at a level below its minimum capacity rating, as was shown in the example of Currant Creek above. As long as the outage rate is high enough, GRID will allow units to run below its rated minimum capacity. Mr. Duvall does not seem to view this as a problem, and has proposed no correction for it.[17]

Second, Mr. Duvall objects to derating the minimum because it allows the model to let a unit run at a level it can never achieve. However, GRID already derates the maximum capacity even though that prevents the unit from *ever* running at a capacity it actually *can achieve*. If derating the minimum is unrealistic, then derating the maximum is as well.

Third, Mr. Duvall explicitly adopts the concept of "expected value" when GRID reduces the *maximum* capacity of resources below their physical limits, but would have the model ignore it for the equally valid issue of applying the minimum capacity. Either the model is correct in using the concept of expected value of capacity, or it isn't. If it is (and most experts believe it is), then unit minimum capacities should be derated just the same as the unit maximum capacity.

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[17] Correcting this problem would decrease NPC, as it would be equivalent to placing a limit on outage rates.

Q. DOES MR. DUVALL HAVE A POINT CONCERNING PARTIAL OUTAGES?

A. Yes. I agree that it is more proper to recognize that when partial outages occur, they are less likely to impact the minimum loading of a unit. As a result, I recommend removed of partial outages in performing the adjustments.

Q. PLEASE DISCUSS MR. DUVALL'S ARGUMENT CONCERNING THE COMPARISONS TO ACTUAL HEAT RATES FOR COAL PLANTS.

A. Mr. Duvall made these arguments in the current Utah GRC. There are three important points. First, Mr. Duvall's figures show the minimum loading and heat rate adjustment has very little impact on coal plants. In fact, the overall change to heat rates is far less than one half of one percent. At best, Mr. Duvall's limited data demonstrate that this issue is a "toss up" for coal units. However, noticeably *absent* from Mr. Duvall's heat rate comparison were the PacifiCorp's gas units.[18/] GRID consistently overpredicts the heat rates of gas units, and the minimum loading and heat rate adjustment really *enhances, rather than diminishes,* the overall accuracy of heat rates results simulated in GRID. Finally, my current method has been refined to more properly recognize partial outages.

The table below shows a comparison of the GRID simulation results and actual heat rates with and without this proposed adjustment. As the table shows, the GRID modeling method is not accurate when applied to gas units, which cycle more often. The table shows that as there is really little basis for choosing between the two methods based on comparison to actual heat rates for coal plants. However, when gas units are included, the method produces more realistic results

18/ Considering that Mr. Duvall himself testified in UE 199 that the impact on coal plants is minor because they are us normally "in the money", it's puzzling that he would focus on coal plants for his analysis.

than the methodology embedded in GRID. Overall, the use of the derate adjustments improves the system average heat rate results as compared to the current method modeled in GRID. I recommend the Commission adopt this modeling method and require PacifiCorp to begin using it in its power cost studies. PGE already addresses these problems in MONET, and PacifiCorp already models fractionally owned units in the manner I propose.

Table 3 – Comparison of Actual to GRID Heat Rates (BTU/kWh)

	Actual Data	Company Method	Derate Method
Coal Average	10,700	10,712	10,688
Coal Weighted	10,609	10,619	10,595
Gas Average	9,063	9,541	9,493
Gas Weigthed	7,387	7,509	7,461
Coal + Gas Avg.	9,882	10,126	10,091
Coal + Gas Wtd.	10,048	10,077	10,050

Q. WHAT REPORTING REQUIREMENTS SHOULD THE COMMISSION THE REQUIRE FOR OUTAGE DATA?

A. The Commission should require data comparable to that provided by PacifiCorp in ICNU DRs 1.6-1 and 1.6-2, in UE 199 for all thermal, hydro and wind resources. A sample of this data is provided in Exhibit ICNU/106. This is standard information nearly all utilities report to the NERC on a routine basis. I recommend that this data be required concurrent with all filings made by either PGE or PacifiCorp in general rate case, TAM, or AUT cases. Further, both PGE and PacifiCorp should be required to file, concurrent with these filings, copies of all Root Cause Analyses, for all outages that last longer than 1 week. This will enable parties to review the prudence of all long outages that have occurred within the historic period. Also, data necessary to compute the $EFOR_d$ statistics should be provided as well. Further, both companies should be required to file data showing the trend in availabilities for their units by fuel type. Annual equivalent forced outage rates and equivalent availability factors should be provided for each year in the multi-year period. Finally, these data should be considered as public because there is little basis for believing that revealing outage events that occurred months, or years in the past should be considered confidential information.

Note, however, that PGE may not be collecting this information. If so, then PGE should be required to do so.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-	NC	NC Industrial	Duke Power Co.	Incentive fuel adjustment

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	Sub 408		Energy Committee		clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico	Imprudence disallowance.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
				Utility Counsel	Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT	CCS	PacifiCorp	Certification of Peaking Plant
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

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

In accordance with the schedule in this proceeding, the Oregon Public Utility Commission Staff, on behalf of the UM 1355 parties, respectfully submits this consolidated issues list.

UM 1335 Consolidated Issues List

I. What forecasting methodology should the Commission adopt for thermal generating plants?

   A. Should there be a different forecasting method for peaker plant versus base load plant?

      1. Are there any particular considerations (e.g. combined cycle plant outage rate computations)?

   B. Which forced outages should be included in the forced outage rate determination (e.g. extreme events)?

      1. What role should industry data play in this determination?

   C. What methodology should be employed for treatment of excluded outages?

   D. What is the appropriate methodology for calculating forced outage rates and how should that be applied within the power cost model?

   E. How should new thermal resources be treated?

   F. What is the appropriate length for the historical period?

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G. Should non-outage related adjustments be included in the forced outage rate determination? If so, which non-outage related adjustments should be included?

H. Should the forced outage rate determination be adjusted when a new capital investment improves reliability?

II. What hydro availability methodology should the Commission adopt?

III. What wind availability reporting method should the Commission adopt?

A. How should wind availability be appropriately applied to forecasting for a rate determination?

IV. What methodology should the Commission adopt for planned maintenance (e.g. average versus forecast) of thermal, hydro, and wind plants?

A. How should this methodology be applied (e.g. high load/low load split, weekend/weekday split)?

V. What data reporting requirements should the Commission require regarding outages?

DATED this 30th day of January 2009.

Respectfully submitted,

HARDY MYERS
Attorney General

Jason W. Jones, #00059
Assistant Attorney General
Of Attorneys for Public Utility Commission of Oregon

