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April 7, 2009

Via Electronic Filing and U.S. Mail

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

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

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

/s/ Kay Barnes

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PUBLIC UTILITY COMMISSION
OF OREGON

UM 1355

STAFF OPENING TESTIMONY OF

Kelcey Brown

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

April 7, 2009

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

April 7, 2009

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

A. My name is Kelcey Brown. I am a Senior Economist in the Electric and Natural Gas Division at the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony I will discuss the Commissions current policy on the calculation of not only forced outage rates, but the total calculation of availability for electric generation units. I will provide my conclusions and recommendations regarding how the availability of an electric generation unit should be calculated for ratemaking purposes. In addition, I will make recommendations on the use of Industry data to be used as a benchmark when setting forced outage rates. I also recommend additional reporting requirements for wind generation facilities.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I will first provide a brief summary of my conclusions and recommendations. By way of background, I will describe the purpose of forced outage rates and explain why the Commission recommended this docket be opened.

I will organize the remainder of my testimony to address each of the issues in the Consolidated Issues List filed January 30, 2009. I also provide Exhibit

Staff/103-105 that details the statistical calculations and data that supports my recommendations.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. After a thorough review of historical generation unit outage data I have reached the following conclusions:

1. I agree with the Commission's statement in Order No. 07-015 (UE-180) that the historical performance of the generating unit is the best predictor of what will occur in the future.
2. I recommend that the formula used to calculate overall availability, and specifically forced outage rates, be changed. I will show that it is appropriate to separately calculate and model forced outage rates, planned outage rates, and a deferrable maintenance outage rate in order to accurately calculate availability for ratemaking purposes. I am defining a "forced outage" as an unplanned event that causes a generation facility to shutdown or reduce capacity immediately. "Planned outages" are outage events that are scheduled more than one year in advance. Finally, "maintenance outages" are outage events and reduced capacity events that are scheduled in a relatively short time frame (i.e. a few days to less than one year).
3. I propose the use of industry data provided by the North American Electric Reliability Council (NERC) for benchmark purposes, in order to objectively define the level at which a plant has experienced an extreme

forced outage event, or on a cumulative basis, an extreme forced outage year. The definition of an extreme outage event generally refers to an extended time period, beyond what would be considered "normal." The benchmark will be set according to a discrete probability distribution[1] of the industry outage information, with the benchmark set at less than 10 percent probability of occurrence. This tool will allow the Commission to objectively define whether the reported forced outage rate is reasonably likely to occur in the test period. If the benchmark shows that the rate is unlikely to occur in any given year, then an adjustment will be made to the forced outage rate.

4. The appropriate application of a forced outage rate on hydroelectric units, specifically storage hydroelectric units, should not cause an overall decrease in total MWh produced by the facility for the year. If a utility were able to show that a hydroelectric unit was forced to spill water in every occasion that it experienced a forced outage, then a decrease in total output would be appropriate; however, I have not found this to be the case.

5. Non-base load resources (e.g., gas fired peaking plants) require a different formula than that of base load resources (e.g., coal generation

[1] A discrete probability distribution is a statistical term that means the description of a range of possible values (e.g. the forced outage rates of all reporting units) that a random variable (e.g. forced outage rate of a single unit) can attain, and the probability of that value falling within that range. For a graphical illustration of a probability distribution *see* Exhibit Staff/105, Brown/6. Stated differently, given the reported forced outage rates of 58 coal-fired generating units that are between 600-699 MW in 2007, the probability that a unit will incur a forced outage rate of greater than 10 percent has a less than 10 percent probability of occurrence, or is unlikely to occur.

facilities). I propose the Commission use NERC's equivalent forced outage rate (demand) (EFOR(d)) formula.

6. Finally, I propose the Commission require the utilities to provide a wind availability report for each wind facility on an annual basis that will show:
   A. Maximum net output of the facility given the actual wind conditions in a calendar year.
   B. Lack of availability due to planned maintenance.
   C. Lack of availability due to line loss.
   D. Lack of availability due to forced outages, turbine failure, or non-scheduled maintenance.
   E. Then, subtract factors B, C, and D above from A to provide the actual capacity factor for a wind facility in a calendar year.

This information will provide a useful history that will allow the Commission to obtain a better understanding of the different factors that affect the actual output of wind facilities. For ratemaking purposes, this information will provide an historical record that will facilitate a future determination of the appropriate methodology for calculating the capacity factor of wind farms in a test year.

<u>Forced Outage Rate Overview</u>

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF FORCED OUTAGE RATES AND EXPLAIN THEIR PURPOSE.

A. A forced outage is an unplanned failure that causes immediate shutdown of a generating unit. Broadly speaking, the forced outage rate is calculated as a proportion of forced outage hours to total hours that the unit is available for operation. To calculate test period power costs for ratemaking, the Commission uses a "forced outage rate" as part of the determination of normalized generating unit availability. Since 1984, the Commission has used a four-year rolling average of actual unit forced outage rates for a prediction of what will potentially occur in the test period.

Q. ARE THERE OTHER OUTAGE EVENTS THAT ARE USED IN THE CALCULATION OF AVAILABILITY OF A THERMAL GENERATION PLANT?

A. Yes. There are several types of outage events that are used in the overall calculation of availability of a thermal generation facility. As stated in my summary of conclusions, for simplicity I am defining them as: forced outage events (immediate shutdown or de-rate), maintenance outage events (scheduled in a relatively short time frame, less than one year), and planned outage events (scheduled in a time frame that is greater than one year). These three generic descriptions are intended to capture all the outage events that a generation facility will incur, and contribute to the calculation of its overall availability.

Q. PLEASE SUMMARIZE THE ISSUE OF FORCED OUTAGE RATES IN DOCKET UE 180, ORDER NO. 07-015.

A. In UE 180, Order No. 07-015, one of the issues before the Commission was the treatment of the extreme outage events that occurred at the Boardman and Colstrip coal plants. In UE 180, Staff and other intervening parties questioned the four-year rolling average methodology and its ability to adequately account for extreme events when calculating a future test year forced outage rate that had a likely probability of occurrence.

Q. WHAT WAS STAFF'S RECOMMENDATION IN UE 180 FOR CALCULATING A FORCED OUTAGE RATE FOR THE TEST PERIOD?

A. In UE 180, Staff recommended that Portland General Electric (PGE) discontinue using actual forced outage rates and instead use industry forced outage rate information provided by NERC, and the use of a standard peer group.[2] Staff concluded that the current methodology of a four-year rolling average assigned too much weight to recent extreme events, resulting in an unrealistic outage rate for the test period.

Q. PLEASE SUMMARIZE THE COMMISSION DECISION IN ORDER NO. 07-015 (UE 180).

A. In relevant part, the Commission stated that it sought "…the most accurate forecast of forced outages at the relevant plants."[3] The Order went on to say that "We continue to believe that past performance is the best predictor of a plant's outage rate." *Id.* In addition, the Commission concluded that the events that occurred at the respective plants were "extreme events" and directed that the associated hours be removed from the calculation of forced outage rates.

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

The Commission then ordered that a generic docket be opened to further investigate the currently-used forced outage rate methodology. UM 1355 is that docket.

Q. PLEASE EXPLAIN THE ORIGIN OF THE CURRENT COMMISSION POLICY FOR CALCULATING OUTAGE RATES AND OVERALL AVAILABILITY?

A. In 1984, then-Commission Staff member Tom Harris proposed an equivalent outage rate methodology. This method took into account the different outage types (e.g. forced, maintenance, scheduled, and planned)[4] and used a four-year rolling average of actual plant performance in order to estimate what the equivalent outage rate of the plant would be for purposes of calculating power costs. Mr. Harris provided a formula for calculating the equivalent outage rates within each year.[5]

Q. IS THIS METHOD STILL EMPLOYED TODAY BY THE COMMISSION?

A. Yes. The original formula that was proposed by Staff witness Thomas Harris is still an integral part of a Utility's calculation of a generation facility's overall availability factor. However, each individual utility has some unique differences in how it applies this method to different types of generation facilities and how it models this calculation within a test year.

Q. PLEASE PROVIDE SOME EXAMPLES OF THE DIFFERENCES BETWEEN EACH UTILITY.

[4] These outage types are not to be confused with my definitions provided previously.
[5] For a full copy of the 1984 Staff memo please see Exhibit Staff/102, Brown/1-21.

A. There are many differences between each utility. Four specific examples of these differences are:

1. While Idaho Power does not model forced outages on its gas-fired generation facilities, both PGE and PacifiCorp do;
2. In its last net variable power cost (NVPC) filing, PacifiCorp introduced a forced outage methodology for some of its hydroelectric generation facilities. No other utility models forced outages on its hydroelectric generation units;
3. PacifiCorp uses a four-year rolling average in the calculation of a planned outage rate for purposes of the test year. PGE and Idaho Power forecast their planned outages in the test year, taking into account specific maintenance that the utility is planning to perform; and
4. Until recently, PacifiCorp modeled a weekend/weekday split of its outages, taking into account the ability of the operator to defer certain outages to periods that have a lower economic impact on variable power costs.

Outage Rate Methodology

Q. PLEASE REPRODUCE THE FORMULA FROM MR. HARRIS' 1984 MEMO.

A. Reproduced below is the formula that was recommended and approved in 1984, and is still in current use today:[6]

$$EOR = \frac{FOH + EFOH + MOH + ESOH}{SH + FOH + MOH}$$

[6] For a full explanation of the formula and definitions please review Exhibit Staff/102, Brown/5-7.

EOR = Equivalent outage rate – For our purposes this is the Forced outage rate.
FOH = Forced outage hours – Time in hours during which a unit is unavailable.
EFOH = Equivalent forced outage hours – For a forced partial de-rate this is the equivalent time in hours for a full forced outage.
MOH = Maintenance outage hours – The time in hours during which a unit is unavailable due to a maintenance outage.
ESOH = Equivalent scheduled outage hours – The time in hours for a partial maintenance de-rate. Scheduled outage hours and maintenance outage hours are scheduled a relatively short time (i.e. a few days) in advance. These are distinguished from planned outages, which are scheduled months or years in advance.
SH = Service hours – The total number of hours that the unit was actually operated with the breakers closed to the station bus.

<u>Issue I.D: What forced outage rate methodology should the Commission adopt for coal-fired generating plants?</u>

Q. PLEASE DISCUSS WHETHER YOU CONTINUE TO SUPPORT THE CURRENTLY-USED COMMISSION FORMULA FOR CALCULATING FORCED OUTAGE RATES.

A. I do not support the formula that the Commission currently uses for calculating forced outage rates. As I will discuss in more detail, because of issues that the Commission has faced in regard to planned outages, and observations of the utility practice in scheduling maintenance outages during times that are economically favorable, I am proposing the Commission adopt a new set of formulas to be applied to all of the utilities participating in this docket.

Q. PLEASE SET FORTH YOUR RECOMMENDED FORMULAS.

A. I recommend the following three formulas (corresponding to three different types of outages) for application to coal generation facilities:

$$FOR = \frac{FOH + EFOH}{PH}$$

$$MOR = \frac{MOH + EMDH + EPDH}{PH}$$

$$POR = \frac{POH}{PH}$$

$$\text{Equivalent Availability Factor} = 1 - (FOR + MOR + POR)$$

FOR = Forced outage rate – This will continue to be modeled in the test year as it is currently done in the Utility's least-cost dispatch models.

FOH = Forced outage hours- The time in hours during which a unit is unavailable due to a forced outage.

PH = Period hours – Total hours in a calendar year, where the only variation would be a leap year versus a non leap year.

MOR = Maintenance outage rate – This will be the outage rate associated with deferrable maintenance. The application of this rate will differ from that of the forced outage rate, in test year modeling, to reflect actual plant history of occurrence within heavy load hours and light load hours. (I will discuss this further in testimony.)

MOH = Maintenance outage hours – The time in hours that a unit is unavailable due to a maintenance outage. These outages are scheduled in a relatively short time frame (i.e. a few days to a week) in advance.

EMDH = Equivalent maintenance de-rated[7] hours – An outage that requires a reduction in capacity, and is calculated as equivalent to the time in hours of a full forced outage event. These outages are scheduled in a relatively short time frame (i.e. a few days to a week) in advance.

EPDH = Equivalent planned de-rated hours – An outage that requires a reduction in capacity and is calculated as equivalent to the time in hours of a full forced outage event. These outages are scheduled in a short time frame (i.e. weeks to months) in advance. The planning period for these outages is longer than the EMDH, but shorter than the planned outage hours which are scheduled typically up to one year in advance.

POR = Planned outage rate – Will be modeled as a four-year rolling average of actual planned maintenance. This will be applied to the Utility's NVPC model and should be scheduled to occur during times that will realize the least impact on NVPC.

POH = Planned outage hours – The time in hours that a unit is scheduled to be unavailable due to annual planned maintenance. These outages are scheduled with a long lead time, typically greater than one year in advance.

[7] The term "de-rated" refers to a reduction in the net available capacity of the unit. For example, assume a unit had a net available capacity of 100 MW, but due to a necessary maintenance the units net available capacity was reduced to 80 MW. This reduction in available capacity from 100 MW to 80 MW is referred to as a "de-rate." If this reduction in available capacity lasted five hours, than the calculated equivalent de-rated hours would be 20 MW * 5 hours = 100 MWhs/100 MW = 1 hour of equivalent maintenance de-rated hours for the facility.

Equivalent Availability Factor (EAF) = This factor includes the effects of all outage events, and is equivalent to the percentage of time during which the unit was available for operation at full capability.

Maintenance Outages

Q. WHAT IS THE DIFFERENCE BETWEEN A MAINTENANCE OUTAGE AND A PLANNED OUTAGE?

A. These two terms are very similar; however, they are very different in terms of scheduling. The ability of a utility to schedule its outages is very important in terms the impact that these outages have on power costs. Again, I am defining a maintenance outage as an outage that is scheduled in advance in a relatively short time frame, i.e. less than one year, and a planned outage is an outage that is scheduled in advance in a time frame that is greater than one year.

Q. PLEASE DISCUSS THE REASON FOR YOUR PROPOSED CHANGE IN METHODOLOGY AND MODELING OF MAINTENANCE OUTAGES.

A. On a modeled basis, in the test year, the current Commission method treats maintenance outages the same as randomly occurring forced outages: it evenly distributes them across all hours throughout the year. This modeling method does not take into account the differences between a deferrable maintenance outage and a forced outage, which necessitates immediate shut-down of the unit.

Q. WHEN A UTILITY SCHEDULES A MAINTENANCE OUTAGE, DOES IT TAKE INTO ACCOUNT MARKET PRICES AND THE COST OF REPLACEMENT POWER?

A. Yes. In Staff Data Request (DR) No. 5 each utility was asked to provide the actual occurrence of maintenance outage hours (MOH, EMDH, and EPDH) within high load hours[8] and within low load hours[9] over the last four known years. PacifiCorp provided the most comprehensive response,[10] which showed that on average for coal plants the occurrence of deferrable maintenance within high load hours was approximately 43 percent. The occurrence of deferrable maintenance during low load hours was 57 percent. The current methodology uses and evenly distributed calendar year, which has a ratio of high load hours to low load hours of 55 percent high load hours and 45 percent low load hours. Therefore, under the current Commission method customers are not realizing the benefit of the actual utility practice of scheduling the deferrable maintenance during times that have the least price impact.

Q. WILL THIS CHANGE IN MODELING CAUSE A DECREASE IN NVPC?

A. Yes. Changing the way that the utility currently models its maintenance outages will cause a decrease in NVPC. This change in modeling is appropriate because it will more accurately track the practice of the utility to schedule its maintenance during times that have the least impact on power costs.

[8] High Load hours refers to a frame of time during a 24 hour day when customer load and market prices are higher, i.e Monday through Saturday 6:00 am – 10:00 pm.
[9] Low Load, or Light Load, hours refers to a frame of time during a 24 hour day when customer load and market prices are lower, i.e. Monday through Friday 10:00 pm – 6:00 am and Saturday 10:00 pm to Monday at 6:00 am.
[10] *See* Exhibit Staff/103, Brown/1. This Exhibit includes a pivot table of the PacifiCorp provided data, which adds up the four years of reported data, shows only coal plants, and shows the ratio calculation of high load to low load hours.

