Oregon

Theodore R. Kulongoski, Governor

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July 18th, 2006

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
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RE: **Docket No. UE 180/UE 181** - In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180) And 2007 Resource Valuation Mechanism (UE 181).

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

/s/ Kay Barnes

Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

c: UE 180 and UE 181 Service List - parties

PUBLIC UTILITY COMMISSION OF OREGON

UE 180/UE 181

STAFF DIRECT TESTIMONY OF

Maury Galbraith
Bill Wordley
Ed Durrenberger

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision (UE 180)
And
2007 Resource Valuation Mechanism (UE 181)

REDACTED VERSION

July 18, 2006

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Direct Testimony

July 18, 2006

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Maury Galbraith. The Public Utility Commission of Oregon (OPUC) employs me as a Senior Economist. My qualifications are shown on Exhibit Staff/101.

Introduction and Summary

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I summarize staff's analysis of Portland General Electric's (PGE's) forecast of net variable power cost for 2007. Staff has analyzed the MONET (Monet) updates included in PGE's Resource Valuation Mechanism (RVM) and the Monet enhancements included in PGE's general rate case. Second, I present staff's recommendations regarding the equivalent forced outage rate (EFOR) to use in modeling the expected generation from the Boardman and Colstrip units in 2007.

Q. DO YOU PRESENT ANALYSIS OF PGE'S PROPOSED POWER COST FRAMEWORK, INCLUDING THE PROPOSED ANNUAL POWER COST UPDATE AND ANNUAL VARIANCE TARIFF?

A. No. Pursuant to the Administrative Law Judge's Pre-hearing Conference Report, staff will present its testimony on the proposed power cost framework on August 9, 2006.

Q. DOES STAFF PRESENT ANY OTHER WITNESSES IN THIS FILING?

A. Yes. Bill Wordley, a Senior Economist in the Economic Research and Financial Analysis section, provides testimony on two power cost adjustments. Staff Exhibit 200. The first adjustment adds revenue for ancillary services the company sells. The second adjustment includes the extrinsic value of PGE's flexible generation and contract resources in the forecast of power costs for 2007. Ed Durrenberger, a Senior Analyst in the Rates and Tariffs section, provides testimony on PGE's proposal to include an estimate of the amount of coal lost during transportation from Wyoming to the Boardman plant in its Monet forecast of 2007 power costs. Staff Exhibit 300.

Q. PLEASE SUMMARIZE STAFF'S POWER COST RECOMMENDATIONS.

A. Staff makes the following recommendations:

- Staff witness Galbraith recommends 'normal' equivalent forced outage rates of 7.67 percent for Boardman and 7.69 percent for Colstrip. Staff estimates that these adjustments will reduce PGE's final net variable power cost by $6,592,000 and $6,255,000, respectively.
- Staff witness Wordley recommends a $1,647,885 reduction to PGE's proposed power cost in order to appropriately match the revenues and costs from PGE providing ancillary services to wholesale market participants. Mr. Wordley also recommends a $12,352,530 reduction to net variable power cost to account for the extrinsic value of PGE's natural gas-fired generation and capacity tolling agreements.
- Staff witness Durrenberger recommends that the Commission reject PGE's proposed enhancement of its Monet model to reflect coal 'lost' during railroad transportation from Wyoming to the Boardman plant. This disallowance reduces PGE's proposed power cost by $354,000.

PGE's Power Cost Forecasts For 2007

Q. PLEASE SUMMARIZE PGE'S POWER COST FORECASTS.

A. The following table summarizes PGE's forecasts of 2007 power costs in its RVM and general rate case filings.

Table 1. PGE's Power Cost Forecasts.

	Power Cost ($000)
2007 RVM Filing (UE 181)	**813,786**
Include Schedule 125 Part B Load	+50,854
Include Monet Changes	-7,671
2007 GRC Filling (UE 180)	**856,968**
Include Port Westward	-9,648
2007 Port Westward Tracker (UE 184)	**847,321**

Staff will present its testimony regarding Port Westward on August 9, 2006.

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENTS TO PGE'S POWER COST FORECASTS.