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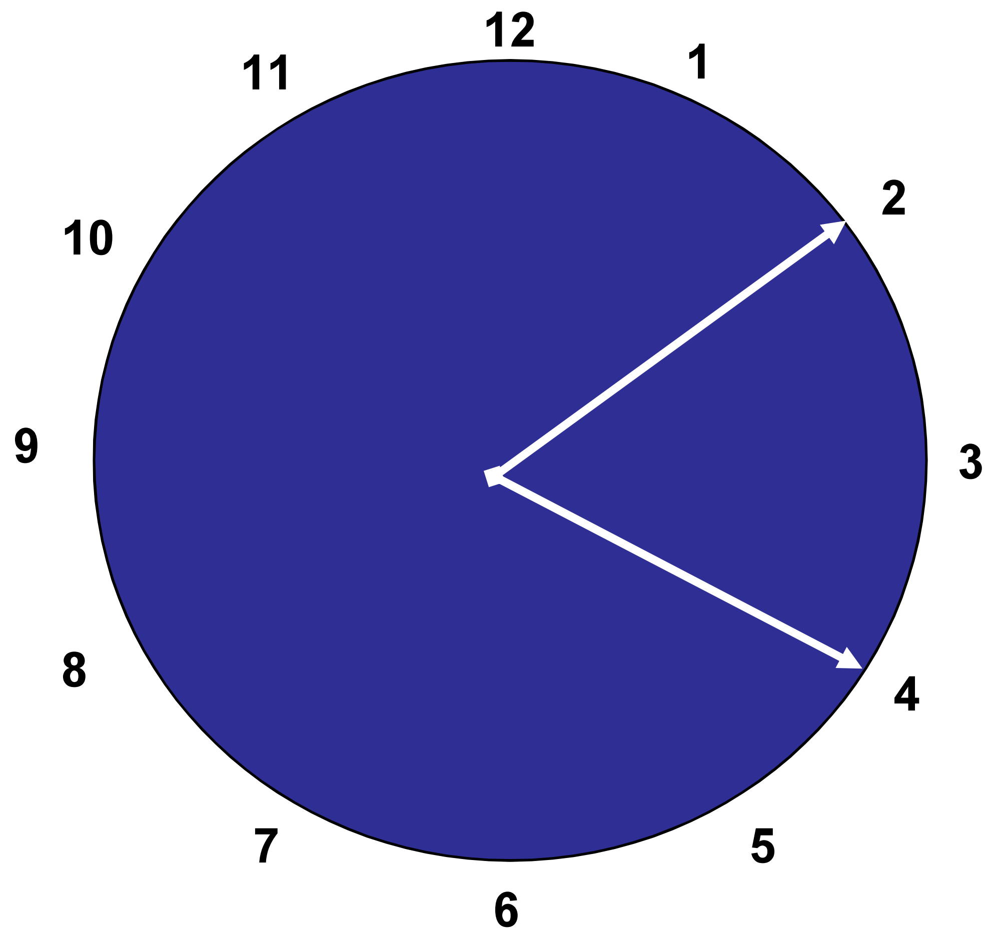
Equiv. Forced Outage Rate – Demand (EFORd)

- Markov equation developed in 1970's
- Used by the industry for many years
  - PJM Interconnection (20 years)
  - Similar to that used by the Canadian Electricity Association (20 years)
  - Being use by the CEA, PJM, New York ISO, ISO New England, and California ISO

Equiv. Forced Outage Rate – Demand (EFORd)

- Interpretation:
  - The probability that a unit will not meet its *demand periods* for generating requirements.
  - Best measure of reliability for all loading types (base, cycling, peaking, etc.)
  - Best measure of reliability for all unit types (fossil, nuclear, gas turbines, diesels, etc.)
  - For demand period measures and not for the full 24-hour clock

Equiv. Forced Outage Rate – Demand (EFORd)



EFORdEquation:

$$\text{EFORd} = \frac{[(\text{FOHd}) + (\text{EFDHd})]}{[\text{SH} + (\text{FOHd})]} \times 100\%$$

Where: FOHd = f x FOH

$$f = \frac{[(1/r)+(1/T)]}{[(1/r)+(1/T)+(1/D)]}$$

r= FOH/(# of FOH occur.)

T= RSH/(# of attempted Starts)

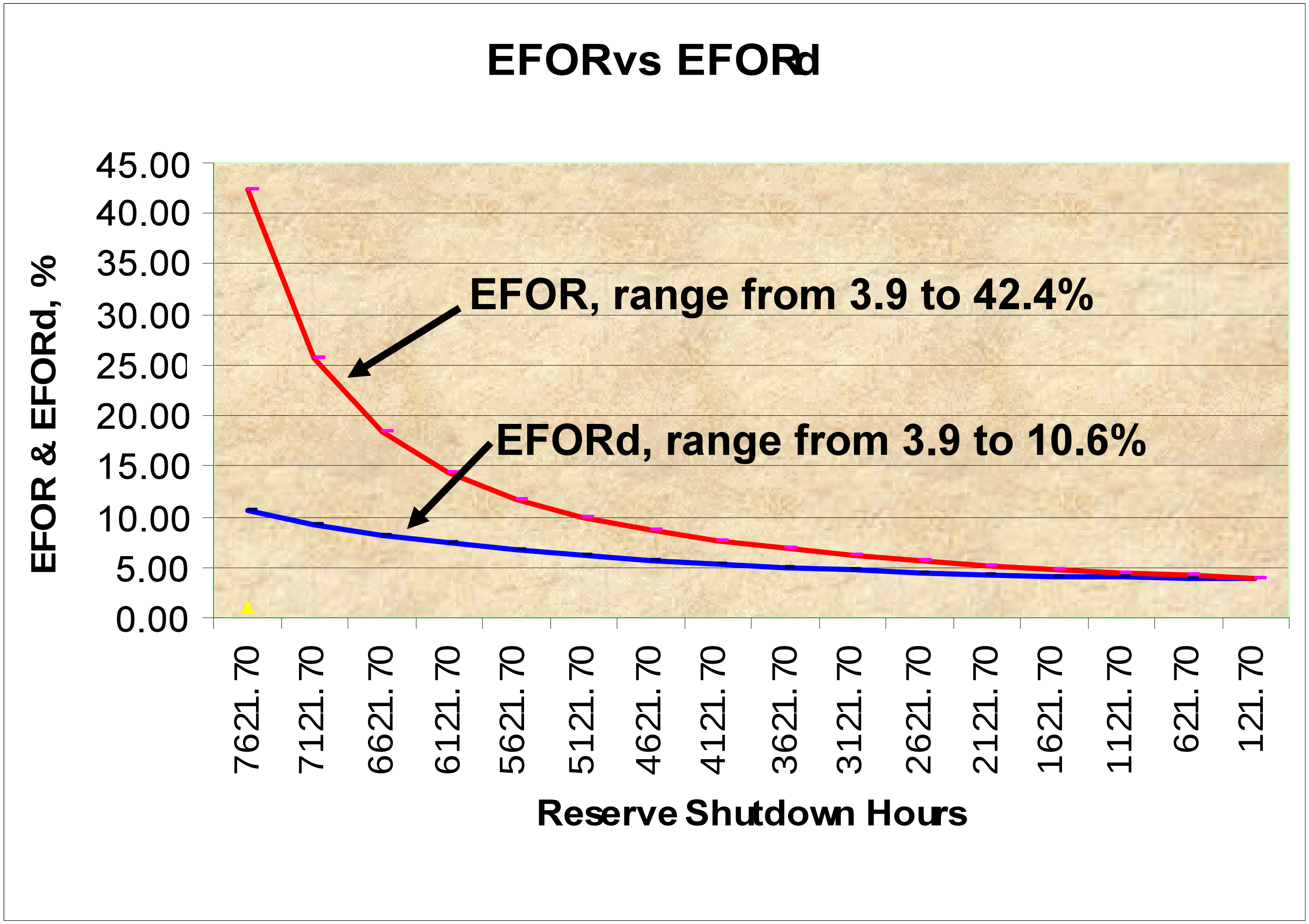
D= SH/(# of actual starts)

EFDHd = fp x EFDH

fp = SH/AH

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Exampleof EFORd



ICNU/105
Example Combined Cycle EFOR Calculation

Currant Creek Analysis	Mw		WD	WE	
CT1 (Cur 1)		141	5.00%	6.00%	
CT2 (Cur 2)		141	5.00%	6.00%	
SG (Cur 3)		141	4.00%	5.00%	
DF		105	4.00%	5.00%	
Avaialability					
CT1 (Cur 1)		141	95.00%	94.00%	
CT2 (Cur 2)		141	95.00%	94.00%	
SG (Cur 3)		141	96.00%	95.00%	
DF		105	96.00%	95.00%	
Derated Capacity	CC1+CC2+SG		404	400	
	EFOR		4.67%	5.67%	4.95%
	CC1+CC2+SG+DF		505	499	
	EFOR		4.53%	5.53%	