Q. IS IT DIFFICULT FOR THE UTILITY TO TRACK THE OCCURRENCE OF ITS OUTAGES ON AN ACTUAL BASIS DURING HIGH LOAD AND LOW LOAD HOURS?

A. No. The utility currently tracks and reports its maintenance events with a start time and an end time. Once this time period is known, it is a simple calculation to determine whether this period of time occurred during high load or low load hours.

Q. HOW DO YOU PROPOSE TO CALCULATE THE MAINTENANCE OUTAGE RATIO OF HIGH LOAD TO LOW LOAD HOURS FOR MODELING PURPOSES?

A. Just as in the forced outage rate calculation, I recommend the use of a four-year rolling average of the utility's actual history of maintenance outages that occur during high load and low load hours.

Q. HAVE ANY OF THE THREE UTILITIES EVER MODELED FORCED OUTAGES TO TAKE INTO ACCOUNT SPECIFIC TIMES DURING THE WEEK OR DAY?

A. Yes. Until recently, within the last year, PacifiCorp calculated and modeled its forced outages using a weekend/weekday split. This is an approach that recognizes that if the utility has the ability to defer performing maintenance activities, it will do so during times that have the least economic impact.

Q. SHOULD YOUR PROPOSED MAINTENANCE CALCULATION AND MODELING ALSO APPLY TO GAS-FIRED FACILITIES?

A. No. I will discuss later in testimony my proposal for modeling forced and maintenance outages on gas-fired facilities.

<u>Issue IV. What methodology should the Commission adopted for planned maintenance outages, and how should it be applied?</u>

Q. PLEASE DISCUSS YOUR PROPOSED METHODOLOGY IN CALCULATING AND MODELING PLANNED OUTAGES IN A TEST YEAR.

A. The planned outage rate will be based on a four-year rolling average of the utility's actual plant history. For ratemaking purposes this will allow planned outage events, which can occur once every four to ten years, to conform to a normalized test year.

Q. IS YOUR PROPOSED METHODOLOGY FOR PLANNED OUTAGE RATES CURRENTLY USED BY ANY OF THE UTILITIES IN THIS DOCKET?

A. Yes. PacifiCorp currently uses a four-year rolling average of its planned outages for modeling purposes.

Q. IS IT APPROPRIATE TO ALLOW A UTILITY TO FORECAST ITS PLANNED OUTAGES FOR PURPOSES OF A TEST YEAR?

A. No. The Commissions ratemaking approach is to "normalize" a test year. This means that events that only occur once every few years are not specifically modeled; they are taken into account in calculating historical averages. Therefore, it would be inconsistent with the Commission's approach to allow the utility to forecast its planned outages, which are one-time events that may vary widely from year to year.

Q. DO RECENT COMMISSION DECISIONS CONTINUE TO FAVOR NORMALIZED RATEMAKING?

A. Yes. In UE 197, Fixed Plant Costs (*Issue S-11*), Staff proposed that the one-time maintenance costs associated with PGE's forecasted test year planned maintenance should be allocated over a ten-year period.[11] PGE agreed that the maintenance was planned to occur only once every ten years, and was willing to support a ten-year recovery period, which took into account the time value of money. The Commission agreed with Staff's ten-year proposal and supported PGE's recovery of the time value of money.

Q. IN LIGHT OF THE COMMISSION DECISION TO ALLOCATE FIXED COSTS ASSOCIATED WITH ONE-TIME MAINTENANCE EVENTS, WOULD IT BE CONSISTENT TO ALLOW THE UTILITY TO MODEL ONE-TIME EVENTS IN THE TEST YEAR?

A. No.

Q. SHOULD YOUR PROPOSED PLANNED OUTAGE METHODOLOGY ALSO BE APPLIED TO GAS-FIRED GENERATION FACILITIES?

A. Yes. The current practice of using a four-year average, and scheduling planned outages during times that have the least economic impact, should also apply to gas-fired facilities.

<u>Issue I.F: What is the appropriate length for the historical period?</u>

[11] *See* Order No. 09-020, page 23.

Q. WHAT WAS THE BASIS FOR THE CURRENT COMMISSION PRACTICE OF USING A FOUR-YEAR ROLLING AVERAGE?

A. Mr. Harris explained his proposal of a 48-month period as follows: “The reason I propose using a 48-calender month rolling average is that it reflects recent plant experience, which I think tends to better portray expected operation over the coming year. Four years of experience is sufficient to average out variations and yet not include generally irrelevant experience from history long past.” *See* Exhibit Staff/102, Brown/4. In addition, at the time of Mr. Harris’ memorandum PacifiCorp used a four-year planned maintenance cycle, which further supported the use of the 48-calender month time period.

Q. DID YOU PERFORM A STATISTICAL ANALYSIS OF THE FOUR-YEAR TIME PERIOD?

A. Yes. I compiled the PacifiCorp outage data into energy lost by year and by plant, and attempted to find an underlying cyclical trend. I was unsuccessful in finding any statistically significant trend, including a four-year period, that was common among all of the generating facilities.[12]

Q. DID YOU TEST THE ABILITY OF OTHER TIME PERIODS TO MORE ACCURATELY PREDICT ACTUAL FORCED OUTAGES IN THE TEST YEAR?

A. Yes. Using plant information provided by PacifiCorp, I calculated rolling averages using different time periods, i.e. 1 year, 2 years, 3 years, 4 years, 5

[12] *See* Exhibit Staff/104, Brown/1-4 for the forecasted trend analysis. I have included four examples of the trend analysis using the PacifiCorp coal-fired facilities Jim Bridger, Carbon, Dave Johnston and Hunter.

years, and 6 years, and a rolling average that applied different weights to more recent years (i.e. 40%, 30%, 20% and 10%), as opposed to the current practice of weighting each year evenly (i.e. 25%, 25%, 25%, 25%). Using a back-cast comparison (forecasting for a year that has already occurred in order to determine how accurate it would have been), I tested each methodology for accuracy.

Q. WHAT DID YOUR RESULTS INDICATE?

A. My results indicated that a specific methodology in any given year may be the most accurate, but in the next year, after incorporating new data, a different methodology usually generated more accurate results. My overall conclusion is that forced outage rates are random, and in that randomness there is no definable pattern that can provide a statistical relationship that is greater than the current methodology of a four-year average.

Q. DO YOU CONTINUE TO SUPPORT THE USE OF A FOUR-YEAR ROLLING AVERAGE FOR PURPOSES OF CALCULATING FORCED OUTAGE RATES?

A. Yes. Based on the lack of finding a statistically significant method that produces more accurate results than the existing practice, I find no reason to recommend a change from the current practice of using a four-year rolling average with equal weighting.

Issue I.B. and I.C: Should extreme events be included in the forced outage rate determination?

Q. WHAT IS YOUR RECOMMENDATION FOR THE TREATMENT OF EXTREME EVENTS IN FORCED OUTAGE RATES?

A. For extremely long events, and for years that a unit experiences a significant number of small outages that is outside what would be considered normal, I propose that the Commission use NERC outage rate information as a benchmark to determine whether the forced outage rate for the test period is reasonable and likely to occur.

Q. IS IT A COMMON PRACTICE FOR THE COMMISSION TO USE BENCHMARKS AS A TEST OF REASONABLENESS?

A. Yes. Most recently, in UE 200 PacifiCorp's Renewable Adjustment Clause, Staff utilized benchmark data to determine whether PacifiCorp's costs for its proposed wind generation facilities were reasonable as compared to industry data.

Q. PLEASE EXPLAIN YOUR PROPOSAL TO USE NERC INDUSTRY FORCED OUTAGE RATE INFORMATION AS A BENCHMARK FOR EXTREME EVENTS.

A. I am proposing to use NERC generating unit-level information, categorized by year, fuel type and size, to determine whether the calculated forced outage rate for the test period is reasonable and falls within the range of data that is statistically likely to occur. Exhibit Staff/105, Brown/1-5, shows forced outage rate information for four categories of coal-fired units: 600-699 MW, 500-599 MW, 400-499 MW, and 300-399 MW for the years 1999 through 2007.

Q. PLEASE DISCUSS HOW YOU USED THIS INFORMATION TO DETERMINE A BENCHMARK.

A. Using the annually reported forced outage rate for each unit, I calculated a discrete probability distribution. Simply, this means that the range of possible values is contained to the reported rates for that year, i.e. the lowest rate reported and the highest rate reported sets my lower and upper limits. I calculate a greater than 90th percentile value probability of occurrence and a less than 10th percentile value probability of occurrence. This means that for the 57 coal-fired units with a rated capacity of 600-699 MW reporting in 1999, 90 percent of the time a reported forced outage rate is going to be less than 13.41 percent. At the other end of the spectrum, the likelihood that the rate will be less than 1.96 percent has a less than 10 percent chance. I performed this calculation for each year and then used these 90 and 10 percent values to calculate a four-year rolling average which will be used as the benchmark in the test year.[13]

Q. WHY IS IT NECCESARY TO HAVE BOTH A 90TH PERCENTILE VALUE AND A 10TH PERCENTILE VALUE?

A. In terms of parity, it is important to note the probability of occurrence from both sides of the mean. This is the same concept as having a true-up mechanism in NVPC, which takes into account the possibility of over-forecasting and of under- forecasting NVPC.

[13] All calculations are at the bottom of each category, by capacity, in Exhibit Staff/105, Brown/1-5.

Q. HOW DO YOU PROPOSE THE COMMISSION UTILIZE THESE 90TH PERCENTILE AND 10TH PERCENTILE VALUES AS A BENCHMARK?

A. The Commission should use the NERC data to determine whether a utility's reported forced outage rate is likely to occur within the test year. If the utility forced outage rate is larger than the 90th percentile probability of occurrence, then according to industry statistics it is unlikely to occur within the test period. The appropriate action would be to adjust the utility forced outage rate to within the likelihood of occurrence, at the 90th percentile value.

Q. WOULD THE SAME ADJUSTMENT BE MADE FOR THOSE VALUES THAT FALL BELOW THE 10TH PERCENTILE PROBABILITY OF OCCURRENCE?

A. Yes. It stands to reason that if the Commission recognizes that there are years that may be unusually bad, then they must also take into account those years that are unusually good.

Q. ONCE THIS ADJUSTMENT WAS MADE WOULD FURTHER COMMISSION ACTION BE NECESSARY?

A. No. If a utility believed it needed to recover additional power cost expenses, above what its expected rate of return is, then it has the option to file for a deferral of power cost expenses that it alleges were unreasonably high due to unforeseen events. In addition, PGE and Idaho Power have in place a true-up mechanism that allows the utility to recoup those costs that are above or below its forecasted NVPC (after the application of a deadband and an earnings review) on an annual basis. This type of mechanism further justifies the need to have a more accurate forecast of what will likely occur within the test period, rather than the current four-year rolling average method that effectively provides the utility with a retroactive ratemaking tool.

Q. HAVE YOU CONSIDERED THE TREATMENT IN UE 180, WHERE THE COMMISSION REMOVED THE TIME PERIOD OF THE OUTAGE FROM BOTH THE DENOMINATOR AND THE NUMERATOR OF THE FORCED OUTAGE RATE CALCULATION?

A. Yes. I have. In UE 180, and in other rate cases, the Commission's decision to remove the extreme outage period from the calculation has the effect of giving greater significance to those events left in place, and thus results in a relatively higher forced outage rate. For example:

100 MW plant

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Rolling Average**
Total forced outage hours	60,000	100,000	50,000	400,000	610,000
Total MWH in one year	876,000	876,000	876,000	876,000	3,504,000
Forced outage rate	7%	11%	6%	46%	17%

Commission decision in year four, removes 300,000 hours from outage calculation

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Rolling Average**
Total forced outage hours	60,000	100,000	50,000	100,000	310,000
Total MWH in one year	876,000	876,000	876,000	576,000	3,204,000
Forced outage rate	7%	11%	6%	17%	10%

As is shown, the remaining 100,000 hours in Year 4 now calculates as a 17 percent forced outage rate, while in Year 2 for the same amount of outage hours this only calculates as an 11 percent outage rate. The NERC-benchmark approach is a superior method of accounting for the type of situation addressed in UE 180.

<u>Issue I.A: Different Forecasting Method for a Peaker Plant versus a Base Load Plant?</u>

Q. SHOULD THERE BE A DIFFERENT FORECASTING METHODOLOGY FOR A GAS-FIRED PEAKING FACILITY VERSUS A BASE LOAD COAL-FIRED FACILITY?

A. Yes. Mr. Harris did not address gas-fired facilities in his 1984 memo. The utilities have used the same methodology for gas-fired plants as for coal-fired plants, but to date the Commission has not required such an approach. Gas-fired peaking facilities have very different operating schedules than a base load coal-fired facility. The time of day that a peaking plant runs and the amount of time that it will run as opposed to a coal plant is significantly different. The current method of calculating forced outages rates for peaking facilities significantly under- or over-states the availability of the unit, and leads to incorrect modeling.

Q. PLEASE PROVIDE AN EXAMPLE OF WHY THE CURRENT METHOD CAN LEAD TO INCORRECT MODELING.

A. For example, in a calendar year if a gas-fired peaking facility was called to run nine times, it would then have nine expected start times. If in one of those times it did not start, the utility would then assume a length of time that the unit would have run, and record this as forced outage hours. From a reliability perspective the unit only failed one out of nine times, which, if calculated as a forced outage rate is 11 percent. However, if during these nine start times the facility ran, or was expected to run, a total of 270 hours, and during the one outage event it was expected to run 60 hours, the calculated forced outage rate would be: 60/270 = 22%. For a 100 MW facility, it would be modeled as only available to provide power up to 78 MW for the test year.

Q. WHAT IS YOUR PROPOSAL THAT WILL BETTER CALCULATE A FORCED OUTAGE RATE OF A GAS-FIRED PEAKING FACILITY?

A. A method prescribed by NERC, called equivalent forced outage rate demand (EFOR(d)), takes into account the number of attempted starts, the number of actual starts, and the average forced outage duration. This formula will provide a more accurate calculation of forced outage rates, and subsequently more accurate modeling of these facilities in the test year.

Issue I. E: New Thermal Resources

Q. HOW SHOULD NEW THERMAL RESOURCES BE TREATED?

A. As prescribed in the 1984 Memorandum, the appropriate methodology for a new resource, with less than four years of actual plant performance data, should use NERC industry data to substitute for those years, until such time that four years of actual information becomes available. The NERC industry information should be incorporated according to fuel and capacity rating, with the average forced outage rate for that category substituted for the applicable years.

Issue I.G: Non-Outage Related Adjustments

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

A. I am unaware of any non-outage related adjustment that may be appropriate to include in the forced outage rate determination. I am unable to make a definitive statement on this issue until participants in this docket have had an opportunity to cite examples of such non-outage events.

<u>Issue I.H: New Capital Investment</u>

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

A. If the utility entered into an agreement with an outside party, in which it was guaranteed a quantified increase in reliability in a particular plant through new capital investment, subject to liquidated damages or other compensation, then it would be appropriate to reflect the guaranteed increase in reliability for the forecasted test year. Outside these conditions it would be difficult for the utility to accurately forecast an increase in reliability due to capital investment.

<u>Issue II: Hydro Availability Method</u>

Q. HAS THE COMMISSION ADOPTED A HYDRO AVAILABILITY METHODOLOGY?

A. Currently, the Commission does not have an adopted hydro availability model. Utilities are not currently required to report incidents of forced outages on hydro facilities to NERC. The definition of a forced outage incident for a hydro facility and the subsequent consequences of that outage are very different from that of a thermal facility. For example, if a coal-fired base load facility experiences a forced outage it loses the ability to produce that power. However, when a hydroelectric facility experiences a forced outage, the water is still behind the dam and will be used for generation at another time. The total production of the hydroelectric facility will not decrease for the year due to forced outages.