A. The following table summarizes staff's proposed power cost adjustments.

Table 2. Staff's Power Cost Adjustments.

	Power Cost ($000)
PGE's UE 180 Forecast	**856,968**
Boardman Forced Outage Rate Adjustment (S-4)	-6,592
Colstrip Forced Outage Rate Adjustment (S-4)	-6,255
Ancillary Services (S-16)	-1,648
Extrinsic Value Adjustment (S-10)	-12,353
Coal Loss Adjustment (S-7)	-354
Staff's Adjusted Forecast	**829,766**

The adjustments should be applied in Dockets UE 180, UE 181 and UE 184.

Coal Unit Forced Outage Rates

Q. PLEASE DEFINE THE TERMS 'FORCED OUTAGE' AND 'FORCED OUTAGE RATE'.

A. A forced outage is an unplanned failure of a generating unit that requires the unit to be immediately removed from service. A forced outage rate is a proportion of forced outage hours to total hours a unit was capable of providing service on an annual basis. For example, a unit might be scheduled for maintenance during 10 percent of a year and, therefore, capable of providing service for 7,884 hours (i.e., 8,760 annual hours * (1 - 0.10) = 7,884 available hours). If the unit was forced out of service for 394 hours during the year, then the unit's forced outage rate is 5 percent (i.e., 394 forced outage hours / 7,884 available hours = 5 percent).

Q. HOW ARE FORCED OUTAGE RATES USED IN THE RATEMAKING PROCESS?

A. Forced outages rates are used in ratemaking to reflect normal generating unit availability in the determination of test period power costs. In other words, forced outage rates are input into a utility's power cost model to normalize power costs on a going-forward basis. For example, assume a unit has a capacity of 100 MW and has a normal forced outage rate of 10 percent. In this hypothetical example, the utility's power cost model would economically dispatch the unit at a capacity of 90 MW per hour during the test period (i.e., 100 MW * (1 – 0.10) = 90 MW).[1]

Q. HOW ARE 'NORMAL' FORCED OUTAGE RATES DETERMINED?

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[1] This hypothetical example assumes that there is no scheduled maintenance outage.

A. Oregon's three electric investor-own utilities have traditionally used a four-year rolling average of actual unit forced outage rates to determine a unit's normal forced outage rate. Staff Exhibit 102 is a staff policy statement from 1984 recommending the four-year rolling average method for determining normal forced outage rates. In making his recommendation, Staff analyst Tom Harris states:

> The reason I propose using a 48-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. Staff/102, Galbraith/4.

<u>**Boardman**</u>

Q. PLEASE SUMMARIZE THE HISTORIC FORCED OUTAGE RATE OF PGE'S BOARDMAN UNIT.

A. In direct testimony, PGE provided actual plant availability factors for 2001 through 2005 for each of its thermal units. *See* UE 180, PGE/300, Quennoz – Schue/19-20. It is simple to calculate a unit's forced outage rate from its availability factor (i.e., forced outage rate = (1 - availability factor)). The following table shows the historic forced outage rate of Boardman.

Table 3. Boardman Forced Outage Rates 2001-2005.

	Availability Factor	Forced Outage Rate
2001	97.11 %	2.89 %
2002	91.88 %	8.12 %
2003	95.79 %	4.21 %
2004	88.49 %	11.51 %
2005	75.89 %	24.11 %

The higher forced outage rate in 2005 reflects 70 days of forced outage attributable to the October 23, 2005 event that is the subject of PGE's deferral application in Docket UM 1234.

Q. IN DOCKET UM 1234, YOU TESTIFIED THAT THE OCTOBER 23, 2005, FORCED OUTAGE AT BOARDMAN WAS AN EXTREME EVENT. IS IT REASONABLE TO INCLUDE EXTREME EVENTS IN A FOUR-YEAR AVERAGE FOR THE PURPOSE OF DETERMING A UNIT'S 'NORMAL' FORCED OUTAGE RATE?