EXHIBIT ICNU 106 - Event Backup
48 Months ended December 2007

Unit ID	Event Type	Beg Date/Time	End Date/Time	DP Code	Avail. MW	Actual Hrs. Duration	Actual Lost MWH	NERC Code	Standardized NERC Description	Plant Narrative
BLN-1	Forced Derating	01/06/2004 12:20	01/09/2004 12:03		20	71.717	215.15	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	I.G. having problems with well 28-3 seperator level probes. High high alarm coming in and tripping our brine pump.
BLN-1	Forced Derating	01/30/2004 12:36	01/30/2004 14:36		18	2	10	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	G had level probe problem on 54-3 well; which dumped separator and tripped BR-1A. The upset caused 13-10 well to dump
BLN-1	Forced Derating	01/31/2004 09:00	01/31/2004 09:45		17	0.75	4.5	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG had to bring 54-3 well down to do a repair. In the process we lost 13-10 also.
BLN-1	Forced Derating	01/31/2004 09:45	01/31/2004 12:50		19	3.083	12.333	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	54-3 well had to be taken down for repairs.
BLN-1	Forced Derating	02/07/2004 13:24	02/07/2004 14:00		18	0.6	3	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG had separator problems at 54-3 well.
BLN-1	Maint. Outage	02/17/2004 07:45	02/17/2004 20:24		0	12.65	290.95	4200	LP OUTER CASING	TURBIINE DRAIN LEAKING STEAM
BLN-1	Maint. Derating	02/17/2004 20:24	02/18/2004 19:00		20	22.6	67.8	6420	CONDENSATE REINJECTION SYSTEM	Br-6 Flush Line is leaking and needs to be repaired. Br-6 off line.
BLN-1	Forced Derating	02/25/2004 03:35	02/25/2004 06:30		15	2.917	23.333	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	45-3 MICON PROBLEM TRIPPED BR-5A AND BR-6
BLN-1	Maint. Outage	02/27/2004 09:18	02/27/2004 19:37		0	10.317	237.283	6499	GEOTHERMAL MISCELLANEOUS	Steam leak on the knockout drum drain line has to be repaired.
BLN-1	Forced Derating	03/18/2004 19:30	03/27/2004 08:00		20	151.45	454.35	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 Micon died. Well had to be taken down.
BLN-1	Maint. Outage	03/23/2004 05:17	03/25/2004 02:53		0	45.6	1048.8	6499	GEOTHERMAL MISCELLANEOUS	Checking out CO-1b condensate pump problem Fixing T1-transformer leak.
BLN-1	Forced Derating	03/25/2004 02:53	03/25/2004 10:20		13	7.45	74.5	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG&C working on it.
BLN-1	Forced Derating	03/27/2004 08:00	03/27/2004 09:00		21	1	2	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 Micon died. Well had to be taken down.
BLN-1	Forced Derating	03/27/2004 09:00	03/29/2004 07:00		21	46	92	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 Micon died. Well had to be taken down.
BLN-1	Forced Derating	03/29/2004 07:00	03/29/2004 08:00		21	1	2	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 Micon died. Well had to be taken down.
BLN-1	Forced Derating	03/29/2004 08:00	03/29/2004 21:00		20	13	39	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 Micon died. Well had to be taken down.
BLN-1	Forced Derating	04/01/2004 21:19	04/02/2004 10:20		21	13.017	26.033	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	1310 Well is Out of Service. IG Steam supplier is having problems with their Micon.
BLN-1	Forced Derating	04/04/2004 21:00	04/04/2004 22:55		19	1.917	7.667	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	54-3 well high high level probe said it was in shut in well. There was a wire broke they fix it.
BLN-1	Reserve Shutdown	04/22/2004 12:05	04/22/2004 13:15		23	1.167	0	0000	RESERVE SHUTDOWN	Reserve Shutdown - Transmission line down because of snow and rain.
BLN-1	Forced Outage	05/12/2004 18:00	05/13/2004 10:00		0	16	368	4609	OTHER EXCITER PROBLEMS	Jnit trips when field brkr is put in and exciter has a DC charge placed on it. Found the exciter relay #41 tripped behind the c
BLN-1	Forced Outage	05/13/2004 14:52	05/13/2004 21:39		0	6.783	156.017	4499	OTHER MISCELLANEOUS STEAM TURBINE PROBLI	52-G1 opened up on us; and we can't get the turbine to reset. No obvious flags on any relays.
BLN-1	Forced Derating	05/13/2004 21:39	05/14/2004 02:00		14	4.35	39.15	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 well is out of service and other wells have low wellhead pressures.
BLN-1	Forced Derating	05/14/2004 02:00	05/14/2004 07:00		16	5	35	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 well is out of service and other wells have low wellhead pressures.
BLN-1	Forced Derating	05/14/2004 07:00	05/14/2004 11:00		17	4	24	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 well is out of service and other wells have low wellhead pressures.
BLN-1	Forced Derating	05/14/2004 11:00	05/14/2004 12:00		18	1	5	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 well is out of service and other wells have low wellhead pressures.
BLN-1	Forced Derating	05/14/2004 12:00	05/14/2004 14:39		21	2.65	5.3	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	13-10 well is out of service and other wells have low wellhead pressures.
BLN-1	Forced Derating	05/31/2004 06:15	05/31/2004 07:22		15	1.117	8.933	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	28-3 well tripped which then caused 13-10 to trip. IG could not find the reason the well tripped.
BLN-1	Forced Derating	06/02/2004 06:08	06/02/2004 07:00		15	0.867	6.933	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	INTERMOUNTAIN WELL 28-3 SHUT IN FOR SOME REASON WHICH TOOK 13-10 WELL OFF LINE
BLN-1	Forced Derating	06/02/2004 07:00	06/02/2004 08:00		17	1	6	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	INTERMOUNTAIN WELL 28-3 SHUT IN FOR SOME REASON WHICH TOOK 13-10 WELL OFF LINE
BLN-1	Forced Derating	06/28/2004 13:00	06/28/2004 16:26		21	3.433	6.867	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	I & G level probe problem
BLN-1	Forced Outage	06/28/2004 16:26	06/28/2004 20:00		0	3.567	82.033	9020	LIGHTNING	lighting triped line from milford to plant
BLN-1	Forced Outage	06/28/2004 20:00	06/28/2004 22:23		0	2.383	54.817	4307	AUTOMATIC TURBINE CONTROL SYSTEMS - ELEC	problems with trubine control valve.
BLN-1	Forced Derating	07/01/2004 19:36	07/01/2004 21:24		13	1.8	18	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	.G. is having well problems. They lost 45-3 well and then becuase of line disturbances; they lost the production at 13-10 we
BLN-1	Forced Outage	07/02/2004 08:30	07/02/2004 09:43		0	1.217	27.983	3684	HIGHER THAN 12KV PROTECTION DEVICES	CAMERON SUBSTATION OPENED UP; WHICH OPENED OCB-21 3 Voltage regulators apparently blew up today causing