Q. DO PGE, IDAHO POWER, OR PACIFICORP CURRENTLY MODEL FORCED OUTAGES FOR THEIR HYDRO FACILITIES?

A. PacifiCorp is the only utility that has introduced forced outages for hydro facilities, which impacts hydro availability within its NVPC model.

Q. PLEASE DESCRIBE PACIFICORP'S FORCED OUTAGE METHODOLOGY AS IT PERTAINS TO HYDRO FACILITIES.

A. In UE 199, PacifiCorp proposed through its Transition Adjustment Mechanism filing (TAM) to include forced outages for specific hydro facilities (storage facilities). At that time, PacifiCorp utilized its Vista model to generate a weekly amount of MWh of hydro availability, which it then input into its NVPC dispatch model (GRID). GRID then took the total MWh of energy and dispatched it according to its least cost dispatch logic. The Vista model uses a monthly four-year average of "forced outage hours" from these specific storage facilities. Once the average number of forced outage hours per month is known, specific time periods within that month are selected as "unavailable." For example, in the month of April, if the average number of hours of forced outages is 50 then specific time periods, e.g. Monday, Tuesday and Wednesday in the second week of April, are unavailable to the model for generation.

Q. IS THIS METHODOLOGY CONSISTENT WITH THE PRINCIPLE OF A STORAGE HYDRO FACILITY WHICH STORES ENERGY BEHIND A DAM?

A. No. While I acknowledge that hydro facilities are not always going to be available when they are called upon, it is incorrect to use a method that does not take into consideration the fact that the hydro facility retains its ability to generate that power in the future. Unless the utility is required to spill the water due to biological constraints or other mitigating factors, and the energy capability is lost, the utility should not reflect a lower production of power from a storage hydro facility due to forced outages.

Q. HAS PACIFICORP PROVIDED AN EXAMPLE WHEN IT WAS REQUIRED TO SPILL STORED WATER RELATED TO A FORCED OUTAGE?

A. No.

Q. DOES STAFF PROPOSE A METHODOLOGY FOR FORCED OUTAGES ON HYDRO FACILITIES?

A. No. Storage hydro facilities present their own parameters of operations, which current thermal forced outage rate methodologies do not adequately address.

<u>III: What wind availability reporting method should the Commission adopt?</u>

Q. PLEASE DISCUSS YOUR RECOMMENDATION OF AN ANNUAL WIND AVAILABILITY REPORT, TO BE FILED BY EACH UTILITY THAT OWNS AND OPERATES A WIND FACILITY.

A. I propose that the Commission require the utilities to provide a wind availability report for each wind facility that it owns and operates that will show:

A. Maximum net output of the facility given the actual wind conditions in a calendar year;

B. Lack of availability due to planned maintenance;

C. Lack of availability due to line loss;

D. Lack of availability due to forced outages, turbine failure, or non-scheduled maintenance; and,

E. Factors B, C, and D will be subtracted from A, to provide the actual capacity factor for a wind facility in a calendar year.

Q. WHY WILL THIS INFORMATION WILL BE USEFUL TO THE COMMISSION?

A. This information will provide an account of the history of the wind farm, allowing the Commission to obtain a better understanding of the different factors that affect the actual output of wind facilities. For ratemaking purposes, this information will provide an historical record that will facilitate a determination, in the future, of the appropriate methodology of calculating the capacity factor of wind farms in a test year.

<u>Issue V: What data reporting requirement should the Commission require regarding outages?</u>

Q. DO YOU PROPOSE ANY ADDITIONAL DATA REPORTING REQUIREMENTS AT THIS TIME FOR GENERATING FACILITIES OTHER THAN WIND FARMS?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

April 7, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Kelcey Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics University of Wyoming B.S. University of Wyoming Major: Business Economics Minor: Finance
EXPERIENCE:	Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric utilities. I have provided testimony in UE 199 and UE 200, and actively participated in regulatory proceedings in Oregon, including UE 195, UE 198, and UM 1355. From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support. From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development. My course work, towards a Master's degree at the University of Wyoming, focused heavily on the regulatory economics of network industries such as electricity, natural gas, and telecommunications.

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support of
Opening Testimony

April 7, 2009

VICTOR ATIYEH
GOVERNOR

PUBLIC UTILITY COMMISSIONER OF OREGON

LABOR & INDUSTRIES BUILDING, SALEM OREGON 97310 PHONE (503) 378-6053

July 31, 1984

Mr Larry A Crowley
Asst Manager-Rates
Idaho Power Company
Box 70
Boise ID 83707

Mr Grieg L Anderson
General Manager
Rates & Revenue Requirements
Portland General Electric Co
121 SW Salmon St
Portland OR 97204

Mr David W Sloan, Manager
Rates & Regulations
Pacific Power & Light Co
920 SW Sixth Ave
Portland OR 97204

AUG - 1 1984

Earlier this year, we had extensive discussions concerning the performance of several thermal plants as used in setting rates. As a result of those discussions, Tom Harris has authored the attached memorandum stating staff's position on these matters.

For rate-making, we will use historical plant data to calculate the production available from each thermal plant. In general, we will use 48 calendar months, on a rolling basis, of unit performance data. Definitions and procedures are discussed in the attached memo.

As part of our ongoing rate-making process, we will need routine reports from each utility on the performance of thermal units. The PUC staff is attempting to treat thermal plants uniformly from plant to plant and company to company. The request for specific thermal plant data is directed to each utility as listed.

Idaho Power	-Valmy 1-2
Portland General Electric	-Trojan Boardman Colstrip 3-4
Pacific Power & Light	-Jim Bridger 1-4 Dave Johnston 1-4 Wyodak Centralia 1-2 Colstrip 3-4

Data Request

For Trojan, PGE is to continue providing staff with the monthly operating data report and the semiannual net electric generation graph.

For all the other plants, within 30 days after the end of each month, each company, as listed above, is to provide the PUC staff the following data for the preceding month for each thermal unit.

- Month, Year
- Plant and Unit Name
- Maximum Dependable Capacity
- Forced Outage Hours
- Maintenance Outage Hours (Short Notice)
- Planned Outage Hours (Annual Outage)
- Reserve Shutdown Hours
- Period Hours
- Service Hours
- Equivalent Schedule Outage Hours
- Equivalent Forced Outage Hours
- Gross Generation--mwh
- Net Generation--mwh
- Planned Maintenance Schedule for Current and Subsequent Year

The above data is to be provided for the preceding month, year-to-date, preceding 12 calendar months, and 48 calendar months. Except for the last item in the list, all the other data is contained in the attached example Unit Data Summary report. Also, we wish to begin receiving the semiannual net electric generation graph for each plant as listed above for your company. In addition, you will note that performance data for Colstrip 3 depart from that used in the tracking filing. We propose using the technique suggested in Tom's memo for that facility in future rate reviews. Finally, Page 3 of Appendix A of the attached memo contains a reference to the North American Electric Reliability Council (NERC). We ask that each year each company foward the annual report from NERC containing such information immediately upon receipt.

Some additional specific questions regarding certain of the thermal plants will be transmitted in another letter.

If you have questions about this request, please contact Roger Colburn at 378-6894. Incidentally, Scott Girard has assumed responsibilities previously held by Tom Harris. His number is 378-6625.

WGWarren

William G. Warren
Manager
Energy Division

ger/05611

Attachments

cc: Roger Colburn
Scott Girard

DATE: 05/18/84

PACIFIC POWER & LIGHT COMPANY
UNIT DATA SUMMARY
PERIOD 5/ 1/83 THRU 4/30/84
WYODAK UNIT 1

FIRST SYNCHRONIZED 6/ 8/78 14:21 NAMEPLATE= 332MW DECLARED COMMERCIAL 9/18/78

		48 MONTH TOTAL		PERIOD		YEAR TO DATE		LAST MONTH	
FORCED	(HOURS/#)	712.10/	77	48.58/	3	5.28/	1	0.00/	0
MAINTENANCE	(HOURS/#)	29.95/	2	0.00/	0	0.00/	0	0.00/	0
PLANNED	(HOURS/#)	2649.38/	6	893.83/	2	0.00/	0	0.00/	0
RESERVE SHUTDOWN	(HOURS/#)	0.00/	0	0.00/	0	0.00/	0	0.00/	0
FORCED PARTIAL	(HOURS/#)	1999.37/ 2079.65	222	67.28/ 67.28	16	3.28/ 3.28	2	2.40/ 2.40	1
SCHEDULED PARTIAL	(HOURS/#)	127.12/ 127.12	16	0.00/ 0.00	0	0.00/ 0.00	0	0.00/ 0.00	0
~~NONCURTAILING EQUIPMENT~~	(HOURS/#)	64.42/	6	0.00/	0	0.00/	0	0.00/	0
PERIOD	(HOURS)	35064.00		8784.00		2904.00		720.00	
SERVICE	(HOURS)	31672.57		7841.58		2898.72		720.00	
AVAILABILITY	(HOURS)	31672.57		7841.58		2898.72		720.00	
EQUIVALENT SCHEDULED	(HOURS)	50.82		0.00		0.00		0.00	
EQUIVALENT FORCED	(HOURS)	335.70		14.58		0.56		0.45	
GROSS GENERATION	(MWH)	10230363.00		2512312.00		1044414.00		260368.00	
NET GENERATION	(MWH)	9270850.00		2283622.00		956340.00		237982.00	
MAX. DEPEND. CAP. GROSS	(MW)	345.00		345.00		345.00		345.00	
UNIT YEARS		4.00		1.00		0.33		0.08	

NOTE: EFFECTIVE SEPTEMBER 1,1977 THE UNIT MDC WAS CHANGED FROM 345 TO 345
PARTIAL OUTAGE DATA INCLUDES NONCONCURRENT (UPPER) AND CONCURRENT OUTAGE HOURS

(C: MCLAGAN,MORGAN,UDY,VINCENT,GENERATION ENGINEERING,POWER RESOURCES,THERMAL OPERATIONS

PUBLIC UTILITY COMMISSIONER OF OREGON
INTER-OFFICE CORRESPONDENCE

(NOT FOR MAILING)

DATE: July 18, 1984

TO: Bill Warren

FROM: Tom Harris

SUBJECT: Thermal Plant Performance

INTRODUCTION

In this memo I shall summarize my investigation and analysis of the performance of thermal plants for use in our rate-making process. This memo represents a "final" wrap-up of the plant performance project I began in 1983. My purpose is to develop reasonable methods for calculating thermal plant performance levels to be used for calculating the cost of power.

Performance level includes both month-to-month availability of, or net megawatts available from, each plant and the length of the expected annual maintenance period. I intend to propose a method for calculating performance that can be applied uniformly from plant to plant and from company to company. There is an exception. I shall treat Trojan a little differently because PGE collects data for Trojan to meet NRC requirements, and such data differs from that collected for coal fired plants.

In general, I propose to use a 48-calendar month rolling average of historical performance for each thermal unit on which to base cost of power calculations. The megawatts available from each thermal unit are to be calculated by (1.0 - EOR) * (MW Net) for the months during the year the unit is scheduled to be available. Definitions for Equivalent Outage Rate (EOR), MW Net, Maximum Dependable Capacity (MDC), and other terms and procedures will be discussed later in this memo. EOR is to be calculated for a 48-month period for most thermal units. The reason I propose using a 48-calendar month rolling average is that it reflects recent plant experience, which I think tends to better portray expected operation over the coming year. Four years of experience is sufficient to average out variations and yet not include generally irrelevant experience from history long past.

DEFINITIONS

The definitions and procedures I am using are intended to be similar to those adopted by the Edison Electric Institute and the North American Electric Reliability Council. The differences I propose adopting were suggested by Pacific Power & Light and by Idaho Power Company.

Following I shall list and illustrate the formula and definitions to be used.

$$MW\ available = (1.0 - EOR) * (MW\ Net)$$

$$EOR = \frac{FOH + EFOH + MOH + ESOH}{SH + FOH + MOH}$$

$$MW\ Net = MDC * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

EA - Equivalent Availability - Includes effects of EOR and planned maintenance. Essentially equivalent to the percentage of time during which the unit was available for operation at full capability.

EOR - Equivalent Outage Rate - EOR categorizes and summarizes equipment failures and their corresponding outage periods. EOR characterizes the inability of a unit to operate when required for service. It essentially is equivalent to percentage of an anticipated service, during which a unit was not available for operation at full capability. Time required for planned outages and economy or reserve shutdowns is excluded when computing this index.

EFOH - Equivalent Forced Outage Hours - For a partial forced outage reduction, EFOH is equivalent time in hours for a full forced outage which would equal mwh lost because of the partial outage.

ESOH - Equivalent Scheduled Outage Hours - For a partial scheduled outage, ESOH is equivalent time in hours for a full scheduled outage which would equal mwh lost because of the partial outage.

Scheduled and maintenance outages are scheduled a relatively short time (i.e., few days) in advance. They are distinguished from planned outages which are planned months in advance (i.e., annual outages).

- Forced Outage - The occurrence of a component failure or other conditions which requires that the unit be removed from service immediately or up to and including the very next weekend.

- Forced Partial Outage - The occurrence of a component failure or other conditions which requires that the load on the unit be reduced two percent or more immediately or up to and including the very next weekend.

FOH - Forced Outage Hours - The time in hours during which a unit is unavailable due to a forced outage.

FPOH - Forced Partial Outage Hours - The time in hours during which a unit is unavailable for full load due to a forced partial outage.

MOH - Maintenance Outage Hours - The time in hours during which a unit is unavailable due to a maintenance outage.

A maintenance outage or scheduled outage is scheduled a relatively short time (i.e., few days) in advance. For our purposes, a maintenance outage is treated like a forced outage.

PH - Period Hours - Hours in the period under consideration, usually one month, one year, or four years.

POH - Planned Outage Hours - The time in hours a unit is unavailable due to a planned outage.

Planned outages are planned months in advance. Generally these are annual maintenance outages.

POR - Partial Outage Reduction - The size of reduction from MDC in megawatts during a partial outage.

RSH - Reserve Shutdown Hours - The time in hours a unit is shutdown for economy reasons.

SH - Service Hours - The total number of hours the unit was actually operated with breakers closed to the station bus.

SPOH - Scheduled Partial Outage Hours - The time in hours during which a unit is unavailable for full load due to a scheduled partial outage. Scheduled partial outages are generally scheduled a short time in advance. For our purposes, they are treated like a forced partial outage.

mw - Megawatts

MDC - Maximum Dependable Capacity - The dependable main-unit capacity, winter or summer, whichever is smaller. MDC includes station use.

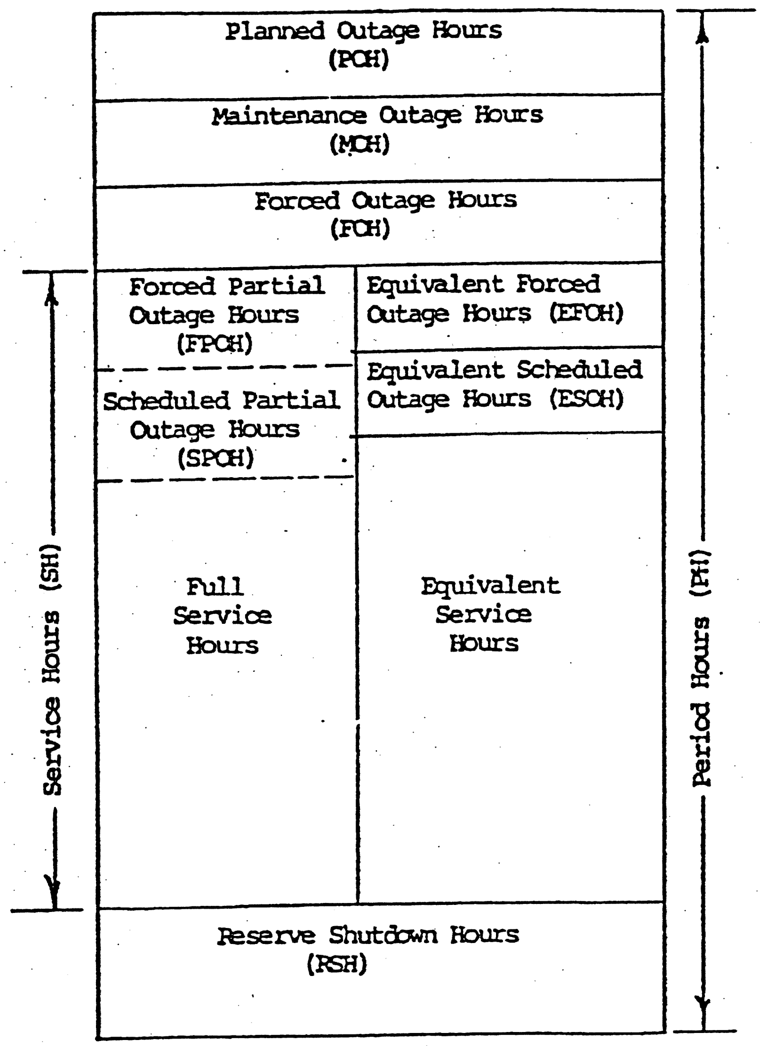
MW Net - Megawatts Net - Net megawatts available from a unit or plant excluding station use. For our purpose here:

$$\text{MW Net} = \text{MDC} * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

Figure 1 on the next page illustrates some of the above terms.