A. No. The simple average of Boardman's forced outage rates in 2002-2005 is 12 percent. The simple average gives equal weight to each of the four annual forced outage rates. But, on a going-forward basis, one would not expect a 24.11 percent annual forced outage rate to occur with equal frequency as an 8.12 percent forced outage rate. It is unreasonable to include an extreme outage in the rolling four-year average calculation of a unit's 'normal' forced outage rate because the methodology inappropriately gives too much weight to the extreme event.[2]

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[2] PGE's actual four-year forced outage rate is calculated from average period hours, average planned outage hours, average reserve shutdown hours, and average equivalent availability factor. The calculation is essentially a weighted average. The criticisms of the simple four-year average are still valid for PGE's actual calculation.

Q. WHAT ARE THE POTENTIAL REMEDIES FOR THIS FLAW IN THE TRADITIONAL METHODOLOGY FOR CALCULATING 'NORMAL' FORCED OUTAGE RATES?

A. Staff has identified three remedies that depart from the traditional methodology in increasing degree. The first remedy is to adjust the inputs to the four-year average to remove the effect of the extraordinary outage. The second remedy is to abandon the use of unit-specific availability data and determine 'normal' forced outage rates based on an industry-wide average. The third remedy is to abandon the use of point-estimates of a unit's 'normal' forced outage rate and instead use Monte Carlo simulation to determine power costs based on a probability-weighted range of unit outage rates.

Q. HAS STAFF EXPLORED THE FIRST REMEDY?

A. Yes. In this "deferral" approach, staff adjusted the traditional four-year average calculation of Boardman's 'normal' forced outage rate by removing the hours in the November 18, 2005 through December 31, 2005 deferral period (*see* Docket UM 1234) from the forced outage hours and the period hours used in the traditional calculation. This has the effect of truncating the traditional 48-month average to a slightly less than 46-month average. This approach results in a 'normal' forced outage rate for Boardman of 9.01 percent. Inputting this rate into PGE's Monet model results in a $4.598 million reduction to net variable power costs.

Q. IS THERE PRECEDENT FOR THIS TYPE OF ADJUSTMENT?

A. Yes. PacifiCorp made a similar adjustment for the extreme outage at its Hunter 1 unit that began on November 25, 2000. PacifiCorp removed the hours associated with this outage from the traditional four-year average forced outage rate calculation in Dockets UE 134, UE 147, and UE 170.

Q. WHAT ARE THE WEAKNESSES OF THIS ADJUSTMENT?

A. There are two weaknesses associated with removing the deferral period hours from the forced outage rate calculation. First, simply removing the deferral period hours from the calculation does not guarantee the result will reflect the unit's 'normal' forced outage rate. This adjustment may overshoot or undershoot that desired target. Second, linking the calculation of the unit's 'normal' forced outage rate, a forward-looking consideration, with deferred accounting, a backward-looking endeavor, can create confusion about the underlying purpose of modeling forced outage rates when determining the power cost to include in base rates. The purpose of including unit outage rates in power cost modeling is to normalize unit availability during the test period. The modeling of unit forced outage rates is not intended to provide recovery of the replacement power costs associated with past outages. The recovery (or true-up) of actual replacement power costs through deferred accounting is a separate issue that comes after the normalization of power costs in base rates.[3]

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[3] For a discussion of this distinction and its application to the issue of "double recovery" of unit outage costs see Docket UE 170, Staff/800, Wordley/10-11.

Q. HAS STAFF EXPLORED THE SECOND REMEDY: SETTING BOARDMAN'S 'NORMAL' FORCED OUTAGE RATE ON THE BASIS OF AN INDUSTRY-WIDE AVERAGE?