BLN-1	Forced Outage	07/08/2004 17:47	07/08/2004 18:00		0	0.217	4.983	3684	HIGHER THAN 12KV PROTECTION DEVICES	Lines and Services were working on the new breaker scheme at the Cameron Sub. and they tripped us off line.
BLN-1	Maint. Derating	07/17/2004 00:30	07/17/2004 02:15		19	1.75	7	4611	HYDROGEN COOLERS	Cleaned H2 Coolers
BLN-1	Maint. Derating	07/28/2004 10:45	07/30/2004 15:08		16	52.383	366.683	6420	CONDENSATE REINJECTION SYSTEM	SWITCHING BRINE PUMP AT WELL SITE 45-3 SWITCHING FROM BR5A TO BR5 PUMP
BLN-1	Forced Derating	09/05/2004 17:20	09/06/2004 13:25		21	20.083	40.167	6420	CONDENSATE REINJECTION SYSTEM	Br-6 Flush Pumps won't run. Had to shut in 13-10 Well. Shut off Br-6 Brine Pump.
BLN-1	Reserve Shutdown	09/09/2004 13:55	09/09/2004 14:43		23	0.8	0	0000	RESERVE SHUTDOWN	cameron substation open up ;lighing
BLN-1	Forced Outage	09/14/2004 14:15	09/14/2004 14:50		0	0.583	13.417	6499	GEOTHERMAL MISCELLANEOUS	Ne are not totally sure why our CB52-G1Brkr opened and tripped us off line. Devoge electricians were working on some wir
BLN-1	Planned Outage	09/19/2004 00:22	09/24/2004 01:50		0	121.467	2793.733	3600	SWITCHYARD TRANSFORMERS AND ASSOCIATED	working on t/1 transformer. and other shutdown items
BLN-1	Forced Derating	09/24/2004 02:00	09/24/2004 23:00		13	21	210	6420	CONDENSATE REINJECTION SYSTEM	Our reinjection pump BR-3 has a seal leak; and our alternate pump is in the shop getting repaired; we expect it back Monda
BLN-1	Forced Derating	09/24/2004 23:00	09/25/2004 00:00		14	1	9	6420	CONDENSATE REINJECTION SYSTEM	Our reinjection pump BR-3 has a seal leak; and our alternate pump is in the shop getting repaired; we expect it back Monda
BLN-1	Forced Derating	09/25/2004 00:00	09/28/2004 17:35		13	89.583	895.833	6420	CONDENSATE REINJECTION SYSTEM	Our reinjection pump BR-3 has a seal leak; and our alternate pump is in the shop getting repaired; we expect it back Monda
BLN-1	Forced Derating	10/06/2004 13:32	10/07/2004 01:00		18	11.467	57.333	6420	CONDENSATE REINJECTION SYSTEM	Replace BR-4 Suction & Discharge Valves.
BLN-1	Forced Derating	10/07/2004 01:00	10/07/2004 08:12		18	7.2	36	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG was having trouble bringing up their 28-3 well
BLN-1	Forced Derating	10/08/2004 14:38	10/08/2004 16:24		18	1.767	8.833	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	.G. lost control of their 45-3 well. The micon controller went south on them and started dumping their well without sounding
BLN-1	Forced Derating	10/20/2004 22:10	10/21/2004 00:00		19	1.833	7.333	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	.G. lost another MIcon card that controlls their wells. This time it was 54-3; they don't think they have another card to replac
BLN-1	Forced Derating	11/09/2004 06:15	11/09/2004 16:25		21.5	10.167	15.25	6420	CONDENSATE REINJECTION SYSTEM	PLC problems at BR-6 caused flush tank valve not to open; tank went dry; flush pump didn't have water to pump; so we thin
BLN-1	Forced Derating	11/14/2004 03:54	11/14/2004 04:45		14	0.85	7.65	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG lost 45-3 Well due to one of their 110 supply breakers tripping.
BLN-1	Forced Derating	11/14/2004 05:52	11/14/2004 11:00		16	5.133	35.933	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	Lost 45-3 Steam Well. 110 breaker tripped.
BLN-1	Maint. Outage	11/16/2004 05:39	11/16/2004 19:34		0	13.917	320.083	4261	CONTROL VALVES	changing out main control valve actuator
BLN-1	Forced Derating	11/20/2004 22:40	11/21/2004 00:00		17	1.333	8	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	.G. lost control of their 45-3 well dump valve. It opened and wouldn't close. We had to shut down the brine transfer pump #I
BLN-1	Forced Outage	11/29/2004 06:53	11/29/2004 09:11		0	2.3	52.9	3132	INTER AND AFTER CONDENSERS	ntercondenser transmitter froze. Valve went closed thinking level was low. Then intercondenser overflowed water into the e
BLN-1	Forced Derating	12/14/2004 02:00	01/01/2005 00:00		18	420.9	2104.5	6420	CONDENSATE REINJECTION SYSTEM	problems with pump
BLN-1	Forced Outage	12/14/2004 06:51	12/14/2004 13:52		0	7.017	161.383	4299	TURBINE OTHER HYDRAULIC CONTROL SYSTEM P	A solenoid on the EHC system failed when we did a stop valve test. It closed the stop valve which tripped the unit; and then
BLN-1	Forced Derating	12/15/2004 11:21	12/15/2004 13:26		13	2.083	20.833	3669	OTHER 4160-VOLT PROBLEMS	
BLN-1	Forced Derating	01/01/2005 00:00	01/02/2005 08:00		20	32	96	6420	CONDENSATE REINJECTION SYSTEM	problems with pump
BLN-1	Forced Derating	01/02/2005 08:00	02/11/2005 01:41		19	908.367	3633.467	6420	CONDENSATE REINJECTION SYSTEM	problems with pump
BLN-1	Forced Derating	01/07/2005 09:19	01/07/2005 11:58		14	2.65	23.85	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	IG's inlet valve at 54-3 froze up and we had to shut down our pump
BLN-1	Forced Outage	01/13/2005 10:18	01/13/2005 12:32		0	2.233	51.367	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	Unit trip IG sent slug of water/ safety valve problem..
BLN-1	Forced Outage	01/13/2005 13:32	01/13/2005 15:30		0	1.967	45.233	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	28-3 Well Dumped / Unit Trip
BLN-1	Forced Derating	01/13/2005 15:30	01/13/2005 20:30		9	5	70	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	28-3 Steam Well is down / Waiting to get some parts to Repair. Parts repaired; now waiting on 45-3 problems. Finished repa
BLN-1	Forced Derating	01/13/2005 20:31	01/14/2005 12:46		9	16.25	227.5	6420	CONDENSATE REINJECTION SYSTEM	Our Brine transfer pump BR-5 wouldn't start and run; possible pump rotor siezure; or brkr trouble.
BLN-1	Forced Derating	01/25/2005 11:45	01/25/2005 20:00		14	8.25	74.25	6420	CONDENSATE REINJECTION SYSTEM	BR-4A Brine Pump Motor Fan came apart and needs to be repaired.
BLN-1	Forced Derating	01/28/2005 18:09	01/28/2005 19:45		14	1.6	14.4	6420	CONDENSATE REINJECTION SYSTEM	plug in crane to br4's 1/10 out let and it over load the out let and trip WELL.
BLN-1	Forced Derating	02/03/2005 09:35	02/03/2005 11:00		13	1.417	14.167	6410	STEAM WELLS/STEAM FIELD PIPING PROBLEMS	.G. lost control of their inlet control valve at 54-3 well; it slammed shut on them and the only way to repair it was off line. It t

[redacted]

Exhibit ICNU/108
Maintenance Outage and Derations Hours
Four Years Ended June 2008