For our purposes, I have specified different definitions for and uses of the terms planned outage, maintenance outage, and scheduled outage than we have commonly used in the past. Maintenance outages or

Figure 1
Thermal Unit Availability Statistics
Definitions



scheduled outages are interchangeable terms. They both refer to unit outages which are scheduled or known a relatively short time in advance, i.e., a few days. These outages are treated like forced outages.

A planned outage is known months in advance. This outage is usually the annual maintenance shutdown. Planned outages are to be specifically used in rate-making cost of power caluclations by showing a unit as being out-of-service. Planned outages are not reflected in calculations for the Equivalent Outage Rate (EOR).

PROCEDURES

For rate-making cost of power calculations the mw available for each thermal unit are to be calculated as indiciated earlier, that is mw available = (1.0 - EOR) * (MW Net). A plant's mw available is the sum of all units' mw available. Utilities may aggregate several thermal units at one site into a plant for rate-making purposes.

The megawatts available from thermal units for rate making will generally be less than megawatts used by the utilities for Coordination Agreement purposes. The reason is the agreement permits utilities to inflate, within limits, the expected average megawatts available from the thermal plants. On average, it is to the benefit of the utilities and their ratepayers to do so. Utilities can borrow amounts of energy from the Northwest hydro system based on the firm energy resources which they report they have available. The utilities gamble that they can repay the borrowed energy from future hydro energy. In poor hydro years, they must repay energy from their thermal resources.

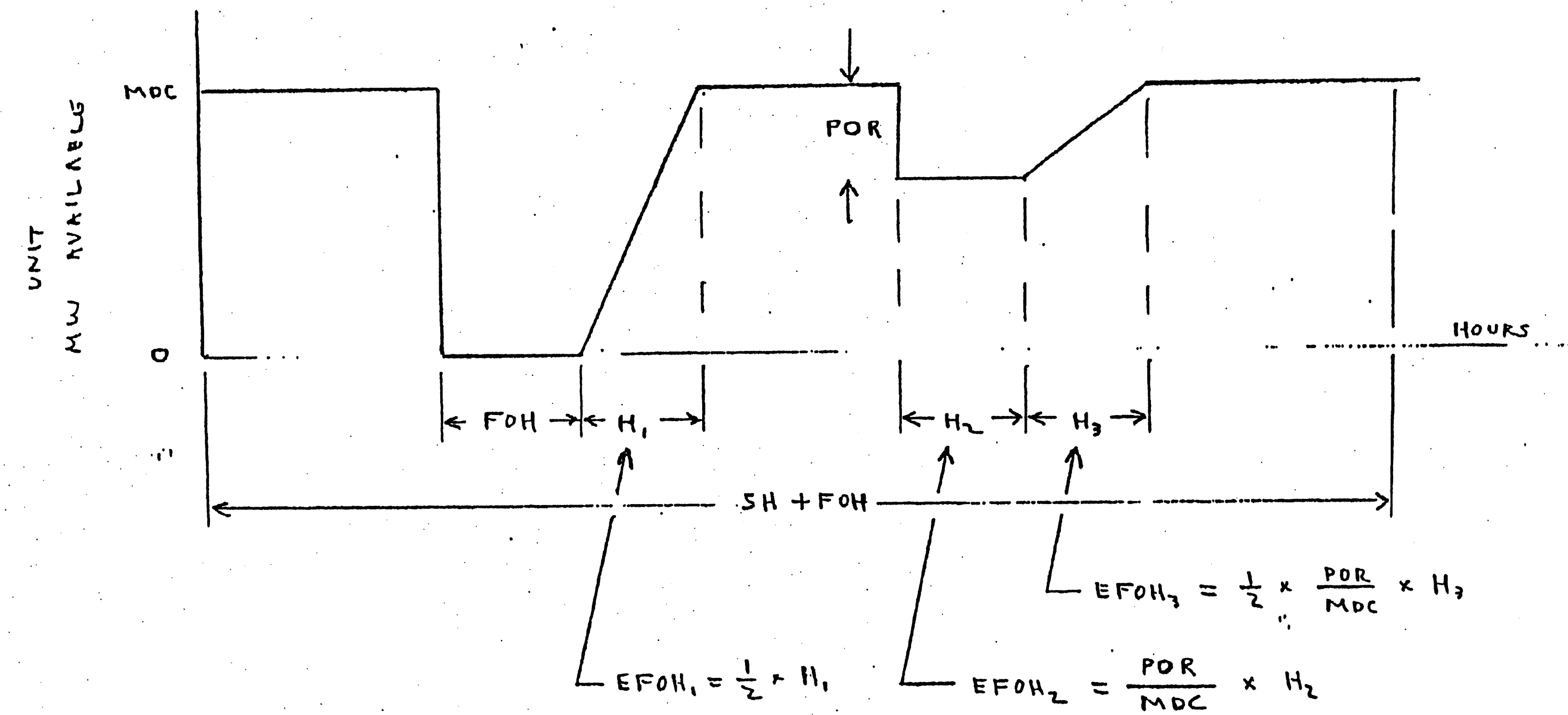
The procedures for calculating EFOH and ESOH are illustrated on the following two pages. The procedures are alike. It can be seen that EFOH and ESOH are the sum of equivalent outage hours for several partial forced or partial scheduled outages.

The EOR and MW Net are to be calculated using the most recent available 48-calendar months of performance data for each thermal unit. For thermal units with less than 48 months operation, i.e., Colstrip #3 and Valmy, the Equivalent Outage Rate to be used will be the weighted (by number of months) average of actual historical performance and national averages. The national averages I will use are shown on page 3 of Appendix "A." Those averages were compiled and published by the Thermal Resources Committee of PNUCC. The source of data is the North American Electric Reliability Council (NERC). Members of the Thermal Resources Committee include representatives of several Northwest utilities, including Portland General Electric and Pacific Power & Light. The numbers shown in the appendix are illustration only. I expect the utilities to annually furnish updated data reflecting national average performance of new thermal plants.

An example: If PGE files for a rate increase when Colstrip is two years old, PGE will have 24 months of historical data. Obviously, we will not know what the EOR for Colstrip #3 will be in its third

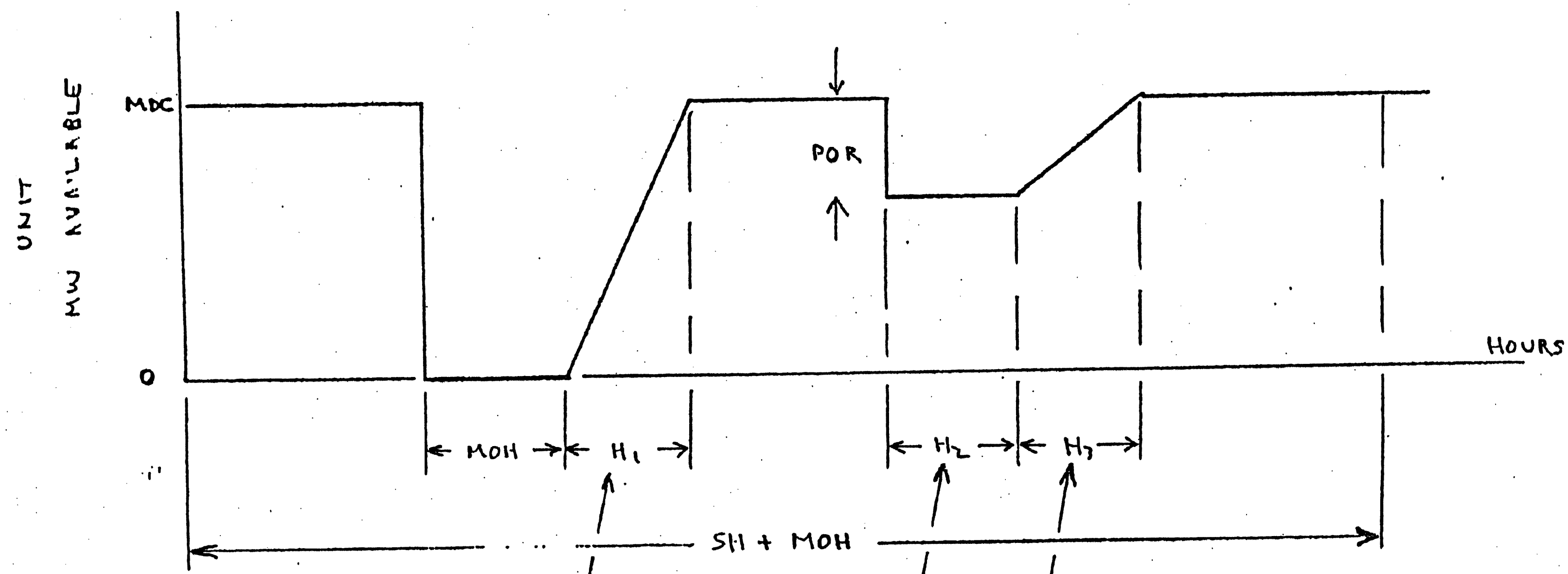
FIGURE 2

EQUIVALENT FORCED OUTAGE HOURS
ILLUSTRATION



$$EFOH = EFOH_1 + EFOH_2 + EFOH_3$$

FIGURE 3
EQUIVALENT SCHEDULED OUTAGE HOURS ILLUSTRATION



$$ESOH_1 = \frac{1}{2} \times H_1$$

$$ESOH_2 = \frac{POR}{MDC} \times H_2$$

$$ESOH_3 = \frac{1}{2} \times \frac{POR}{MDC} \times H_3$$

$$ESOH = ESOH_1 + ESOH_2 + ESOH_3$$

year. From the appendix we see the national average Forced Outage Rate for coal units of Colstrip's approximate size for the third year of operation is 12.3 percent. I shall use Forced Outage Rate, which differs slightly from EOR, for new plants because that is the data available from the PNUCC. However, we need to give some consideration to Colstrip's two years of actual operation. Let us assume the EOR for two years is actually 16.0 percent. The weighted (by number of months) average of 24 months at 16.0 percent and 12 months at 12.3 percent is 14.8 percent.

Therefore, the estimated EOR for Colstrip #3 for that coming year would be 14.8 percent. The mw available will be (1.0 - 0.148) * (700 mw) = 596.4 mw for the unit. PGE should show their 20 percent share as 119 mw for the approximate 11 months per year Colstrip #3 is scheduled to be on line.

A utility may use, for rate-making purposes, the same equivalent outage rate and planned maintenance schedule that it uses for the Coordination Agreement. I suggest that if a utility cannot provide adequate data, calculations, and workpapers to support lower performance levels (higher EOR or lower annual availability), then the PUC staff should seriously consider using Coordination Agreement values.

The MW Net calculation is to be used to reflect station use. That is, MW Net excludes station use. In power cost calculations, station use should not be a separate line item nor added to system load. I shall calculate MW Net as indicated earlier, that is:

$$\text{MW Net} = \text{MDC} * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

Portland General Electric includes in their power cost calculations a line item called non-running station service. That item is effectively a load. It is correct to use only for months a unit is planned to be off line, i.e., during planned annual maintenance. For months the unit is planned to be in service, station use is incorporated in the MW Net calculation. An alternative, which I prefer, is to have net generation mwh reflect energy used by a thermal unit when it is shutdown. In that case, non-running station service must not be specifically included in power costs.

The annual planned maintenance for rate making for each unit should be an average of a four-year cycle actual planned outages. The reason I chose a four-year average is that actual planned outages run different numbers of days from what was scheduled during the previous year. In actual practice, utilities vary from the previously scheduled outage dates in response to operating conditions.

Utilities normally expect to have relatively short planned outages for three years out of four, and a longer outage one year. The four-year average should be reflected in cost of power calculations rather than the expected planned outage during the test year for a rate case. If, over time, the actual length of planned outages varies over a five- or six-year cycle, then that should be reflected in rate making.

THERMAL PLANTS

In the following pages I shall discuss each thermal plant separately. All the data shown are calculated from data now available to me. In the coming weeks I expect Portland General Electric to provide up-to-date data for Boardman. Both Pacific Power & Light and PGE are trying to get Montana Power Company to develop and provide appropriate data for Colstrip.

The data shown below will be changed over time as more recent data is provided by the utilities. For each rate filing the utilities will need to provide updated data and, if necessary, supporting workpapers.

Portland General Electric

Trojan

MDC	1080 mw
EOR	16.4% (6/80-5/84)
Planned Maintenance	71 days
Available (Month-to-Month)	609 mw (PGE share) 23 mw (PP&L share)
Primary Utility	PGE

The EOR calculated for Trojan is for 48 months calendar June 1980-May 1984. The procedure I used was based on net mwh produced, which reflects all station use mwh and forced outages. The data comes from Trojan's monthly operating data report, which PGE prepares for the NRC and provides a copy to us. I did not calculate EOR on a month-by-month basis. I do exclude economy, planned refueling, and NRC imposed outages.

The underlying rationale for the procedure that I used is that Trojan normally is run at 100 percent of its capability. The evidence I have seen over the years points to that. There have been some clear-cut economy shutdowns, and one partial backdown for a few days for economy reasons in 1984.

The Trojan monthly operating reports show net mwh produced. The narrative part of each report discusses all outages in detail. From the narrative I determine the net hours each month Trojan should have been available by excluding refueling hours, NRC imposed shutdown hours, economy, and equivalent economy shutdown hours. I sum the net hours available and the net mwh produced over 48 months. The average mw available from Trojan is the sum of mwh divided by the sum of net hours.

For Trojan, I think the annual planned refueling and maintenance outage will vary from 61 to 80 days. The average is about 71 days. Trojan had two very long refueling outages in 1982 and 1983, which would tend to lengthen the average refueling outage. The 1982 refueling outage includes a 1-month forced outage (leaking pressurizer) which is reflected in my calculations for EOR. However, both the 1982 and 1983 refueling outages were effectively extended because of good hydro conditions and both, therefore, are partially economy shutdowns. Those long refueling outages were adjusted before the average refueling outage duration was calculated. Therefore, I believe the averge refueling outage for Trojan should be about 71 days. I developed that number in detail for my testimony in the 1983 Portland General Electric rate case, UE 1/UE 6. The average refueling outage, as adjusted, for four years, 1980 through 1983, is 71 days.

In PGE's 1983 general rate case staff settled with the company, for that case only, on a complicated method to account for Trojan's performance to be used in cost of power calculations. The company made four computer runs, for four repetitions of the test year, changing Trojan's available mw each month to show actual mw produced each month over the past four years. That method is not satisfactory. It is complicated, it entails a lot of hand calculations to average four years' results, and it does not theoretically represent Trojan's expected output over a test year. It does not account for variations in other resources. We are treating one resource, that is Trojan, philosophically different from all the other resources.

I propose we use the most recent 48 months of Trojan's historical performance to estimate available megawatts, the same as for other thermal plants. In general, regulatory (NRC) shutdowns should be excluded because they are extraordinary events. Like other thermal plants, planned maintenance and economic outages are also excluded from the calculation of megawatts available. Of course, the planned refueling outage must be represented in annual power cost calculations on an expected average basis.