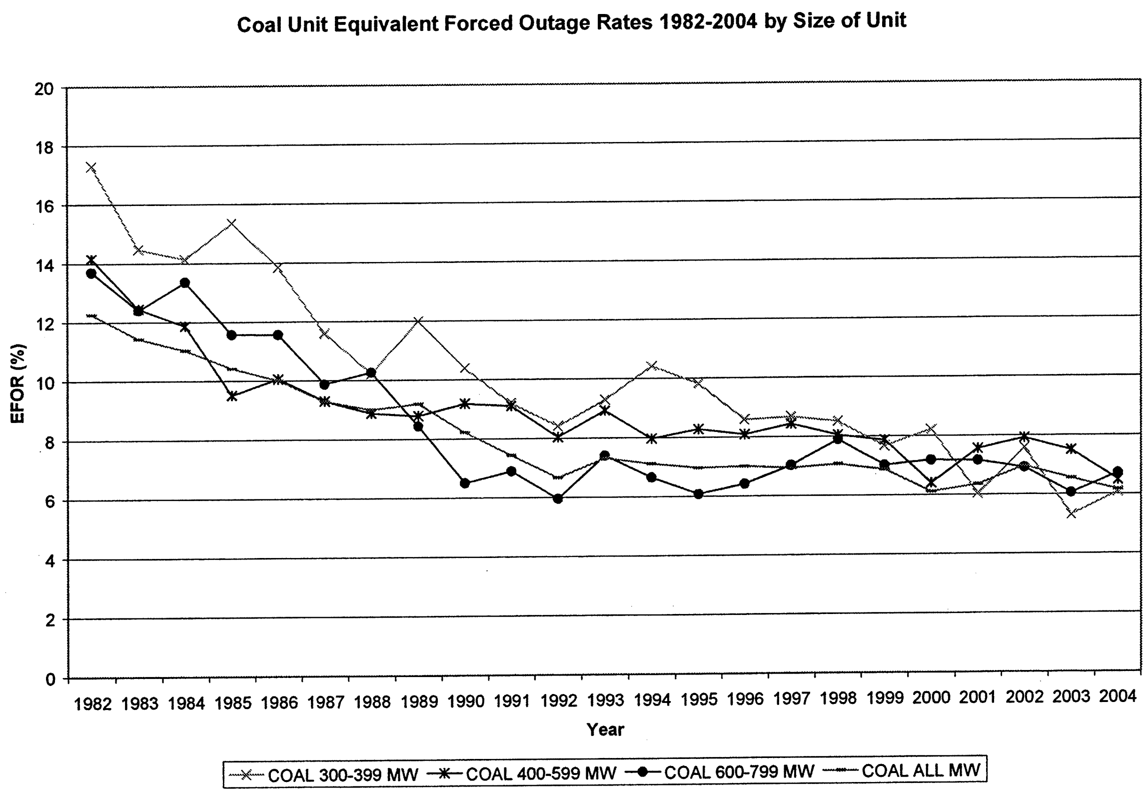
A. Yes. The North American Electric Reliability Council (NERC) publishes two annual reports summarizing the statistical performance of various classes, or peer groups, of generation units. The Generating Availability Report (GAR) presents generating unit availability statistics for the most recent five-year period. Staff Exhibit 103 is the section of the 2000-2004 GAR covering coal unit performance. The Historical Availability Statistics (HAS) report presents availability information starting from 1982 through the most current year. Staff Exhibit 104 is the section of the 2000-2004 HAS covering coal unit performance.

Q. HAS STAFF IDENTIFIED AN APPROPRIATE NERC PEER GROUP FOR THE BOARDMAN PLANT?

A. Yes. NERC groups units based on fuel type and unit size. To assure consistent classification from year-to-year, NERC uses the turbine nameplate rating in its determination of unit size. PGE's Boardman plant has a nameplate rating of 530 MW. The appropriate NERC peer group for Boardman is coal units with a nameplate capacity between 400 and 599 MW. This peer group had annual average forced outage rates of 6.40 percent in 2000, 7.56 percent in 2001, 7.91 percent in 2002, 7.49 percent in 2003, and 6.48 percent in 2004. The 'Coal 400-599 MW' peer group averaged 147 units and provided 736 unit-years of commercial service over the period 2000-2004. In 2004, the 146 units in this peer group had an average age of 28 years. In comparison, Boardman was 24 years old.

Q. HOW DO THE AVERAGE ANNUAL FORCED OUTAGE RATES FOR THIS PEER GROUP COMPARE TO OTHER NERC PEER GROUPS?

A. The following chart shows time-series of the annual equivalent forced outage rates for four classes of coal units. The data show similar trends for each of the four peer groups.