Event Type	(All)							
						Disproportionate		
				% Coal	76.9%	92.3%	Coal
	Data			%	64.1%	82.1%	All Units
Unit ID	Sum of Adj HLH	Sum of Adj LLH	HLH	LLH	LLH>HLH	LLH>43.96%	Coal
BLN-1	568	407	568	407	0	0	
BLN-2	216	148	216	148	0	0	
CHO-4	18	49	18	49	1	1	Coal
COL-3	167	227	167	227	1	1	Coal
COL-4	226	309	226	309	1	1	Coal
CRB-1	85	134	85	134	1	1	Coal
CRB-2	173	236	173	236	1	1	Coal
CRG-1	1	1	1	1	0	1	Coal
CRG-2	20	40	20	40	1	1	Coal
CUR-1	86	105	86	105	1	1	
CUR-2	174	177	174	177	1	1	
CUR-3	174	173	174	173	0	1	
DJ-1	7	0	7	0	0	0	Coal
DJ-2	52	85	52	85	1	1	Coal
DJ-3	5	20	5	20	1	1	Coal
DJ-4	385	380	385	380	0	1	Coal
GAD-3	130	123	130	123	0	1	
GAD-4	4	0	4	0	0	0	
GAD-5	45	64	45	64	1	1	
HDN-1	340	243	340	243	0	0	Coal
HDN-2	215	178	215	178	0	1	Coal
HRM-1	104	119	104	119	1	1	
HRM-2	106	85	106	85	0	1	
HTG-1	278	340	278	340	1	1	Coal
HTG-2	312	385	312	385	1	1	Coal
HTR-1	764	791	764	791	1	1	Coal
HTR-2	1,146	1,293	1,146	1,293	1	1	Coal
HTR-3	937	1,116	937	1,116	1	1	Coal
JB-1	349	421	349	421	1	1	Coal
JB-2	213	487	213	487	1	1	Coal
JB-3	309	537	309	537	1	1	Coal
JB-4	140	249	140	249	1	1	Coal
LMT-1	11	0	11	0	0	0	
LS-2	34	47	34	47	1	1	
LS-3	2	0	2	0	0	0	
NTN-1	501	887	501	887	1	1	Coal
NTN-2	326	647	326	647	1	1	Coal
NTN-3	660	924	660	924	1	1	Coal
WV-3	1	0	1	0			
WV-4	3	0	3	0			
WV-5	1	0	1	0			
WYO-1	536	446	536	446	0	1	Coal
Grand Total	9,824	11,873	9,824	11,873	1	1	

All Units	HLH	LLH
% of Hours (Outages)	45.28%	54.72%
% of all hours	56.04%	43.96%
	HLH	LLH
Coal Units	8165	10426
	43.9%	56.1%

Exhibit ICNU/109
Maintenance Outage and Derations Hours
Four Years Ended June 2008

Event Type	(All)					
			% Coal		80.8%	Coal
	Data		%		73.8%	All Units
					Disproportionate	
Unit ID	Sum of Adj WD	Sum of Adj WE	WD	WE	WE>28.6%	Coal
BLN-1	711	263	711	263	0	
BLN-2	248	116	248	116	1	
CHO-4	33	34	33	34	1	Coal
COL-3	104	290	104	290	1	Coal
COL-4	168	367	168	367	1	Coal
CRB-1	126	93	126	93	1	Coal
CRB-2	206	204	206	204	1	Coal
CRG-1	2	0	2	0	0	Coal
CRG-2	12	48	12	48	1	Coal
CUR-1	80	110	80	110	1	
CUR-2	193	158	193	158	1	
CUR-3	170	177	170	177	1	
DJ-1	7	0	7	0	0	Coal
DJ-2	42	95	42	95	1	Coal
DJ-3	21	4	21	4	0	Coal
DJ-4	452	312	452	312	1	Coal
GAD-3	79	174	79	174	1	
GAD-4	4	0	4	0	0	
GAD-5	69	40	69	40	1	
HDN-1	430	152	430	152	0	Coal
HDN-2	231	163	231	163	1	Coal
HRM-1	104	119	104	119	1	
HRM-2	106	85	106	85	1	
HTG-1	362	255	362	255	1	Coal
HTG-2	384	313	384	313	1	Coal
HTR-1	922	633	922	633	1	Coal
HTR-2	1,336	1,103	1,336	1,103	1	Coal
HTR-3	1,132	921	1,132	921	1	Coal
JB-1	545	225	545	225	1	Coal
JB-2	429	271	429	271	1	Coal
JB-3	531	314	531	314	1	Coal
JB-4	284	106	284	106	0	Coal
LMT-1	11	0	11	0	0	
LS-2	31	50	31	50	1	
LS-3	0	2	0	2	1	
NTN-1	888	499	888	499	1	Coal
NTN-2	664	308	664	308	1	Coal
NTN-3	774	810	774	810	1	Coal
WV-3	1	0	1	0	0	
WV-4	3	0	3	0	0	
WV-5	1	0	1	0	0	
WYO-1	522	459	522	459	1	Coal
Grand Total	12,422	9,275	12,422	9,275	1	

All Units	WD	WE
% of Hours (Outages)	57.25%	42.75%
% of all hours	71.39%	28.61%
	WD	WE
Coal Units	10610	7981
	57.1%	42.9%

Exhibit ICNU/110
Comparison of Weekend and Weekday Outage Rates
Data for 48 Months Ended Dec. 2007