Only one computer run of PGE's Power Operations Model, which is the new power cost model, is to be used to calculate the cost of power. The procedure of making four computer runs to cover four years of data is not a theoretically sound way to predict next year's cost of power, nor Trojan's performance. There are some additional power costs which result when the old power cost model is run four times using actual mw for Trojan versus one computer run using average mw for Trojan. Those additional calculated power costs will be reduced in the future because Colstrip #3 is now on line. Colstrip #3 is a low operating cost unit. Its existance will reduce variations in power cost resulting from variations in Trojan's mw output.

In PGE's 1983 general rate case, UE 1/UE 6, the difference in cost of power between four computer runs and one equivalent run was about $766,000. The one run produced the lower cost. After considering PGE's power cost adjustment, the cost to PGE is about $153,000. PGE's total cost of power is about $127,000,000. The cost to PGE from using one computer run is about 0.012 percent of their total power cost. Power cost predictions are never anywhere near that accurate, so using one computer run instead of four is well within normal accuracy limits.

I have shown an Equivalent Outage Rate (EOR) for Trojan of 16.4 percent. That translates into using 609 mw available at Trojan for PGE. Actually the 16.4 percent EOR is fiction. It reflects thousands of megawatt hours of non-running station use; however, the 609 mw itself is reasonable. PGE's power operations model includes a non-running station service as a separate line item. That line item includes non-running station service for Trojan and for Boardman. Because I exclude station service from available mw, that separate line item must be eliminated.

For Trojan, I suggest we use the average of actual historical mw produced at Trojan over the most recent rolling 48 calendar months. We will not calculate EOR as such, nor availability as a percentage. Of course, we will exclude regulatory, planned refueling, and the economy shutdowns, both full and partial, from the 48-month average.

Boardman

MDC	530 mw
EOR	14.2%
Planned Maintenance	4 weeks
Available	356 mw (PGE share)
	44 mw (IPC share)
Primary Utility	PGE

The available mw excludes station use. The EOR shown is calculated from 38 months, August 1980 through September 1983 of actual, 13.7 percent, and 10 months of national average, 16.2 percent forced outage rate. The national average data is shown on page 3 of the appendix attached to this memo. For coal plants of Boardman's size for the fourth year of operation, the average forced outage rate is 16.2 percent. In PGE's next general rate filing there will be 48 months of actual data available from Boardman, so the national average data will not be used.

The Equivalent Outage Rate that I have calculated for Boardman excludes all outages caused by the turbine blade problem. Also, it excludes planned and economy shutdowns. There are two reasons for excluding the turbine blade outages. One reason is that the problem was extraordinary. The Oregon PUC, as well as all jurisdictions, does not consider extraordinary, nonrecurring events for rate making. We set rates based on normal, ongoing expected conditions.

The second reason is that the turbine blade problem has been repaired. It was repaired in the spring of 1982. There was an additional fix made to the turbine blades in September 1983.

Colstrip #3

MDC	700 mw
EOR	17.3%
Planned Maintenance	4 weeks
Available	116 mw (PGE share)
	58 mw (PP&L share)
Primary Utility	PGE & PP&L

The EOR shown is for the first year only. It was taken from the national average data for the first year of service, which are shown on page 3 of the appendix. For the second year of operation we will calculate a weighted EOR using several months' actual data as available, and subsequent years national average forced outage rates. In addition, we will assess an appropriate planned maintenance duration, for the second and future years of operation.

Colstrip #4

MDC	700 mw
EOR	17.3%
Planned Maintenance	4 weeks
Available	116 mw (PGE share)
	58 mw (PP&L share)
Primary Utility	PGE & PP&L

The EOR shown is for the first year only. It is taken from the national average data for the first year of service, which are shown on page 3 of the appendix.

Idaho Power Company

Valmy 1

MDC	264 mw
EOR	6.96%
Planned Maintenance	4 weeks
Available	115 mw (IPC share)
Primary Utility	IPC

The EOR shown is calculated from 29 months, late December 1981 through May 1984, of actual data at 6.4 percent, seven months of third year national average data at 7.7 percent, and five months of fourth year national average data at 9.2 percent.

The actual data was taken from a Unit Data Summary report through May 1984, supplied by Idaho Power Company.

Valmy 2

MDC	264 mw
EOR	12.8%
Planned Maintenance	4 weeks
Available	115 mw (IPC share)
Primary Utility	IPC

The EOR shown is taken from the national average, for the first year of operation, for coal plants of Valmy's size.

Pacific Power & Light

The following data for four Pacific Power & Light plants is calculated from the monthly unit data summary for each unit for April 1984. The data reflects 48 months of operation for each unit through April 30, 1984. The planned maintenance shows Pacific Power's long-term cycle average for planned outage duration for each plant. The days outage duration shown are unit-days.

Jim Bridger 1-4

MDC	510 mw each (2040 mw total)
EOR	19.6%
Planned Maintenance	148 days (total 4 units)
Available	1529 mw (" " ")
	1019 mw (PP&L share, total)
	510 mw (IPC share, total)
Primary Utility	PP&L

Dave Johnston 1-4

MDC	785 mw (total 4 units)
EOR	13.0%
Planned Maintenance	113 days (total)
Available	633 mw (")
Primary Utility	PP&L

Wyodak

MDC	345 mw
EOR	3.5%
Planned Maintenance	28 days
Available	241 mw (PP&L share)
Primary Utility	PP&L

Centralia 1-2

MDC	665 mw each (1330 mw total)
EOR	13.1%
Planned Maintenance	74 days (total 2 units)
Available	522 mw (PP&L share, total)
	27 mw (PGE share, total)
Primary Utility	PP&L

The above data for each MDC rating reflects the data available to me now. For each rate filing the utilities will need to provide up-to-date information and, if necessary, supporting documents.

PLANNED AND ECONOMY OUTAGES

The EOR indicated for the above thermal plants was calculated excluding planned and economy outages. Where data was available, the EOR was calculated as a 48-calendar month average. For rate making, cost of power calculations will use (1.0 - EOR) * (MW Net) as the unit or plant megawatts available for the several months each year the unit is scheduled to be on line. In addition, the cost of power calculations need to reflect planned maintenance outages for each unit or plant.

For the coal plants listed earlier, annual planned maintenance varies from three to six weeks. I prefer that utilities use a long-run cycle average for planned outage duration for rate making. As an alternative, the above estimates of annual planned maintenance may be altered annually by the utilities with staff's concurrence to reflect the expected maintenance schedule for the test period used in a rate case.

The procedure I propose excludes reserve shutdown (economy outages) and planned maintenance outages from the calculation of Equivalent Outage Rate (EOR). Economy and planned outages do not count for nor against utilities. If we use this procedure, then the theoretical problem of considering a unit as 100 percent available during a reserve shutdown does not exist. PGE and PP&L have argued that a plant should not be considered 100 percent available when it is not running, because if it were operated there would be, on average, some forced outages. Their's is a reasonable argument.

Occasionally we will need to determine if an outage was a forced or a reserve (economy) shutdown. The outage will be considered a reserve (economy) shutdown unless the utility provides a clear, definite explanation of the cause.

GENERAL INFORMATION

The only thermal plants of concern in this memo are those discussed earlier. Some data about each plant is also listed in the attached appendix. Beaver and other combustion turbines and diesel units are not covered by this memo because their maximum performance, or maximum available mw, have not been serious issues in rate making.

I do not suggest the PUC accept "carte blanche" whatever Equivalent Outage Rate (EOR) or MW Net the utilities calculate for each unit, even if such actually occurred. As in all aspects of rate making, if we can reasonably establish that substandard performance was due to poor or imprudent management then we can and should disallow some cost or adjust the historical EOR or MW Net. That applies even to data I have shown earlier.

The list of thermal plants discussed earlier and also shown in the appendix indicates the primary utility, i.e., Portland General Electric, Idaho Power Company, or Pacific Power & Light. The primary utility is the one the PUC staff generally will expect to furnish data for the unit and to estimate planned maintenance outages. However, if the primary utility does not furnish appropriate data, the other involved utilities will not be excused.

An exception is Colstrip. There, for the time being, I propose to treat PGE and PP&L as each being responsible to develop the relevent data; however, they need not act independently. I suggest that each act as a check on each other and on Montana Power.

Usually the procedures, data, and results we settle on for the primary utility will be applied to the other utilities for each plant. I am sure there will be exceptions over the years.

bjs/1710m

Attachments

Thermal Plant Performance

Plant	48 Months EOR[1]	48 Months Thru
Trojan	16.4%	5/84
Boardman	14.2	9/83[2]
Colstrip 3	17.3[3]	As of on-line date (1/10/84)
Colstrip 4	17.3	As of on-line date
Valmy 1	7.9	7/83[2]
Valmy 2	12.8	As of on-line date
Bridger 1-4	19.6	4/84
D. Johnston	13.0	"
Wyodak	3.5	"
Centralia 1-2	13.1	"

[1]EOR in percent

[2]EOR includes actual and additional one year from national averages.

[3]National average data. For illustration only until actual performance data is available.

jcp/1014j-1

Appendix A
Pg. 2

Thermal Plants

Plant	MDC mw[1]	Primary Utility[2]	Percent Share	Other Utility	Percent Share
Trojan	1080 mw	PGE	67.5%	PP&L	2.5%
Boardman	530	PGE	80.0	IPC	10.0
Colstrip 3	700	PGE	20.0	PP&L[3]	10.0
Colstrip 4	700	PGE	20.0	PP&L[3]	10.0
Valmy 1	254	IPC	50.0		
Valmy 2	254	IPC	50.0		
Bridger 1-4	510 each	PP&L	66.7	IPC	33.3
D Johnston	785 total	PP&L	100.0		
Wyodak	345	PP&L	80.0		
Centralia 1-2	665 each	PP&L	47.5	PGE	2.5

[1]Nameplate rating.

[2]Primary utility for providing data and planned maintenance schedules for Oregon rate making.

[3]For Colstrip PP&L will also be treated as the primary utility.

jcp/1014j-2

Thermal Plants

First four years of service. Values to be averaged with actual performance for plants less than four years old.

Plant	Nameplate MW	Year of Service[1] 1st FOR[2]	2nd FOR	3rd FOR	4th FOR
Boardman[3]	530				16.2
Colstrip 3 & 4	700 ea	17.3	14.7	12.3	15.7
Valmy 1 & 2	254 ea	12.8	6.4	7.7	9.2

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[1]Data: FOR in percent. National figures.
Source: PNUCC Thermal Resources Data Base Addendum February 1, 1983.
PNUCC source is North American Electric Reliability Council (NERC).

[2]EOR, Forced Outage Rate

[3]It is expected 48 months data for Boardman will be available before PGE's next rate filing.

jcp/1014j-3

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support of
Opening Testimony

April 7, 2009

PacifiCorp Coal Fired Units 2005-2008
Staff Data Request #5

	Data	
Unit ID	Sum of Non-Forced hours during Low Load Period*	Sum of Non-Forced hours during High Load Period*
CHO-4	54	37
COL-3	270	224
COL-4	304	227
CRB-1	494	265
CRB-2	772	527
CRG-1	0	0
CRG-2	42	19
DJ-1	25	40
DJ-2	60	59
DJ-3	22	5
DJ-4	211	231
HDN-1	179	266
HDN-2	171	236
HTG-1	1,419	1,332
HTG-2	1,039	787
HTR-1	1,179	1,146
HTR-2	1,653	1,500
HTR-3	1,448	1,361
JB-1	553	443
JB-2	471	194
JB-3	571	275
JB-4	412	290
NTN-1	1,464	708
NTN-2	1,692	814
NTN-3	1,439	933
WYO-1	515	476
Grand Total	16,458	12,396

Total Hours for all Coal plants		**28,854**
	% Low Load Hours	**% High Low Hours**
	57%	**43%**

*Non forced activity is defined as: Maint. Outages, maint. Extensions, planned derates, & maint. Derates.

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support of
Opening Testimony

April 7, 2009

Forecast Trending Analysis

1,413 MW Plant Capacity

Jim Bridger	Grand Total Hours	Forecast Naive	Naive % error	Forecast 2 year rolling avg	2 year % error	Forecast 3 year rolling avg.	3 year % error	Forecast 4 year rolling avg	4 year % error	Forecast 5 year rolling avg	5 year % error	Forecast 6 year rolling avg	6 year % error	Forecast 4 year weighted avg	% error	Weights
1979	3,535,641															0.10
1980	3,803,416															0.20
1981	4,193,370	3,535,641	-16%													0.30
1982	2,035,950	3,803,416	87%	3,669,529	80%											0.40
1983	1,708,626	4,193,370	145%	3,998,393	134%	3,844,142	125%									
1984	1,194,910	2,035,950	70%	3,114,660	161%	3,344,245	180%	3,392,094	184%					3,186,638	167%	
1985	1,475,704	1,708,626	16%	1,872,288	27%	2,645,982	79%	2,935,340	99%	3,055,401	107%			2,513,251	70%	
1986	895,198	1,194,910	33%	1,451,768	62%	1,646,495	84%	2,283,214	155%	2,587,254	189%	2,745,319	207%	1,817,079	103%	
1987	1,445,958	1,475,704	2%	1,335,307	-8%	1,459,747	1%	1,603,797	11%	2,121,712	47%	2,401,996	66%	1,494,075	3%	
1988	1,451,022	895,198	-38%	1,185,451	-18%	1,188,604	-18%	1,318,609	-9%	1,462,077	1%	1,917,293	32%	1,210,635	-17%	
1989	1,587,080	1,445,958	-9%	1,170,578	-26%	1,272,286	-20%	1,252,942	-21%	1,344,079	-15%	1,459,391	-8%	1,261,574	-21%	
1990	1,018,309	1,451,022	42%	1,448,490	42%	1,264,059	24%	1,316,970	29%	1,292,558	27%	1,361,903	34%	1,340,806	32%	
1991	1,625,987	1,587,080	-2%	1,519,051	-7%	1,494,687	-8%	1,344,814	-17%	1,370,992	-16%	1,341,645	-17%	1,448,850	-11%	
1992	1,130,155	1,018,309	-10%	1,302,695	15%	1,352,137	20%	1,375,592	22%	1,279,513	13%	1,312,212	16%	1,318,248	17%	
1993	1,502,964	1,625,987	8%	1,322,148	-12%	1,410,459	-6%	1,420,599	-5%	1,425,671	-5%	1,337,259	-11%	1,418,406	-6%	
1994	1,176,344	1,130,155	-4%	1,378,071	17%	1,258,150	7%	1,340,383	14%	1,362,511	16%	1,376,418	17%	1,302,228	11%	
1995	1,146,936	1,502,964	31%	1,316,559	15%	1,419,702	24%	1,319,354	15%	1,372,899	20%	1,385,919	21%	1,367,260	19%	
1996	1,503,327	1,176,344	-22%	1,339,654	-11%	1,269,821	-16%	1,358,862	-10%	1,290,752	-14%	1,340,140	-11%	1,310,056	-13%	
1997	1,466,967	1,146,936	-22%	1,161,640	-21%	1,275,415	-13%	1,239,100	-16%	1,316,477	-10%	1,266,782	-14%	1,225,286	-16%	
1998	1,247,506	1,503,327	21%	1,325,132	6%	1,275,536	2%	1,332,393	7%	1,291,945	4%	1,347,619	8%	1,330,977	7%	
1999	1,532,776	1,466,967	-4%	1,485,147	-3%	1,372,410	-10%	1,323,394	-14%	1,359,308	-11%	1,321,116	-14%	1,384,807	-10%	
2000	1,221,417	1,247,506	2%	1,357,237	11%	1,405,934	15%	1,341,184	10%	1,308,216	7%	1,340,674	10%	1,354,452	11%	
2001	1,275,547	1,532,776	20%	1,390,141	9%	1,415,750	11%	1,437,644	13%	1,379,503	8%	1,345,643	5%	1,431,088	12%	
2002	2,374,348	1,221,417	-49%	1,377,097	-42%	1,333,900	-44%	1,367,167	-42%	1,394,399	-41%	1,353,155	-43%	1,344,598	-43%	
2003	2,746,759	1,275,547	-54%	1,248,482	-55%	1,343,247	-51%	1,319,312	-52%	1,348,843	-51%	1,374,590	-50%	1,307,950	-52%	
2004	2,450,159	2,374,348	-3%	1,824,948	-26%	1,623,771	-34%	1,601,022	-35%	1,530,319	-38%	1,519,760	-38%	1,729,964	-29%	
2005	2,534,334	2,746,759	8%	2,560,554	1%	2,132,218	-16%	1,904,518	-25%	1,830,170	-28%	1,733,059	-32%	2,188,259	-14%	
2006	2,059,330	2,450,159	19%	2,598,459	26%	2,523,755	23%	2,211,703	7%	2,013,646	-2%	1,933,501	-6%	2,406,516	17%	
2007	2,110,135	2,534,334	20%	2,492,246	18%	2,577,084	22%	2,526,400	20%	2,276,229	8%	2,100,427	0%	2,535,568	20%	
Average	1,607,751	1,825,211	11%	1,778,682	15%	1,725,981	15%	1,661,100	14%	1,609,325	9%	1,573,446	8%	1,634,524	11%	
Maximum Value	2,746,759	2,746,759	42%	2,598,459	62%	2,645,982	84%	2,935,340	155%	3,055,401	189%	2,745,319	207%	2,535,568	103%	
Minimum Value	895,198	895,198	-54%	1,161,640	-55%	1,188,604	-51%	1,239,100	-52%	1,279,513	-51%	1,266,782	-50%	1,210,635	-52%	
Median error		1,502,964	2%	1,384,106	8%	1,410,459	2%	1,363,014	7%	1,372,899	1%	1,368,247	-3%	1,376,034	5%	
Standard Deviation		871,579	41%	793,414	49%	710,535	52%	583,598	56%	480,993	51%	401,219	52%	530,125	47%	