Q. THE YEAR-TO-YEAR CHANGE IN PEER GROUP FORCED OUTAGE RATES APPEARS TO BE LESS THAN THAT OF PGE'S BOARDMAN UNIT. IS THIS RESULT TO BE EXPECTED WHEN MAKING THIS TYPE OF COMPARISON?

A. Yes. The annual statistics in the NERC reports are composites, representing the performance of a large group of units. I would expect the average annual performance of a peer group of units to be less volatile than the performance of a single unit.

Q. HAS STAFF IDENTIFIED A 'NORMAL' FORCED OUTAGE RATE FOR BOARDMAN BASED ON THIS PEER GROUP ANALYSIS?

A. Yes. The most recent five-year average equivalent forced outage rate for the 'Coal 400-599 MW' peer group is 7.15 percent. This average gives a more reasonable weighting to extreme outage events. Inputting this rate into PGE's Monet model results in a $7.366 million reduction to net variable power costs.

Q. IS THERE PRECEDENT FOR THIS TYPE OF ADJUSTMENT?

A. Yes. In the 1984 staff policy statement on the methodology for determining 'normal' forced outage rates, Staff proposed a blended average outage rate for Boardman. The proposed rate was based on 38 months of actual data from Boardman and 10 months of data from a national average. Staff/102, Galbraith/14. In recommending the blended average, Staff analyst Tom Harris stated:

> 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. Staff/102, Galbraith/14.

Q. WHAT ARE THE WEAKNESSES OF THIS ADJUSTMENT?

A. In the NERC Generating Availability Data System (GADS), some of the outage hours reported as planned outage hours may in fact reflect 'forced' maintenance hours.[4] As a result, the reported statistics may understate equivalent forced outage rates for power cost normalization purposes.

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[4] A "forced maintenance" outage is one where the outage is delayed until a more convenient time to make the needed repairs. Plants typically report this delayed outage as a "maintenance" outage but, for power cost normalization purposes, it is more appropriate to count it as a "forced" outage.

Q. IS STAFF ABLE TO ADJUST THE NERC AVERAGE EQUIVALENT FORCED OUTAGE RATE TO ACCOUNT FOR 'FORCED' MAINTENANCE OUTAGES?

A. Yes. In recent RVM proceedings, PGE has adjusted the inputs to the traditional four-year average calculation to account for 'forced' maintenance hours. The adjustment factor for 'forced' maintenance hours averaged 7.26 percent over the 2002-2005 period. Applying this PGE adjustment factor to the NERC 'Coal 400-599 MW' peer group equivalent forced outage rate results in an adjusted rate of 7.67 percent (i.e., 7.15 percent * (1 + 7.26 percent) = 7.67 percent). Inputting this rate into PGE's Monet model results in a $6.592 million reduction to net variable power costs.

Colstrip

Q. HAS STAFF COMPARED THE PERFORMANCE OF PGE'S COLSTRIP UNITS TO AN APPROPRIATE NERC PEER GROUP?

A. Yes. Colstrip units 3 and 4 each have a nameplate capacity 700 MW. The appropriate NERC peer group for these units is 'Coal 600-799 MW'. This peer group had annual average forced outage rates of 7.17 percent in 2000, 7.16 percent in 2001, 6.91 percent in 2002, 6.05 percent in 2003, and 6.71 percent in 2004. The five-year average equivalent forced outage rate for this class of units is 6.79 percent. In contrast, PGE has determined that the 'normal' test period forced outage rate for these units is 12.4 percent. *See* UE 181, Tooman – Niman – Schue/12.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE NERC 'COAL 600-799 MW' PEER GROUP?

A. Yes. The 'Coal 600-799 MW' peer group averaged 87 units and provided 430 unit-years of commercial service over the period 2000-2004. In 2004, the 91 units in this peer group had an average age of 27 years. In comparison, PGE's Colstrip units were 19 years old.

Q. WAS COLSTRIP'S PERFORMANCE UNIFORMLY POOR ACROSS THE 2002-2005 PERIOD OR IS COLSTRIP'S ABOVE-PEER-GROUP-AVERAGE ATTRIBUTABLE TO A SINGLE BAD YEAR?