WeekDay				Weekend				Difference	
WD	Lost Energy	Schedule	EFOR	WE	Lost	Schedule	EFOR	WE-WD	WE>WD
BLN-1	27879.574	550178.4	5.07%	BLN-1	9721.266	220592.2	4.41%	-0.66%	0
CHO-4	747626.723	9251119	8.08%	CHO-4	373673.7	3701371	10.10%	2.01%	1
COL-3	1399959.335	17213843	8.13%	COL-3	704545.5	6889141	10.23%	2.09%	1
COL-4	1329796.599	17889389	7.43%	COL-4	706037	7139520	9.89%	2.46%	1
CRB-1	145008.152	1612728	8.99%	CRB-1	57849.48	641622.3	9.02%	0.02%	1
CRB-2	162303.318	2537106	6.40%	CRB-2	92149.02	1014881	9.08%	2.68%	1
CRG-1	660626.518	10713696	6.17%	CRG-1	322872.9	4293696	7.52%	1.35%	1
CRG-2	430048.183	10219599	4.21%	CRG-2	218498.1	4085310	5.35%	1.14%	1
DJ-1	155468.823	2633420	5.90%	DJ-1	64450.83	1053387	6.12%	0.21%	1
DJ-2	136741.202	2545180	5.37%	DJ-2	56308.3	1017349	5.53%	0.16%	1
DJ-3	415597.95	5366064	7.74%	DJ-3	218462	2144421	10.19%	2.44%	1
DJ-4	900192.666	8141183	11.06%	DJ-4	475540.1	3257617	14.60%	3.54%	1
GAD-1	2383	141743.2	1.68%	GAD-1	1124	52267.74	2.15%	0.47%	1
GAD-2	20417.833	262638	7.77%	GAD-2	15864.83	106563.8	14.89%	7.11%	1
GAD-3	32710.333	462187.4	7.08%	GAD-3	25796.67	160270.1	16.10%	9.02%	1
GAD-4	6622.83	394650	1.68%	GAD-4	2928.798	139501.1	2.10%	0.42%	1
GAD-5	12634.5	378958.3	3.33%	GAD-5	4782.797	131615.4	3.63%	0.30%	1
GAD-6	16501.5	357670.4	4.61%	GAD-6	6665.466	126353.3	5.28%	0.66%	1
HDN-1	241242.935	4495488	5.37%	HDN-1	92760.77	1797738	5.16%	-0.21%	0
HDN-2	240250.368	6390586	3.76%	HDN-2	95225.25	2543649	3.74%	-0.02%	0
HRM-1	64558.334	5479624	1.18%	HRM-1	88443.53	2140270	4.13%	2.95%	1
HRM-2	174686.231	5410251	3.23%	HRM-2	88067.35	2110307	4.17%	0.94%	1
HTG-1	1157921.716	10793920	10.73%	HTG-1	587065.4	4306087	13.63%	2.91%	1
HTG-2	1140473.23	10777650	10.58%	HTG-2	498193.1	4308578	11.56%	0.98%	1
HTR-1	1033905.881	10533259	9.82%	HTR-1	468268.8	4210560	11.12%	1.31%	1
HTR-2	818301.179	10505165	7.79%	HTR-2	452134.6	4191189	10.79%	3.00%	1
HTR-3	1218690.114	11095499	10.98%	HTR-3	537785.7	4416084	12.18%	1.19%	1
JB-1	1494775.519	12820691	11.66%	JB-1	611071.8	5104041	11.97%	0.31%	1
JB-2	1669211.304	12663343	13.18%	JB-2	711178.5	5032094	14.13%	0.95%	1
JB-3	1620441.732	12618134	12.84%	JB-3	771061.8	5054045	15.26%	2.41%	1
JB-4	1743499.487	12772391	13.65%	JB-4	814164.8	5113705	15.92%	2.27%	1
LMT-1	1213.933	295123.5	0.41%	LMT-1	491.434	118775.8	0.41%	0.00%	1
NTN-1	377778.249	3885733	9.72%	NTN-1	164072.7	1551563	10.57%	0.85%	1
NTN-2	369690.768	5043210	7.33%	NTN-2	172346.2	2014733	8.55%	1.22%	1
NTN-3	777041.285	8206968	9.47%	NTN-3	375323.3	3279359	11.45%	1.98%	1
WV-1	15813.333	417922.2	3.78%	WV-1	5348.666	152099.9	3.52%	-0.27%	0
WV-2	7032.668	414837.9	1.70%	WV-2	2449.333	146053.3	1.68%	-0.02%	0
WV-3	1428	430440.1	0.33%	WV-3	2274.666	158134.5	1.44%	1.11%	1
WV-4	4152.235	406830.1	1.02%	WV-4	1512.434	145856.7	1.04%	0.02%	1
WV-5	2720	400606.4	0.68%	WV-5	1780.669	142880.3	1.25%	0.57%	1
WYO-1	427894.744	8090725	5.29%	WYO-1	231865.6	3197056	7.25%	1.96%	1
Grand Tota	21725442.3	2.51E+08	6.47%	Grand Tota	10327962	99942398	7.98%	1.51%	
								Total	36
								No. Units	41
								% WE> WD	88%

Exhibit ICNU/111
Comparison of Modeling Methods - May 2009
GRID MODEL - July Filing

Scenario	NPC ($M)	Delta* ($M)	==Currant Creek=== Heat Rate	mWh
1 Company July Filing	1,128.63	0.00	9.18	116,234
2 Derate Modeling	1,126.94	-1.69	7.38	120,908
3 CC off 16 Days	1,127.13	-1.50	7.37	103,496
4 CC 0% Availability	1,129.08	0.45	NA	0
5 CC 100% Availability	1,125.37	-3.26	7.36	209,979
6 Norm. Composite	1,127.22	-1.40	7.36	104,990
7 Actual Average May 2006 May 2007			7.31	160,887

Notes:

1. This exhibit shows the resulting NPC and Currant Creek Heat Rates for May 2009 based on the July 2008 filing. At that time, the Company modeled Currant Creek using a monthly outage rate based on 2006 and 2007 data only. In that period Currant Creek had an outage for nearly the entire month of May 2006, and was available most of the time in May 2007.
2. Scenario 1 is the Company result based on the July 2008 GRID study filed by the Company.
3. Scenario 2 is the result based on the proposed deration adjustment to minimum loadings and the units heat rate curves described in the testimony.
4. Scenario 3 takes Currant Creek off line half of the days in May 2009 to test the reasonableness of the results from Scenario 1 and 2. Scenario 4 should approxmimate the correct result. This would approximate the impact of a 50% outage rate in May 2009.
5. Scenarios 4 and 5 test the reasonableness of overall results as well. In scenario 5 the unit is offline all of the month, approximating 2006 conditions. Scenario 5 shows the unit on the entire month (no outages) approximating 2007 condtions. The aveage of the two cases (Scenario 6) should provide another means of testing the reasonableness of the results, as it represents what actually happened.
6. As the figures show, the Company method is an "outlier" in that it does not produce results comparable to either scenario 3 or 6 and departs subtantially from actual results for May 2006 and May 2007 combined. Scenario 2, however, is in excellent agreement with the results of Scenarios 3,6 and 7.

* Delta is computed against Company base case.

UE-090205/PacifiCorp
March 12, 2009
ICNU Data Request 1.17 – 1st Supplemental

ICNU Data Request 1.17

Please provide hourly generator logs for each wind, coal, gas and hydro unit modeled in GRID for the Four-Year Period as defined above. Please provide this information electronically in excel spreadsheets with all formulas intact.

1st Supplemental Response to ICNU Data Request 1.17

The Company received a request for clarification from Mr. Falkenberg on March 9, 2009. In response, the Company supplements its original response dated March 4, 2009, with the following additional information. Referencing Attachment ICNU 1.17:

- **Jim Bridger – hourly generator logs by plant versus unit** - PacifiCorp and Idaho Power's partnership share in Jim Bridger is based on plant ownership, not unit ownership. Metering is not available to measure PacifiCorp's share of unit output.

  With regard to the Company's response to ICNU Data Request 1.70; specifically Attachment ICNU 1.70, the column entitled "Actual Hourly Generation (MW)" results from a mathematical formula used to calculate losses. It is not a reliable measure of hourly generation.

- **Colstrip** – Hourly meter data is only available at the contractual interchange point. The available metering combines the PacifiCorp ownership share of units 3 and 4.

In summary, the plant data provided in response to ICNU 1.17 is the best data available with regard to PacifiCorp's share of hourly generation at Jim Bridger and Colstrip.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-090205/PacifiCorp
March 4, 2009
ICNU Data Request 1.70

ICNU Data Request 1.70

To the extent that the Company has used any adjustment for "ramping" of thermal units in GRID, please provide the same information as was provided in CCS DR 18.49 from the current Utah General Rate Case, but for the outage rates used in the current case test year.

Response to ICNU Data Request 1.70

Please refer to Attachment ICNU 1.70.