Forecast Trending Analysis

172 MW		Plant Capacity														
Carbon	Grand Total Hours	Forecast Naïve	Naïve % error	Forecast 2 year rolling avg	2 year % error	Forecast 3 year rolling avg.	3 year % error	Forecast 4 year rolling avg	4 year % error	Forecast 5 year rolling avg	5 year % error	Forecast 6 year rolling avg	6 year % error	Forecast 4 year weighted avg	% error	Weights
1979	79,533															0.10
1980	156,189															0.20
1981	51,422	79,533	55%													0.30
1982	250,634	156,189	-38%	117,861	-53%											0.40
1983	73,197	51,422	-30%	103,805	42%	95,715	31%									
1984	74,134	250,634	238%	151,028	104%	152,748	106%	134,444	81%					154,871	109%	
1985	119,380	73,197	-39%	161,915	36%	125,084	5%	132,860	11%	122,195	2%			130,372	9%	
1986	110,611	74,134	-33%	73,665	-33%	132,655	20%	112,347	2%	121,115	9%	114,185	3%	106,882	-3%	
1987	54,834	119,380	118%	96,757	76%	88,904	62%	129,336	136%	113,753	107%	120,826	120%	109,695	100%	
1988	52,993	110,611	109%	114,996	117%	101,375	91%	94,331	78%	125,591	137%	113,230	114%	102,205	93%	
1989	55,093	54,834	0%	82,723	50%	94,942	72%	89,740	63%	86,431	57%	113,798	107%	86,407	57%	
1990	70,414	52,993	-25%	53,914	-23%	72,813	3%	84,455	20%	82,391	17%	80,858	15%	71,708	2%	
1991	39,519	55,093	39%	54,043	37%	54,307	37%	68,383	73%	78,583	99%	77,841	97%	59,963	52%	
1992	21,893	70,414	222%	62,754	187%	59,500	172%	58,334	166%	68,789	214%	77,221	253%	60,776	178%	
1993	73,221	39,519	-46%	54,967	-25%	55,009	-25%	54,505	-26%	54,571	-25%	63,911	-13%	53,250	-27%	
1994	61,731	21,893	-65%	30,706	-50%	43,942	-29%	46,730	-24%	47,983	-22%	49,124	-20%	40,205	-35%	
1995	47,387	73,221	55%	47,557	0%	44,878	-5%	51,262	8%	52,028	10%	52,189	10%	50,801	7%	
1996	74,698	61,731	-17%	67,476	-10%	52,281	-30%	49,091	-34%	53,355	-29%	53,645	-28%	54,989	-26%	
1997	109,938	47,387	-57%	54,559	-50%	60,780	-45%	51,058	-54%	48,750	-56%	52,361	-52%	54,308	-51%	
1998	175,943	74,698	-58%	61,043	-65%	61,272	-65%	64,259	-63%	55,786	-68%	53,075	-70%	63,764	-64%	
1999	137,649	109,938	-20%	92,318	-33%	77,341	-44%	73,439	-47%	73,395	-47%	64,811	-53%	82,035	-40%	
2000	47,060	175,943	274%	142,941	204%	120,193	155%	101,992	117%	93,939	100%	90,486	92%	123,037	161%	
2001	59,080	137,649	133%	156,796	165%	141,177	139%	124,557	111%	109,123	85%	101,224	71%	137,300	132%	
2002	92,034	47,060	-49%	92,355	0%	120,217	31%	117,648	28%	109,058	18%	98,779	7%	106,301	16%	
2003	75,204	59,080	-21%	53,070	-29%	81,263	8%	104,933	40%	105,934	41%	100,728	34%	82,874	10%	
2004	85,858	92,034	7%	75,557	-12%	66,058	-23%	83,956	-2%	102,353	19%	103,618	21%	77,715	-9%	
2005	80,986	75,204	-7%	83,619	3%	75,440	-7%	68,345	-16%	82,206	2%	97,829	21%	74,214	-8%	
2006	91,222	85,858	-6%	80,531	-12%	84,366	-8%	78,044	-14%	71,847	-21%	82,814	-9%	81,219	-11%	
2007	111,493	80,986	-27%	83,422	-25%	80,683	-28%	83,521	-25%	78,633	-29%	73,371	-34%	82,396	-26%	
Average	80,358	86,320	26%	86,553	23%	85,718	25%	85,732	26%	84,253	27%	83,451	31%	85,304	26%	
Maximum Value	175,943	175,943	274%	161,915	204%	141,177	172%	132,860	166%	125,591	214%	120,826	253%	137,300	178%	
Minimum Value	21,893	21,893	-65%	30,706	-65%	43,942	-65%	46,730	-63%	47,983	-68%	49,124	-70%	40,205	-64%	
Median error		74,134	-17%	81,627	-5%	80,683	5%	83,738	10%	82,206	10%	81,836	12%	81,627	5%	
Standard Deviation		48,413	95%	35,805	76%	31,148	65%	28,527	64%	25,540	69%	23,404	76%	30,240	68%	

Staff/104
Brown/2

Forecast Trending Analysis

0
0
0

762 MW Plant Capacity

Dave Johnston	Grand Total Hours	Forecast Naïve	Naïve % error	Forecast 2 year rolling avg	2 year % error	Forecast 3 year rolling avg.	3 year % error	Forecast 4 year rolling avg	4 year % error	Forecast 5 year rolling avg	5 year % error	Forecast 6 year rolling avg	6 year % error	Forecast 4 year weighted avg	% error	Weights
1979	698,264															0.10
1980	626,376															0.20
1981	872,867	698,264	-20%													0.30
1982	660,891	626,376	-5%	662,320	0%											0.40
1983	536,000	872,867	63%	749,622	40%	732,503	37%									
1984	839,288	660,891	-21%	766,879	-9%	720,045	-14%	714,600	-15%					721,318	-14%	
1985	741,319	536,000	-28%	598,445	-19%	689,919	-7%	674,033	-9%	678,880	-8%			649,878	-12%	
1986	343,544	839,288	144%	687,644	100%	678,726	98%	727,261	112%	707,084	106%	705,614	105%	715,980	108%	
1987	341,688	741,319	117%	790,303	131%	705,536	106%	694,374	103%	730,073	114%	712,790	109%	721,603	111%	
1988	494,233	343,544	-30%	542,431	10%	641,384	30%	615,038	24%	624,208	26%	665,651	35%	581,271	18%	
1989	604,079	341,688	-43%	342,616	-43%	475,517	-21%	566,460	-6%	560,368	-7%	577,121	-4%	471,931	-22%	
1990	360,947	494,233	37%	417,960	16%	393,155	9%	480,196	33%	552,014	53%	549,345	52%	443,040	23%	
1991	376,269	604,079	61%	549,156	46%	480,000	28%	445,886	19%	504,972	34%	560,692	49%	492,593	31%	
1992	330,250	360,947	9%	482,513	46%	486,419	47%	450,236	36%	428,898	30%	480,968	46%	458,618	39%	
1993	324,386	376,269	16%	368,608	14%	447,098	38%	458,882	41%	435,443	34%	420,127	30%	429,031	32%	
1994	321,660	330,250	3%	353,260	10%	355,822	11%	417,886	30%	433,156	35%	417,911	30%	377,578	17%	
1995	479,443	324,386	-32%	327,318	-32%	343,635	-28%	347,963	-27%	399,186	-17%	415,027	-13%	340,178	-29%	
1996	741,405	321,660	-57%	323,023	-56%	325,432	-56%	338,141	-54%	342,702	-54%	386,265	-48%	329,657	-56%	
1997	553,959	479,443	-13%	400,552	-28%	375,163	-32%	363,935	-34%	366,402	-34%	365,493	-34%	386,178	-30%	
1998	710,365	741,405	4%	610,424	-14%	514,170	-28%	466,724	-34%	439,429	-38%	428,902	-40%	537,166	-24%	
1999	813,348	553,959	-32%	647,682	-20%	591,602	-27%	524,117	-36%	484,171	-40%	458,517	-44%	572,060	-30%	
2000	857,930	710,365	-17%	632,162	-26%	668,576	-22%	621,293	-28%	561,367	-35%	521,870	-39%	646,559	-25%	
2001	648,287	813,348	25%	761,857	18%	692,557	7%	704,769	9%	659,704	2%	603,363	-7%	723,381	12%	
2002	678,612	857,930	26%	835,639	23%	793,881	17%	733,900	8%	735,401	8%	692,742	2%	784,645	16%	
2003	687,396	648,287	-6%	753,108	10%	773,188	12%	757,483	10%	716,778	4%	720,882	5%	750,400	9%	
2004	592,996	678,612	14%	663,449	12%	728,276	23%	749,544	26%	741,708	25%	710,417	20%	718,851	21%	
2005	409,575	687,396	68%	683,004	67%	671,431	64%	718,056	75%	737,114	80%	732,656	79%	693,992	69%	
2006	684,995	592,996	-13%	640,196	-7%	653,001	-5%	651,823	-5%	693,044	1%	713,095	4%	643,968	-6%	
2007	660,689	409,575	-38%	501,286	-24%	563,322	-15%	592,145	-10%	603,373	-9%	645,799	-2%	547,069	-17%	
Average	554,668	579,458	9%	580,441	10%	580,014	11%	575,614	11%	571,108	13%	567,511	15%	572,373	10%	
Maximum Value	857,930	857,930	144%	835,639	131%	793,881	106%	757,483	112%	741,708	114%	732,656	109%	784,645	111%	
Minimum Value	321,660	321,660	-57%	323,023	-56%	325,432	-56%	338,141	-54%	342,702	-54%	365,493	-48%	329,657	-56%	
Median error		604,079	-5%	621,293	10%	641,384	9%	603,591	8%	561,367	4%	568,907	4%	576,665	10%	
Standard Deviation		180,692	48%	160,411	43%	147,671	40%	139,713	42%	134,496	45%	128,632	45%	143,191	42%	

Forecast Trending Analysis

1,123 MW Plant Capacity

Hunter	Grand Total Hours	Forecast Naive	Naive % error	Forecast 2 year rolling avg	2 year % error	Forecast 3 year rolling avg.	3 year % error	Forecast 4 year rolling avg	4 year % error	Forecast 5 year rolling avg	5 year % error	Forecast 6 year rolling avg	6 year % error	Forecast 4 year weighted avg	% error	Weights
1979	193,925															0.10
1980	377,527															0.20
1981	417,805	193,925	-54%													0.30
1982	553,434	377,527	-32%	285,726	-48%											0.40
1983	1,232,936	417,805	-66%	397,666	-68%	329,752	-73%									
1984	559,322	553,434	-1%	485,620	-13%	449,589	-20%	385,673	-31%					441,613	-21%	
1985	433,049	1,232,936	185%	893,185	106%	734,725	70%	645,425	49%	555,125	28%			780,518	80%	
1986	1,754,306	559,322	-68%	896,129	-49%	781,897	-55%	690,874	-61%	628,205	-64%	555,825	-68%	746,077	-57%	
1987	639,766	433,049	-32%	496,185	-22%	741,769	16%	694,685	9%	639,309	0%	595,679	-7%	642,947	0%	
1988	863,099	1,754,306	103%	1,093,677	27%	915,559	6%	994,903	15%	906,609	5%	825,142	-4%	1,066,795	24%	
1989	1,001,534	639,766	-36%	1,197,036	20%	942,374	-6%	846,611	-15%	923,876	-8%	862,135	-14%	924,740	-8%	
1990	765,911	863,099	13%	751,433	-2%	1,085,724	42%	922,555	20%	849,908	11%	913,746	19%	931,336	22%	
1991	777,519	1,001,534	29%	932,316	20%	834,800	7%	1,064,676	37%	938,351	21%	875,179	13%	962,927	24%	
1992	1,129,200	765,911	-32%	883,722	-22%	876,848	-22%	817,578	-28%	1,004,923	-11%	909,611	-19%	843,421	-25%	
1993	437,049	777,519	78%	771,715	77%	848,321	94%	852,016	95%	809,566	85%	967,022	121%	827,397	89%	
1994	669,055	1,129,200	69%	953,359	42%	890,877	33%	918,541	37%	907,453	36%	862,838	29%	938,271	40%	
1995	333,681	437,049	31%	783,124	135%	781,256	134%	777,420	133%	822,242	146%	829,052	148%	745,674	123%	
1996	585,867	669,055	14%	553,052	-6%	745,101	27%	753,206	29%	755,747	29%	796,711	36%	702,328	20%	
1997	1,046,044	333,681	-68%	501,368	-52%	479,928	-54%	642,246	-39%	669,301	-36%	685,402	-34%	534,518	-49%	
1998	933,964	585,867	-37%	459,774	-51%	529,534	-43%	506,413	-46%	630,970	-32%	655,395	-30%	511,967	-45%	
1999	1,252,890	1,046,044	-17%	815,956	-35%	655,197	-48%	658,662	-47%	614,339	-51%	700,149	-44%	727,819	-42%	
2000	1,688,883	933,964	-45%	990,004	-41%	855,292	-49%	724,889	-57%	713,722	-58%	667,610	-60%	837,940	-50%	
2001	2,562,500	1,252,890	-51%	1,093,427	-57%	1,077,633	-58%	954,691	-63%	830,489	-68%	803,583	-69%	1,049,141	-59%	
2002	980,210	1,688,883	72%	1,470,887	50%	1,291,913	32%	1,230,445	26%	1,101,530	12%	973,555	-1%	1,342,818	37%	
2003	1,300,685	2,562,500	97%	2,125,692	63%	1,834,758	41%	1,609,559	24%	1,496,856	15%	1,345,025	3%	1,875,639	44%	
2004	1,177,356	980,210	-17%	1,771,355	50%	1,743,864	48%	1,621,121	38%	1,483,689	26%	1,410,749	20%	1,623,899	38%	
2005	1,168,728	1,300,685	11%	1,140,447	-2%	1,614,465	38%	1,633,069	40%	1,557,034	33%	1,453,189	24%	1,495,725	28%	
2006	962,304	1,177,356	22%	1,239,020	29%	1,152,750	20%	1,505,187	56%	1,541,927	60%	1,493,754	55%	1,313,440	36%	
2007	961,772	1,168,728	22%	1,173,042	22%	1,215,590	26%	1,156,745	20%	1,437,896	50%	1,479,727	54%	1,178,856	23%	
Average	1,018,494	919,861	7%	929,035	7%	936,381	8%	941,966	10%	948,655	10%	939,140	8%	960,242	11%	
Maximum Value	2,562,500	2,562,500	185%	2,125,692	135%	1,834,758	134%	1,633,069	133%	1,557,034	146%	1,493,754	148%	1,875,639	123%	
Minimum Value	333,681	333,681	-68%	459,774	-57%	479,928	-58%	506,413	-63%	555,125	-68%	555,825	-69%	511,967	-59%	
Median error		863,099	-1%	894,657	-2%	855,292	16%	849,313	20%	849,908	12%	862,487	1%	884,081	22%	
Standard Deviation		518,490	62%	423,562	53%	379,914	52%	353,489	50%	328,522	50%	298,805	55%	358,058	49%	