A. The traditional four-year average equivalent forced outage rate for Colstrip is impacted by particularly poor unit performance in 2002. The composite Colstrip availability factor in 2002 was 76.95 percent compared to an average 91.31 percent availability factor for the other years. *See* UE 180, PGE/300, Quennoz – Schue/19-20. It is unreasonable to include the 23.05 percent forced outage rate from 2002 in the rolling four-year average calculation of Colstrip's 'normal' forced outage rate because this methodology inappropriately gives too much weight to this extreme outage rate.

Q. HAS STAFF IDENTIFIED A 'NORMAL' FORCED OUTAGE RATE FOR COLSTRIP BASED ON THIS PEER GROUP ANALYSIS?

A. Yes. The most recent five-year average equivalent forced outage rate for the 'Coal 600-799 MW' peer group is 6.79 percent. This average gives a reasonable weighting to extreme outage events. Inputting this rate into PGE's Monet model results in a $7.450 million reduction to net variable power costs.

Q. SHOULD THE NERC EQUIVALENT FORCED OUTAGE RATE BE ADJUSTED TO ACCOUNT FOR 'FORCED' MAINTENANCE OUTAGES?

A. Yes. The PGE adjustment factor for 'forced' maintenance hours at Colstrip averaged 13.27 percent over the 2002-2005 period. Applying this adjustment factor to the NERC 'Coal 600-799 MW' peer group equivalent forced outage rate results in an adjusted rate of 7.69 percent (i.e., 6.79 percent * (1 + 13.27 percent) = 7.69 percent). Inputting this rate into PGE's Monet model results in a $6.255 million reduction to net variable power costs.

Q. YOU HAVE DESCRIBED A NUMBER OF ADJUSTMENTS TO THE FORCED OUTAGE RATES FOR THE BOARDMAN AND COLSTRIP UNITS. PLEASE SUMMARIZE THESE ALTERNATIVES AND CLEARLY STATE STAFF'S RECOMMENDATIONS TO THE COMMISSION.

A. The following table summarizes the alternative adjustments.

Table 4. Alternatives to PGE's 'Normal' Equivalent Forced Outage Rates for Boardman and Colstrip.

	Amount ($000)
Boardman	
'Normal' based on deferral adjustment	-4,598
'Normal' based on NERC Peer Group	-7,366
'Normal' based on Adjusted NERC Rate	-6,592
Colstrip	
'Normal' based on NERC Peer Group	-7,450
'Normal' based on Adjusted NERC Rate	-6,255
Staff Recommendation	
'Normal' based on Adjusted NERC Rates	-12,847

Staff recommends that the Commission use the adjusted NERC peer group equivalent forced outage rates as the 'normal' test period rates for Boardman and Colstrip.

Q. AT THE BEGINNING OF THIS TESTIONY YOU MENTIONED A THIRD REMEDY: USING MONTE CARLO SIMULATION TO DETERMINE 'NORMAL'

POWER COSTS BASED ON A PROBABILITY-WEIGHTED AVERAGE OF UNIT FORCED OUTAGES. PLEASE DISCUSS THIS REMEDY.

A. Staff has proposed the use of stochastic power cost modeling in several recent dockets (e.g., UE 165, UE 173, and UE 179). Thermal unit forced outages are largely independent of variation in hydroelectric generation, market electricity prices, market natural gas prices, and retail load. Given this independence, thermal forced outage rates can be a separate first step towards Monte Carlo simulation of net power costs. Production cost models such as AURORA, developed by EPIS, Inc., and Planning & Risk, developed by Global Energy Decisions, Inc., have Monte Carlo forced outage rate functionality. Monte Carlo simulation of unit forced outages has several advantages. First, it can provide an appropriate weighting of forced outages of different durations. Second, it can provide a more realistic simulation of unit operation. Instead of de-rating the unit by a fixed percent in every hour of the test period, Monte Carlo simulation can better reflect the actual pattern of unit operation.

Q. DOES THE NERC GADS APPEAR TO BE A GOOD DATA SOURCE FOR DEVELOPING DISTRIBUTIONS OF THE FREQUENCY AND DURATION OF PEER GROUP FORCED OUTAGES?