PREPARER: Hui Shu

SPONSOR: Hui Shu

Docket: UE-090205 / Washington GRC 2009
ICNU Data Request 1.70

All January Months for the 48 months Ending June 2008

Off - line events following which ramping losses are possible					→	Applicable hours following Off-line periods and calcu				
Unit ID	Event Type	Beg Date/Time	End Date/Time	Associated Event No.		Unit ID	Hour Ending	Avail. MW	Actual Hourly Generation (MW)	Calculated Loss
JB-1	U1	01/04/2005 14:01	01/04/2005 18:28	27		JB-1	01/04/2005 20:00	530	259	271
						JB-1	01/04/2005 21:00	530	348	182
JB-1	U2	01/18/2008 14:22	01/19/2008 09:43	28		JB-1	01/19/2008 11:00	530	140	390
						JB-1	01/19/2008 12:00	530	321	209
JB-1	U2	01/30/2008 03:16	01/31/2008 08:45	29		JB-1	01/31/2008 10:00	530	75	455
						JB-1	01/31/2008 11:00	530	166	364
						JB-1	01/31/2008 12:00	530	263	267
JB-2	U1	01/16/2006 01:34	01/17/2006 16:47	30		JB-2	01/17/2006 18:00	530	73	457
						JB-2	01/17/2006 19:00	530	193	337
						JB-2	01/17/2006 20:00	530	287	243
JB-2	U1	01/18/2008 10:36	01/19/2008 17:52	31		JB-2	01/19/2008 19:00	530	55	475
						JB-2	01/19/2008 20:00	530	141	389
JB-3	U1	01/19/2005 15:33	01/19/2005 17:08	32		JB-3	01/19/2005 19:00	530	213	317
						JB-3	01/19/2005 20:00	530	280	250
						JB-3	01/19/2005 21:00	510.167	468	42.167
JB-3	U2	01/17/2008 22:34	01/19/2008 02:49	33		JB-3	01/19/2008 04:00	530	67	463
						JB-3	01/19/2008 05:00	530	285	245
JB-4	U3	01/26/2005 02:26	01/28/2005 09:53	34		JB-4	01/28/2005 11:00	530	48	482
						JB-4	01/28/2005 12:00	530	147	383
						JB-4	01/28/2005 13:00	530	126	404
JB-4	U3	01/28/2006 03:24	01/29/2006 21:25	35		JB-4	01/29/2006 23:00	530	68	462
						JB-4	01/30/2006 00:00	530	103	427
						JB-4	01/30/2006 01:00	530	261	269
						JB-4	01/30/2006 02:00	530	450	80
JB-4	SF	01/12/2007 14:00	01/12/2007 21:27	36		JB-4	01/12/2007 23:00	530	104	426
						JB-4	01/13/2007 00:00	530	225	305
JB-4	U1	01/04/2008 05:20	01/05/2008 13:31	37		JB-4	01/05/2008 15:00	530	121	409
						JB-4	01/05/2008 16:00	530	322	208

UE-090205/PacifiCorp
March 4, 2009
ICNU Data Request 1.52

ICNU Data Request 1.52

Please provide workpapers used to derive the outage rates for hydro units. Please provide the source data showing each hydro outage event (unit, data, time, lost energy, hours duration, event type, cause, NERC cause code, etc.) considered in the events.

Response to ICNU Data Request 1.52

The following is a brief summary of the outage normalization process.

Normalized Outage Procedure Summary as of November 7, 2008.

1. Request planned and forced outages 2004 – 2007. Please refer to Attachments ICNU 1.52 -1 and ICNU 1.52 -2 for data through December 2006. Please refer to Confidential Attachments ICNU 1.52 -3 and ICNU 1.52 -4 for calendar year 2007 data. This confidential information is provided subject to the terms and conditions of the protective order in this proceeding.
2. Sort outages by plant and convert length from hours to days.
3. Use pivot table to average the number of days offline per month at each plant.
4. Sum the forced and planned outages to get average outage days per month between 2004-2007.
5. Create outage cases for each river based on the average outage days per month.
    a. For months with a high number of outage days the outages were scheduled in weekly blocks
    b. Months containing less than 1 average outage day were often ignored or combined
    c. The sum of the yearly outages at each plant must equal to the average obtained from the pivot table
    d. The scheduled times for the outages were based on both the pivot table results as well as the outage placement in the previous normalized outage case prepared for 2003-2006. If an existing outage placement matched the current data no update to the outage was made
    e. There is no differentiation between forced and planned outages in the final outage forecast

This process is used for the Lewis, Klamath, and North Umpqua Rivers.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
March 11, 2008
ICNU Data Request 1.73

ICNU Data Request 1.73

Please reference Exhibit No.____ (HS-1T), page 3, lines 19-23. Please explain how and provide supporting workpapers or numerical examples showing how the forced outage rates for hydro units are reflected in the GRID data.

Response to ICNU Data Request 1.73

Once the 48-month outages have been tabulated (please refer to the Company's response to ICNU Data Request 1.75), an outage schedule is developed and the dates and duration are entered into the VISTA model and the model is run allowing the model to optimize the hydro generation around the schedule.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
March 11, 2008
ICNU Data Request 1.74

ICNU Data Request 1.74

Please reference Exhibit No.___ (HS-1T), page 3, lines 19-23. Please explain how and provide supporting workpapers or numerical examples showing how scheduled outages for hydro units are reflected in the GRID data.

Response to ICNU Data Request 1.74

Dates and times of a normalized outage schedule for each unit is an input to VISTA. The VISTA model then optimizes the available stream flow around the outages to the extent possible. The resulting hydro generation that is provided to GRID has the effects of outages incorporated. Please refer to the Company's response to ICNU Data Request 1.73 for further discussion of normalized outage schedule.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
March 11, 2008
ICNU Data Request 1.75

ICNU Data Request 1.75

Please reference Exhibit No.___ (HS-1T), page 3, lines 19-23. Please provide workpapers used to derive the outage rates for hydro units. Please provide the source data showing each hydro outage event (unit, data, time, lost energy, hours duration, event type, cause, NERC cause code, etc.) considered in the events.

Response to ICNU Data Request 1.75

The outage events for the 48-month record (2003-2006) are provided in Attachment ICNU 1.75. In addition to the official Company record of outages, calculations were added to allow the outage hours to be tabulated by unit by month. The attachment includes both scheduled maintenance and forced outages, the monthly tabulation and the business rules that guided the conversion into a schedule of outages.

PREPARER: Hui Shu

SPONSOR: Hui Shu

Docket: UE-080220 / Washington GRC 2008
ICNU Data Request 1.75

	Clearwater 1	Clearwater 2	Copco 11	Copco 12	Copco 21	Copco 22	Eastside	Fish Creek	Iron Gate	JC Boyle 1	JC Boyle 2	Lemolo 1	Lemolo 2	Merwin 1
Combined Planned and Forced (Average Hours per Month)														
1	0	54	4	34	2	2	-	10	0	16	21	5	47	7
2	32	3	2	2	1	1	2	7	1	62	11	91	-	11
3	2	44	15	8	0	1	4	1	70	24	9	2	3	13
4	41	1	18	19	1	0	1	3	36	34	9	31	96	36
5	62	146	5	9	53	61	1	1	36	53	114	194	16	41
6	-	201	10	1	44	37	0	3	1	82	265	360	0	67
7	0	57	22	15	46	19	0	3	23	5	188	231	71	170
8	4	58	13	7	0	0	31	6	5	196	231	187	96	132
9	1	4	25	132	35	139	2	180	2	183	183	148	45	56
10	72	1	23	7	27	30	19	64	-	239	304	86	2	40
11	1	1	17	38	2	2	2	5	-	228	53	4	1	32
12	-	-	1	1	4	2	-	7	1	107	71	0	0	4
Annual Total Days/'	**9**	**24**	**6**	**11**	**9**	**12**	**3**	**12**	**7**	**51**	**61**	**56**	**16**	**25**

Scheduling guidelines

Replace selected planned outages that are designated as an upgrade with a two week outage
If days/year is less than 7 schedule all days in month of highest outage starting Monday at 8:00
If days/year is greater than 7 schedule outages shaped similar to annual shape of outage. Shooting for weekly outage starting on Mondays
Schedule Swift 2 to corespond to swift 1 outages
If two or more units from the same plant are out in the same month schedule consecutively except Swift 1 which needs to 1 week outage overlapping all units, usually in October
If two or more units from the same river are out in the same month consider any corelation among plants on same river.