CASE: UM 1355
WITNESS: KELCEY BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support of
Opening Testimony

April 7, 2009

Coal Fossil Units 600-699MW
NERC Data

Units	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	0.69	0.91	0.01	0.00	0.42	0.19	0.10	0.22	0.07
2	1.06	1.00	0.33	0.09	0.50	0.38	0.46	0.47	0.18
3	1.33	1.62	0.60	0.54	0.63	0.96	0.84	0.60	0.21
4	1.81	1.67	0.88	0.63	0.75	1.01	0.88	0.62	0.24
5	1.91	1.70	0.99	0.64	1.32	1.21	1.14	0.71	0.99
6	1.94	1.77	1.00	0.70	1.35	1.23	1.30	1.27	1.04
7	1.97	2.00	1.14	0.72	1.36	1.42	1.60	1.33	1.22
8	2.42	2.04	1.21	0.79	1.42	1.48	1.69	1.40	1.25
9	2.46	2.10	1.26	0.83	1.54	1.59	1.81	1.64	1.50
10	2.49	2.15	1.40	0.92	1.59	1.67	2.03	1.91	1.95
11	2.57	2.50	1.90	0.94	1.60	1.93	2.07	1.94	2.00
12	2.77	2.53	1.92	0.98	1.70	1.97	2.39	2.03	2.05
13	2.92	2.54	2.04	1.12	1.78	2.06	2.46	2.06	2.17
14	2.99	2.60	2.15	1.21	1.79	2.26	2.51	2.41	2.41
15	3.11	2.68	2.19	1.30	1.83	2.40	2.62	2.58	2.61
16	3.12	2.81	2.37	1.37	1.91	2.57	2.85	2.94	2.99
17	3.22	3.03	2.56	1.42	2.08	2.58	2.94	2.98	3.29
18	3.25	3.06	3.25	1.55	2.29	2.70	3.00	3.06	3.40
19	3.47	4.18	3.35	1.59	2.53	2.97	3.05	3.24	3.46
20	3.71	4.22	3.84	1.64	2.75	3.14	3.38	3.33	3.75
21	3.89	4.34	3.93	1.72	3.18	3.34	3.63	3.48	3.79
22	4.01	4.51	4.33	1.86	3.35	3.36	4.03	3.87	3.86
23	4.02	4.80	4.50	1.89	3.91	3.45	4.12	4.20	4.21
24	4.26	4.89	4.60	1.99	3.97	3.67	4.33	4.40	4.71
25	4.37	5.00	4.62	2.70	4.42	3.71	4.34	4.47	5.04
26	4.56	5.05	4.68	2.79	4.50	3.80	4.88	4.62	5.11
27	4.95	5.14	4.78	2.99	5.02	3.84	4.90	4.65	5.21
28	4.98	5.32	4.90	3.10	5.22	4.06	5.11	4.71	5.45
29	5.23	5.67	5.12	3.17	5.30	4.59	5.12	4.97	5.52
30	5.33	5.68	5.47	3.41	5.52	4.67	5.25	5.15	5.55
31	5.56	6.02	5.58	3.50	5.83	4.71	5.42	5.26	5.67
32	5.78	6.14	5.87	3.77	5.87	4.98	5.45	5.40	5.68
33	5.94	6.23	5.98	3.84	5.89	5.07	5.73	5.60	5.80
34	5.95	6.29	6.18	4.17	6.02	5.09	5.82	5.92	6.21
35	6.37	6.37	6.90	4.42	6.05	5.14	5.95	5.93	6.40
36	6.82	6.69	7.31	4.44	6.07	5.25	5.96	6.30	6.98
37	7.10	7.00	7.44	4.52	6.49	5.29	6.50	6.50	7.61
38	7.36	7.10	7.62	4.61	6.78	5.63	6.62	6.52	8.00
39	7.54	7.11	7.69	4.76	7.03	5.68	6.64	6.76	8.57
40	7.86	7.27	7.83	4.90	7.18	5.90	7.24	6.87	8.62
41	8.46	7.40	7.87	5.51	7.47	6.46	7.45	6.91	8.90
42	8.48	8.68	7.90	5.63	7.79	6.62	7.66	7.05	9.37
43	8.92	8.97	7.91	5.68	8.08	6.95	7.73	7.07	9.53
44	9.08	9.31	8.04	6.07	8.12	7.24	7.96	7.46	9.69
45	9.57	9.97	8.70	6.73	8.78	7.76	8.00	10.26	10.08
46	10.17	10.39	9.57	7.37	9.37	7.91	8.34	10.58	10.36
47	10.57	10.86	10.68	8.02	10.80	8.05	8.65	10.88	10.37
48	10.68	11.20	11.51	8.35	10.83	8.41	9.64	11.35	10.45
49	11.17	11.66	12.03	9.42	11.23	8.52	10.40	12.36	10.77
50	11.51	12.13	14.02	10.51	13.15	10.42	10.60	12.45	11.45
51	13.17	14.05	18.34	10.71	13.92	10.88	11.65	17.18	11.83
52	13.78	14.38		17.06	16.55	12.02	11.74	22.40	13.93
53	13.97	14.48		17.74	22.11	12.52	22.60	23.23	14.20
54	14.22	17.86		34.51	23.34	12.70	29.51	23.72	14.47
55	16.71	23.00				13.55		24.93	17.54
56	19.24	36.55				14.93			23.25
57	20.55					16.37			23.85
58						30.94			
90th percentile	13.41	13.09	9.57	9.10	11.11	12.17	10.17	12.41	12.67
10th percentile	1.96	1.89	1.00	0.71	1.35	1.36	1.39	1.29	1.15

4 year average 90th percentile	11.29	10.72	10.49	10.64	11.47	11.86
4 year average 10th percentile	1.39	1.24	1.11	1.20	1.35	1.30

Coal Fossil Units 500-599MW
NERC Data

Units	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	0.18	0.00	0.04	0.00	0.47	0.34	0.60	0.33	0.15
2	0.50	0.13	0.13	0.45	0.53	0.44	0.71	0.35	0.29
3	0.55	0.28	0.19	0.55	0.67	0.48	1.36	0.71	0.74
4	0.62	0.77	0.36	0.65	0.92	0.54	1.54	1.20	0.85
5	0.75	1.20	0.37	0.78	1.31	0.78	1.58	1.38	1.28
6	0.80	1.36	0.38	0.87	1.40	0.92	1.59	1.43	1.30
7	0.81	1.48	0.49	0.95	1.59	0.99	1.75	1.57	1.64
8	0.83	1.51	0.63	0.98	1.83	1.01	1.91	1.90	1.67
9	1.00	1.59	0.65	1.00	2.01	1.07	1.95	1.91	1.94
10	1.06	1.62	0.67	1.03	2.09	1.12	2.00	1.96	1.99
11	1.16	1.69	0.81	1.05	2.13	1.18	2.06	2.17	2.05
12	1.20	1.70	0.91	1.07	2.39	1.28	2.13	2.18	2.25
13	1.27	1.82	0.96	1.27	2.40	1.39	2.47	2.19	2.46
14	1.31	1.97	1.16	1.42	2.71	1.61	2.62	2.24	2.79
15	1.38	2.02	1.24	1.67	2.88	1.73	2.69	2.28	2.83
16	1.72	2.16	1.30	1.68	3.04	1.87	2.71	2.33	2.98
17	1.84	2.39	1.33	1.71	3.06	1.93	2.79	2.40	3.02
18	2.03	2.43	1.34	1.80	3.30	1.95	3.04	2.49	3.07
19	2.65	2.54	1.40	1.88	3.33	2.16	3.06	2.50	3.10
20	2.66	2.55	1.44	1.94	3.36	2.23	3.16	2.53	3.14
21	2.83	2.63	1.49	2.01	3.45	2.72	3.29	2.54	3.22
22	2.89	2.65	1.71	2.13	3.46	2.82	3.66	2.61	3.28
23	3.01	2.74	1.74	2.25	3.56	2.90	3.83	2.64	3.32
24	3.05	2.76	1.83	2.55	3.57	2.93	3.92	2.76	3.34
25	3.25	2.85	1.84	2.62	3.63	3.00	4.03	2.81	3.73
26	3.39	2.94	1.91	2.67	3.70	3.02	4.04	2.85	3.91
27	3.52	3.11	1.92	2.71	3.75	3.18	4.05	2.89	3.92
28	3.58	3.15	1.99	2.74	3.81	3.24	4.15	2.91	3.98
29	3.64	3.25	2.05	2.75	3.87	3.49	4.45	2.92	3.99
30	3.86	3.32	2.06	2.76	3.90	3.58	4.46	2.97	4.11
31	4.01	3.45	2.11	2.80	3.92	3.60	4.64	3.20	4.13
32	4.44	3.47	2.14	2.83	3.97	3.62	4.67	3.34	4.21
33	4.47	3.63	2.32	2.85	3.98	3.70	4.70	3.35	4.24
34	4.54	3.71	2.34	2.86	4.19	3.75	4.89	3.37	4.26
35	4.66	3.75	2.41	3.02	4.22	3.88	4.92	3.48	4.34
36	4.83	3.95	2.42	3.04	4.28	3.99	4.93	3.51	4.39
37	4.89	4.03	2.44	3.05	4.38	4.02	5.41	3.58	4.69
38	4.94	4.07	2.48	3.06	4.51	4.04	5.54	3.67	4.75
39	5.08	4.09	2.62	3.18	4.58	4.26	5.71	3.69	4.76
40	5.27	4.11	2.76	3.27	4.60	4.27	5.80	3.71	4.89
41	5.29	4.59	2.81	3.29	4.66	4.29	5.84	4.09	4.90
42	5.41	4.71	2.84	3.32	4.70	4.32	5.96	4.16	5.15
43	5.44	4.80	2.96	3.33	4.89	4.46	6.27	4.17	5.31
44	5.51	4.83	3.16	3.42	4.97	4.70	6.32	4.45	5.37
45	5.58	4.95	3.18	3.46	5.04	4.75	7.23	4.55	5.48
46	5.61	5.00	3.20	3.57	5.09	5.04	7.66	4.65	5.94
47	5.71	5.02	3.29	3.61	5.21	5.09	7.79	4.68	6.28
48	5.77	5.12	3.32	4.16	5.47	5.10	7.91	4.70	6.64
49	6.08	5.21	3.35	4.18	5.62	5.12	8.00	4.73	6.71
50	6.13	5.43	3.36	4.20	5.72	5.28	8.22	5.27	6.93
51	6.16	5.44	3.42	4.25	5.85	5.39	8.34	5.66	7.10
52	6.25	5.45	3.57	4.59	6.10	5.71	9.05	5.67	7.25
53	6.56	5.47	3.69	4.61	6.23	5.77	9.36	5.87	7.67
54	6.87	5.49	3.84	4.69	6.39	5.91	9.54	5.96	7.97
55	6.88	5.60	3.89	4.71	6.46	5.95	9.58	5.97	7.99

Coal Fossil Units 500-599MW
NERC Data

Units	1999	2000	2001	2002	2003	2004	2005	2006	2007
56	7.20	5.63	4.11	4.77	7.14	6.08	10.09	5.99	8.03
57	7.25	5.67	4.28	4.78	7.59	6.14	10.14	6.09	8.08
58	7.44	5.76	4.75	4.81	7.70	6.20	10.19	6.78	8.11
59	7.55	5.83	4.97	4.83	7.75	6.33	10.33	6.97	8.22
60	7.66	5.86	5.13	4.94	7.78	6.53	10.37	7.06	8.54
61	7.69	5.98	5.23	5.27	7.95	6.64	10.53	7.27	8.67
62	7.79	6.09	5.29	5.28	7.97	6.70	10.85	7.50	8.78
63	7.86	6.22	5.35	5.46	8.04	6.71	10.94	7.54	8.83
64	8.14	6.30	5.47	5.72	8.06	6.73	11.17	7.59	9.05
65	8.22	6.40	5.54	6.23	8.11	6.85	11.54	7.69	9.37
66	8.28	6.56	5.56	6.35	8.40	7.14	11.55	7.74	9.39
67	8.61	6.62	5.76	6.36	9.39	7.55	12.21	7.75	9.53
68	8.62	6.85	6.07	6.39	9.44	7.88	12.29	8.30	9.61
69	8.64	7.18	6.41	6.40	9.49	8.23	12.39	8.44	9.67
70	8.65	7.19	6.55	6.50	9.70	8.26	12.82	8.45	9.93
71	8.73	7.28	6.62	6.72	9.89	8.52	13.25	9.65	10.21
72	8.78	7.36	6.69	6.77	10.47	8.54	13.56	9.97	10.27
73	9.05	7.52	6.71	6.99	10.66	8.72	13.80	10.48	10.49
74	9.18	7.65	7.11	7.03	10.71	8.77	15.62	10.51	10.53
75	9.33	7.66	7.32	7.07	11.10	8.99	15.72	10.61	10.65
76	9.60	7.71	7.40	7.17	11.27	9.02	16.01	11.08	11.39
77	9.85	7.87	7.42	7.31	11.44	9.19	16.18	11.10	11.42
78	9.95	7.92	7.89	7.64	11.55	9.37	17.18	11.26	11.84
79	10.09	8.03	8.02	7.85	11.66	9.48	22.68	11.45	11.85
80	10.14	8.24	8.07	7.93	12.23	9.50	22.99	11.55	11.98
81	10.27	8.38	8.20	8.11	13.10	9.68	23.02	11.98	12.00
82	10.32	8.59	8.47	8.18	13.15	9.78	24.55	12.09	12.27
83	10.43	9.05	8.63	8.32	13.56	10.26	26.09	12.34	12.70
84	10.88	9.37	8.70	8.96	15.79	11.20	33.51	12.42	12.72
85	10.90	9.53	10.68	9.42	16.58	12.02		12.74	12.74
86	11.23	9.89	11.17	9.74	16.80	12.48		12.90	12.91
87	11.31	9.91	11.59	9.76	17.70	12.51		14.62	13.90
88	11.92	10.22	12.66	10.62	18.03	13.21		15.96	14.80
89	12.33	10.25	12.93	10.98	18.94	14.15		22.24	14.90
90	12.38	10.32	13.15	11.36	19.03	14.38		23.02	15.00
91	13.26	10.38	14.00	11.58	22.72	14.57		23.47	15.03
92	13.45	11.88	16.31	11.69	26.09	15.50		26.41	15.18
93	14.03	11.92	16.69	12.47	33.40	16.29			16.14
94	14.44	12.09	16.83	12.69		16.48			18.08
95	14.78	12.66	16.94	12.74		17.86			18.78
96	15.27	13.65	21.30	13.85		20.45			19.00
97	16.80	13.81	21.36	15.25		22.61			31.65
98	20.00	19.32	56.15	26.61		33.07			
99	24.49	21.34		37.22		39.30			
100	24.92								
101	25.86								
102	89.14								
90th percentile	13.431	10.264	12.741	11.056	15.344	14.196	15.923	12.315	14.26
10th percentile	1.164	1.676	0.768	1.046	2.098	1.168	1.965	1.981	2.026
4 year average 90th percentile				11.87	12.35	13.33	14.13	14.44	14.17
4 year average 10th percentile				1.16	1.40	1.27	1.57	1.80	1.79