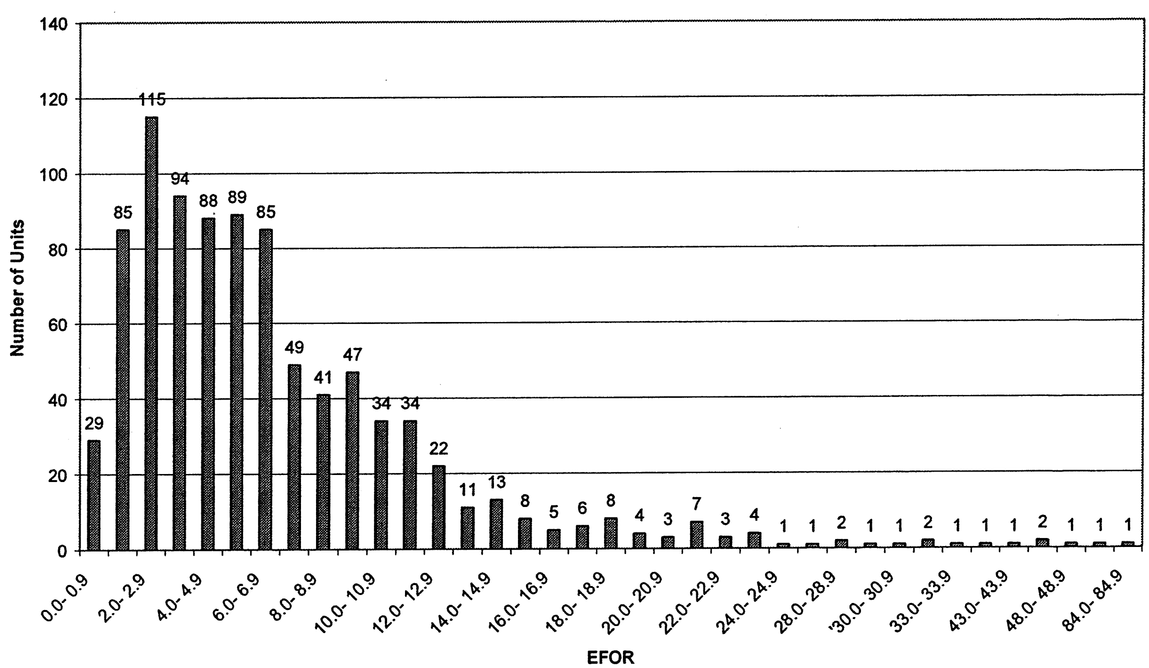
A. Yes. For example, the units in the 'Coal 400-599 MW' 'per group averaged 11.11 forced outages per unit-year of service over the period 2000-2004. Staff/103, Galbraith/11. The underlying distribution of the number of occurrences per unit-year of service could be used as a measure the likelihood of peer group forced outages. The NERC GADS also contains data on the duration of forced outages. *See* UM 1234, PGE/302, Drennan-Tinker-Hager/1-2.

NERC GADS Services can provide tailored peer group datasets with a large number of peer units and a representative distribution of forced outages.[5]

Q. DOES NERC REPORT THE DISTRIBUTION OF KEY PERFORMANCE PARAMETERS?

A. Yes. Staff Exhibit 105 is the section of the 2000-2004 GAR covering the distribution of key statistics on coal unit performance. For example, in addition to reporting that coal units of all MW sizes had an average equivalent forced outage rate of 6.43 percent over the 2000-2004 period, NERC also reports the underlying distribution of this parameter. The following chart shows the distribution of equivalent forced outage rates for coal plants of all sizes.

Distribution of Coal Unit Equivalent Forced Outage Rates
All MW Sizes, 2000-2004
N = 900 Units