07-035-93/Rocky Mountain Power
March 11, 2008
CCS 15th Set Data Request 15.5

CCS Data Request 15.5

NPC GRID Modeling. Reference the response to CCS 11.7. Does the scheduling of outages for hydro units addressed in this response have an impact on the monthly, seasonal or annual energy production of storage hydro units? In other words, when a storage hydro unit has a scheduled outage, is the energy that would otherwise be produced by the unit removed from the test year, or is it assumed it will be stored and used later. Using a numerical example, please show how this is reflected in GRID and the impact on TY NPC results.

Response to CCS Data Request 15.5

Scheduling of outages does have an impact on energy production. When a storage unit has a scheduled outage the energy that might otherwise be produced is moved to another time – either before or after the outage. The VISTA model makes that decision regarding how to best reschedule generation using its optimization logic. Because the outage has placed an additional restriction on the system operations, the resulting energy and/or value of energy will be less than without the outage. Attachment CCS 15.5 provides the impact of a single outage under a single water condition.

Docket: 07-035-93 / Utah GRC 2007
CCS Data Request 15.5

Example results showing the impact of a 5 day outage of a single unit on the Lewis River

	No Outage Case		Add Outage		Difference		Cumualitve
Date	MWh	$K	MWh	$K	MWh	$K	
6/4/2007	41382.4	2163.7	41382.4	2163.7	0	0	0
6/11/2007	25453.7	1369.5	25453.7	1369.5	0	0	0
6/18/2007	29897.3	1576.2	29897.3	1576.2	0	0	0
6/25/2007	24334.4	1311	24334.4	1311	0	0	0
7/2/2007	41508.9	2495.5	41508.9	2495.5	0	0	0
7/9/2007	31279.5	2019.4	31279.5	2019.4	0	0	0
7/16/2007	29816.3	1947.3	29816.3	1947.3	0	0	0
7/23/2007	29897.3	1950.9	29897.3	1950.9	0	0	0
7/30/2007	27401.8	1758.8	27401.8	1758.8	0	0	0
8/6/2007	28010.2	1735.6	28010.2	1735.6	0	0	0
8/13/2007	26146	1637.2	26146	1637.2	0	0	0
8/20/2007	27550.4	1708.8	27550.4	1708.8	0	0	0
8/27/2007	32520.6	1927.7	32520.6	1927.7	0	0	0
9/3/2007	4663.9	250.3	4663.9	250.3	0	0	0
9/10/2007	4893.9	264.4	4893.9	264.4	0	0	0
9/17/2007	2304.8	117.2	2304.8	117.2	0	0	0
9/24/2007	2253.3	114.6	2253.3	114.6	0	0	0
10/1/2007	39740.5	2454.9	39740.5	2454.9	0	0	0
10/8/2007	38321.6	2370.8	38321.6	2370.8	0	0	0
10/15/2007	41587.8	2565.9	41587.8	2565.9	0	0	0
10/22/2007	41605.1	2555.8	41605.1	2555.8	0	0	0
10/29/2007	43208.8	2683.8	43208.8	2683.8	0	0	0
11/5/2007	61377.2	3852.2	61377.2	3852.2	0	0	0
11/12/2007	77084.2	4823.4	77084.2	4823.4	0	0	0
11/19/2007	74631	4620.5	74631	4620.5	0	0	0
11/26/2007	69290.4	4448.5	71490.8	4583.2	-2,200	-135	2,200
12/3/2007	70128.5	4525.9	72914.7	4688.5	-2,786	-163	4,987
12/10/2007	74492.6	4796.7	74248	4776.9	245	20	4,742
12/17/2007	64718.3	4187.2	68018.5	4395.9	-3,300	-209	8,042
12/24/2007	63910.5	4086.4	59804.7	3835.5	4,106	251	3,936
12/31/2007	58435.6	3533.2	59258.9	3573	-823	-40	4,760
1/7/2008	72128	4326.9	70057.2	4208.8	2,071	118	2,689
1/14/2008	66866.7	4012.9	64660.9	3890.4	2,206	123	483
1/21/2008	73887	4422.5	79328.5	4723.7	-5,442	-301	5,925
1/28/2008	68819	4061.3	69378.3	4092	-559	-31	6,484
2/4/2008	63858.3	3718.9	66985.8	3903.7	-3,128	-185	9,611
2/11/2008	75965.4	4384.1	76041.9	4390.7	-77	-7	9,688
2/18/2008	69152.2	4007.7	69185.2	4013.7	-33	-6	9,721
2/25/2008	62314	3536.9	64283.7	3636.2	-1,970	-99	11,691
3/3/2008	53694.2	2749.1	46153.5	2363.3	7,541	386	4,150
3/10/2008	48897.1	2498.4	45992.2	2346.5	2,905	152	1,245
3/17/2008	69589.1	3522.5	54240.5	2748.9	15,349	774	-14,104
3/24/2008	71189.2	3606.4	71158.9	3599.9	30	7	-14,134
3/31/2008	25004.6	1120.4	29766.4	1338.4	-4,762	-218	-9,372
4/7/2008	23325.5	1017.5	31294.9	1353.3	-7,969	-336	-1,403
4/14/2008	30292.9	1314.8	27664.1	1210	2,629	105	-4,032
4/21/2008	29228.4	1270.3	31452.8	1361.6	-2,224	-91	-1,807
4/28/2008	6073.5	220.8	6073.5	220.8	0	0	-1,807
5/5/2008	37605.1	1508.8	38310.5	1531.7	-705	-23	-1,102
5/12/2008	32545.4	1286.2	35136.1	1391	-2,591	-105	1,489
5/19/2008	43860.9	1715.3	45232.2	1774.2	-1,371	-59	2,860
5/26/2008	34761.8	1342.3	33795.6	1300.6	966	42	1,894
6/2/2008	35932.9	1384.5	32264.2	1244.4	3,669	140	-1,775
Total	2,322,838.0	132,881.8	2,321,063.4	132,772.2	1,775	110	13%

08-035-38/Rocky Mountain Power
November 3, 2008
CCS Data Request 20.5

CCS Data Request 20.5

NPC GRID: Please refer to Attachment CCS 10.48. In reviewing this file, the CCS noticed over 100 hours when the available capacity of a unit was zero, but generation was greater than zero. Please explain why this happens. For example, see the following hours for Cholla 4:

2/21/62 12:00 AM
4/3/04 1:00 AM
5/6/04 11:00 PM
5/8/**04 8:00** PM
6/13/04 6:00 PM
6/20/04 3:00 AM
7/10/04 1:00 AM
7/26/04 6:00 AM
8/5/04 6:00 PM
4/9/05 2:00 AM
4/10/05 9:00 AM
6/10/05 1:00 AM
8/13/05 2:00 AM
10/23/05 4:00 AM
8/24/06 10:00 AM
10/6/06 10:00 AM
4/21/07 2:00 AM
6/8/07 11:00 AM
9/9/07 3:00 AM
9/9/07 9:00 AM
9/21/07 2:00 AM
9/28/07 6:00 PM

Response to CCS Data Request 20.5

Such instances mainly occurred at the Cholla 4 unit, where the hourly availability is represented in standard time and the generation is represented in daylight savings time. There may also have been updates to the generation files that were not correlated to the availability information. In general, the availability of a unit should closely coincide with the generation pattern.

The Company will revise its ramp loss calculation for Cholla 4 to correct the inconsistency between standard time and daylight saving time on rebuttal. In addition, due to lack of data for the plants that the Company is not an operator of (Colstrip, Craig and Hayden), there is not adjustment for ramping losses. As the result, the net power costs are understated in the Company's filing.