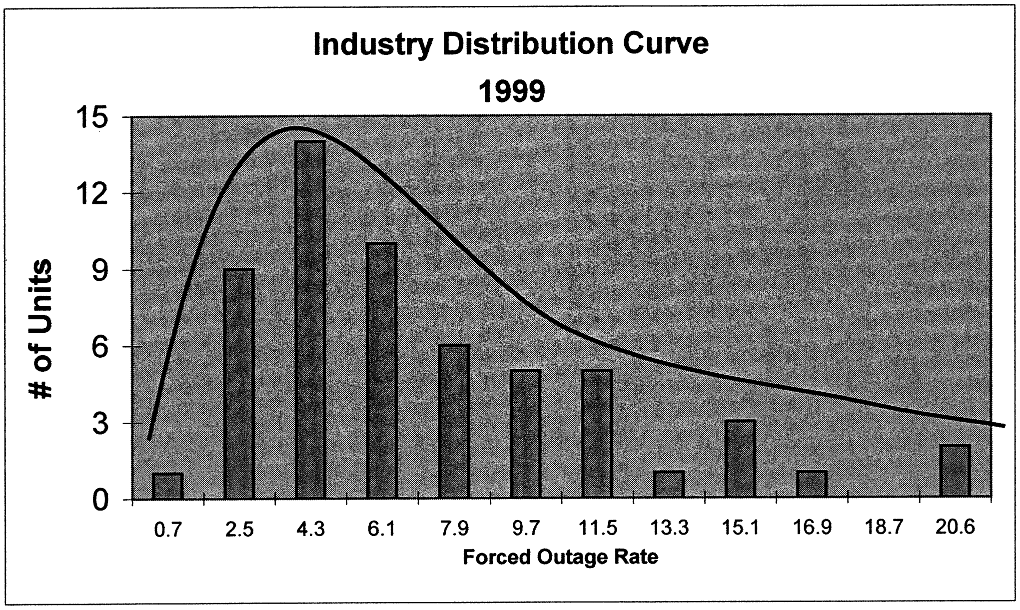
Coal Fossil Units 400-499MW
NERC Data

Units	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	0.37	0.36	0.00	0.03	1.29	0.54	0.15	0.00	0.33
2	0.60	0.95	0.19	1.04	2.19	0.63	0.70	0.08	0.59
3	1.54	1.10	0.22	1.27	2.38	0.71	1.02	0.10	0.71
4	2.02	1.23	0.48	1.30	2.74	0.94	1.46	0.25	1.77
5	2.21	1.58	1.16	1.38	2.95	1.24	1.50	0.34	2.00
6	2.33	1.66	1.39	1.40	2.99	1.47	1.78	0.79	2.17
7	2.56	1.88	1.45	1.51	3.13	1.93	2.07	1.04	2.36
8	2.75	2.26	1.59	1.64	3.18	2.43	2.34	1.17	2.52
9	3.09	2.39	1.86	1.66	3.33	2.45	2.65	1.78	2.67
10	3.14	2.56	1.88	1.75	3.38	2.61	2.84	2.01	2.97
11	3.22	2.67	1.89	1.82	3.46	2.85	2.96	2.22	3.17
12	3.28	2.94	1.95	1.94	3.70	2.95	3.27	2.67	3.24
13	3.83	3.32	3.14	2.11	3.78	3.03	3.28	2.86	3.68
14	3.95	3.60	3.35	2.12	3.90	3.05	3.34	3.11	3.85
15	4.17	3.69	3.38	2.34	3.97	3.08	4.17	3.19	3.88
16	4.42	3.80	3.65	2.59	3.99	3.36	4.53	3.86	4.05
17	4.61	3.87	3.73	2.70	4.06	3.41	4.59	4.91	4.41
18	6.44	4.74	3.77	2.88	4.65	3.43	5.00	5.13	4.44
19	6.66	4.92	4.07	3.01	4.79	3.47	5.08	5.20	4.73
20	7.00	5.21	4.21	3.02	5.09	3.48	5.74	5.56	4.92
21	7.01	5.66	4.70	3.26	5.18	3.54	6.00	5.69	5.05
22	7.05	5.85	4.84	3.31	5.22	3.67	6.09	5.95	5.36
23	7.17	6.07	5.13	3.46	5.63	3.71	6.27	5.97	5.54
24	7.24	6.37	5.25	3.56	5.98	3.73	6.52	6.39	5.78
25	7.26	6.40	5.26	4.01	6.02	3.84	6.72	6.46	5.94
26	7.48	6.62	5.55	4.15	6.24	3.94	6.97	6.69	6.07
27	8.13	7.19	5.67	5.09	6.43	4.05	8.47	7.03	6.16
28	8.29	7.31	6.36	6.21	6.51	4.11	9.01	7.13	6.34
29	8.45	7.35	7.52	6.35	6.69	4.54	9.22	7.22	6.58
30	9.13	7.41	7.69	6.85	6.73	4.90	9.30	7.63	7.33
31	9.98	8.05	7.71	7.06	8.25	6.19	9.78	7.69	7.68
32	10.12	8.14	7.75	7.75	9.35	6.71	9.82	7.95	8.10
33	10.60	9.29	8.01	7.82	9.41	6.94	11.01	8.25	9.04
34	10.79	9.37	8.05	8.33	10.42	7.74	12.26	8.56	9.35
35	11.14	11.19	8.16	8.70	10.90	8.20	13.88	8.79	9.80
36	11.65	11.21	8.53	8.99	11.04	9.01	15.48	8.86	11.31
37	13.32	12.26	10.90	9.67	12.14	9.99	17.63	11.56	12.39
38	14.58	12.81	10.99	10.30	12.85	11.65	19.18	13.00	13.07
39	15.51	13.59	14.91	11.92	13.76	12.65	20.12	14.92	14.96
40	17.01	15.33	19.41	14.55	17.44	13.68	20.36	15.90	15.62
41	19.12	16.15	21.25	14.96	18.30	16.73	22.57	16.12	17.12
42	21.41	16.30	26.97	17.49	23.77	18.17	31.59	16.33	20.78
43	27.59	16.39	36.55	19.88	30.64	18.42	32.37	26.89	22.41
44		17.99	38.65	21.45	32.87	19.07	42.23	29.01	22.42
45		22.36			36.67	23.97	46.46	33.26	34.07
46								39.49	
90th percentile	15.324	15.822	18.06	13.761	17.956	15.51	21.686	16.225	16.52
10th percentile	2.234	1.612	1.229	1.386	2.966	1.332	1.612	0.565	2.068

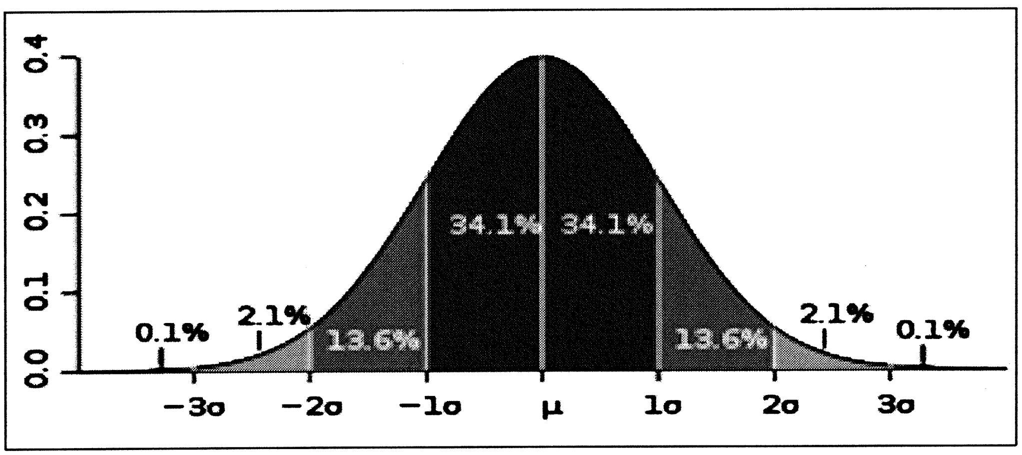
4 year average 90th percentile		15.74	16.40	16.32	17.23	17.84	17.49
4 year average 10th percentile		1.62	1.80	1.73	1.82	1.62	1.39

Coal Fossil Units 300-399MW
NERC Data

Units	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	0.38	0.37	0.07	0.00	0.22	0.13	0.07	0.41	0.13
2	0.65	0.48	0.28	0.04	0.53	0.34	0.49	0.72	0.77
3	1.33	0.61	0.33	0.06	0.78	0.60	1.02	0.77	0.82
4	1.44	0.67	0.51	0.07	0.79	0.69	1.13	0.94	0.84
5	1.60	0.68	0.55	0.13	0.84	0.85	1.14	1.01	0.89
6	1.64	0.95	0.67	0.41	1.01	0.92	1.24	1.08	1.19
7	1.83	1.04	0.78	0.46	1.08	0.93	1.33	1.19	1.23
8	1.84	1.25	0.79	0.51	1.09	1.03	1.45	1.22	1.83
9	1.86	1.28	0.94	0.53	1.15	1.16	1.64	1.27	1.91
10	2.16	1.29	0.98	0.60	1.17	1.18	1.73	1.35	2.06
11	2.18	1.34	1.11	0.73	1.22	1.19	1.87	1.40	2.07
12	2.42	1.36	1.28	0.75	1.65	1.47	2.12	1.48	2.30
13	2.71	1.57	1.29	0.87	1.79	1.63	2.15	1.76	2.34
14	2.93	2.01	1.31	0.88	1.94	1.72	2.56	1.94	2.37
15	2.95	2.30	1.36	0.92	2.22	2.14	2.75	1.96	2.40
16	3.03	2.47	1.40	0.94	2.31	2.22	2.80	2.07	2.49
17	3.28	2.51	1.57	0.98	2.38	2.25	2.90	2.16	2.59
18	3.43	2.56	1.74	0.99	2.40	2.30	3.05	2.26	2.66
19	3.58	2.60	1.77	1.09	2.55	2.33	3.11	2.28	2.70
20	3.92	2.79	1.84	1.13	2.66	2.60	3.15	2.31	2.84
21	4.05	2.84	1.85	1.14	2.81	2.78	3.22	2.48	2.94
22	4.12	2.91	1.91	1.19	2.84	2.97	3.47	2.49	3.02
23	4.23	2.98	1.97	1.20	2.95	3.00	3.73	2.53	3.09
24	4.31	3.09	2.07	1.26	3.06	3.06	3.86	2.83	3.10
25	4.33	3.23	2.09	1.30	3.23	3.16	3.89	3.02	3.31
26	4.40	3.35	2.10	1.31	3.78	3.19	3.97	3.14	3.42
27	4.54	3.49	2.28	1.52	3.89	3.23	3.98	3.21	3.76
28	4.59	3.93	2.29	1.55	4.01	3.42	4.30	3.34	4.05
29	4.66	4.20	2.57	1.82	4.08	3.72	4.64	3.66	4.20
30	4.80	4.35	2.62	2.39	4.10	3.73	4.86	3.71	4.31
31	4.84	4.63	2.71	2.42	4.24	3.83	4.93	4.00	4.73
32	4.94	4.67	2.72	2.58	4.38	4.04	5.01	4.01	5.05
33	5.00	4.77	2.79	2.59	4.41	4.27	5.38	4.19	5.20
34	5.07	4.89	2.89	2.96	4.65	4.32	5.40	4.21	5.26
35	5.22	4.91	3.29	3.09	4.83	4.66	5.71	4.91	5.39
36	5.56	5.01	3.36	3.13	4.86	4.91	5.86	4.94	5.55
37	5.57	5.29	3.37	3.41	4.91	5.26	5.97	5.12	5.69
38	5.80	5.70	3.40	3.43	4.93	5.39	6.15	5.34	5.82
39	5.83	5.90	3.46	3.64	5.02	5.48	6.33	5.57	5.85
40	6.09	6.14	3.55	4.20	5.05	5.69	6.63	5.76	5.90
41	6.36	6.24	3.62	4.25	5.25	5.77	6.71	5.81	6.01
42	6.66	6.46	3.74	4.47	5.31	5.78	7.06	5.89	6.62
43	7.30	6.86	3.82	4.68	5.38	5.82	7.28	6.28	6.73
44	7.38	6.95	3.98	4.69	5.45	5.88	7.53	6.75	6.78
45	7.63	7.07	5.24	4.97	5.51	5.90	8.09	6.76	7.19
46	7.68	7.15	5.53	5.23	5.94	5.99	8.18	6.83	7.23
47	8.15	7.43	5.77	5.29	6.07	6.11	8.27	6.95	7.37
48	8.18	7.62	5.80	5.32	6.23	6.38	8.33	7.04	7.67
49	8.39	7.69	5.95	5.38	6.38	6.43	8.37	7.18	7.68
50	8.41	7.72	6.15	5.42	6.48	6.45	8.50	8.03	7.80
51	8.77	7.82	6.69	5.64	6.96	7.02	8.69	8.26	8.18
52	9.06	8.02	6.72	6.05	7.38	7.11	9.41	8.32	8.21
53	9.43	8.61	6.85	6.40	7.50	7.18	9.47	8.34	8.24
54	9.62	9.10	7.36	6.57	7.61	7.39	9.56	8.76	8.75
55	10.29	9.49	7.64	6.63	8.13	7.45	10.00	8.77	8.83
56	10.35	11.65	8.31	6.76	8.74	7.63	10.43	8.86	9.44
57	10.79	11.70	8.85	7.09	8.78	8.29	10.52	8.90	9.64
58	11.12	12.13	8.87	7.21	8.80	8.46	10.67	9.03	10.42
59	11.43	12.15	8.89	8.09	8.84	9.16	10.68	9.13	11.17
60	11.72	13.38	9.60	8.91	9.06	9.27	11.14	9.49	11.75
61	12.06	15.61	9.90	9.00	9.72	9.57	11.59	9.50	12.48
62	12.39	15.97	10.18	9.43	11.02	9.60	12.57	10.83	12.52
63	12.66	16.71	12.09	9.70	11.25	9.89	16.46	12.52	12.70
64	13.18	29.54	15.06	9.85	11.28	10.08	16.90	13.29	13.28
65	13.57	37.72	16.48	9.97	11.47	10.29	17.44	13.61	13.44
66	13.89	62.44		10.68	12.10	10.74	17.99	13.63	13.51
67	14.19	84.85		11.21	12.20	13.18	26.20	14.62	13.94
68	14.56			12.55	12.38	16.01		17.09	17.40
69	14.86				13.69	16.27		20.59	18.68
70	15.09				23.59	18.96			19.30
71	16.30					26.22			23.20
72	17.06					31.57			29.42
73	17.48					36.81			59.75
74	18.40								66.77
90th percentile	14.10	14.27	8.88	9.13	11.25	10.65	11.32	11.17	13.81
10th percentile	1.85	1.17	0.78	0.50	1.09	1.06	1.40	1.21	1.85
4 year average 90th percentile				11.60	10.88	9.98	10.59	11.10	11.74
4 year average 10th percentile				1.07	0.88	0.86	1.01	1.19	1.38



NERC Industry data distribution curve, 600-699 MW, 1999



Normal Distribution or Bell Curve

The Normal Distribution curve shows the following:

The mean is the μ symbol and a standard deviation is the σ symbol.
68 % of the values fall within 1 standard deviation of the mean.
95% of the values fall within 2 standard deviations of the mean.
99.7% of the variables fall within 3 standard deviations of the mean.
less than 1% of the variables falling outside 3 standrd deviations from the mean.

By comparison, the NERC distribution curve, above, of the 1999 forced outage rates shows:

Where the mean = 6.5 and the std dev = 4.6
75% of the values fall within 1 standard deviation, the value will be less than 11.1, or greater than 1.9.
95% of the values fall within 2 standard deviations, the value will be less than 15.7 or greater than -2.7
100% of the values fall within 3 standard deviations, the value will be less than 20.3
However, as you can see these are not equally distributed on both sides of the mean.

CERTIFICATE OF SERVICE

UM 1355

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

Dated at Salem, Oregon, this 7th day of April, 2009.

Kay Barnes

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Public Utility Commission
Regulatory Operations
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UM 1355
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