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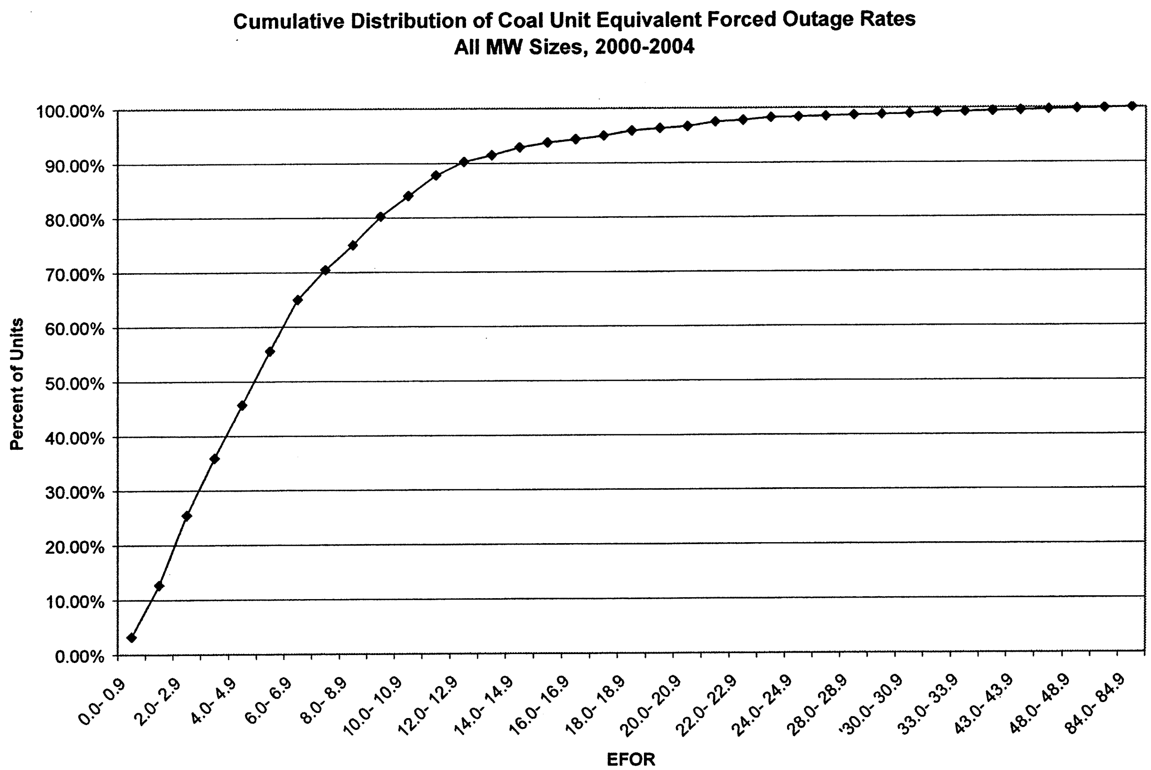
[5] For a description of these services see http://www.nerc.com/~gads/benchmarking.html

The distribution of coal unit forced outage rates is bounded by zero and asymmetrically skewed towards high forced outage rates. The following chart shows the cumulative distribution of equivalent forced outage rates for the same group of units.



Roughly 88 percent of all coal units in the NERC GADS database had a forced outage rate less than 12 percent for the period 2000-2004. In conclusion, Staff believes it is more appropriate to normalize power costs using Monte Carlo techniques to simulate the full range of potential forced outages based on peer group performance statistics than to simply de-rate a unit's capacity in each hour of a test period using a single forced outage rate based on that unit's average performance over the last four years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 18, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Maury Galbraith
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Energy Division
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2551
EDUCATION:	Graduate Student in Environmental Studies Program (1995 – 1997) University of Montana Missoula, Montana Master of Arts in Economics (1992) Washington State University Pullman, Washington Bachelor of Science in Economics (1989) University of Oregon Eugene, Oregon
EXPERIENCE:	The Public Utility Commission of Oregon has employed me since April 2000. My primary responsibility is to provide expert analysis of issues related to power supply in the regulation of electric utility rates. From April 1998 through March 2000 I was a Research Specialist with the State of Washington Office of the Administrator for the Courts in Olympia, Washington. From April 1993 through August 1995 I was a Safety Economist with the Pacific Institute for Research and Evaluation in Bethesda, Maryland.

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support of
Direct Testimony

July 18, 2006

PUBLIC UTILITY COMMISSIONER OF OREGON

STATE OF OREGON 1859
VICTOR ATIYEH GOVERNOR

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

CC: 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.

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

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

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

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.

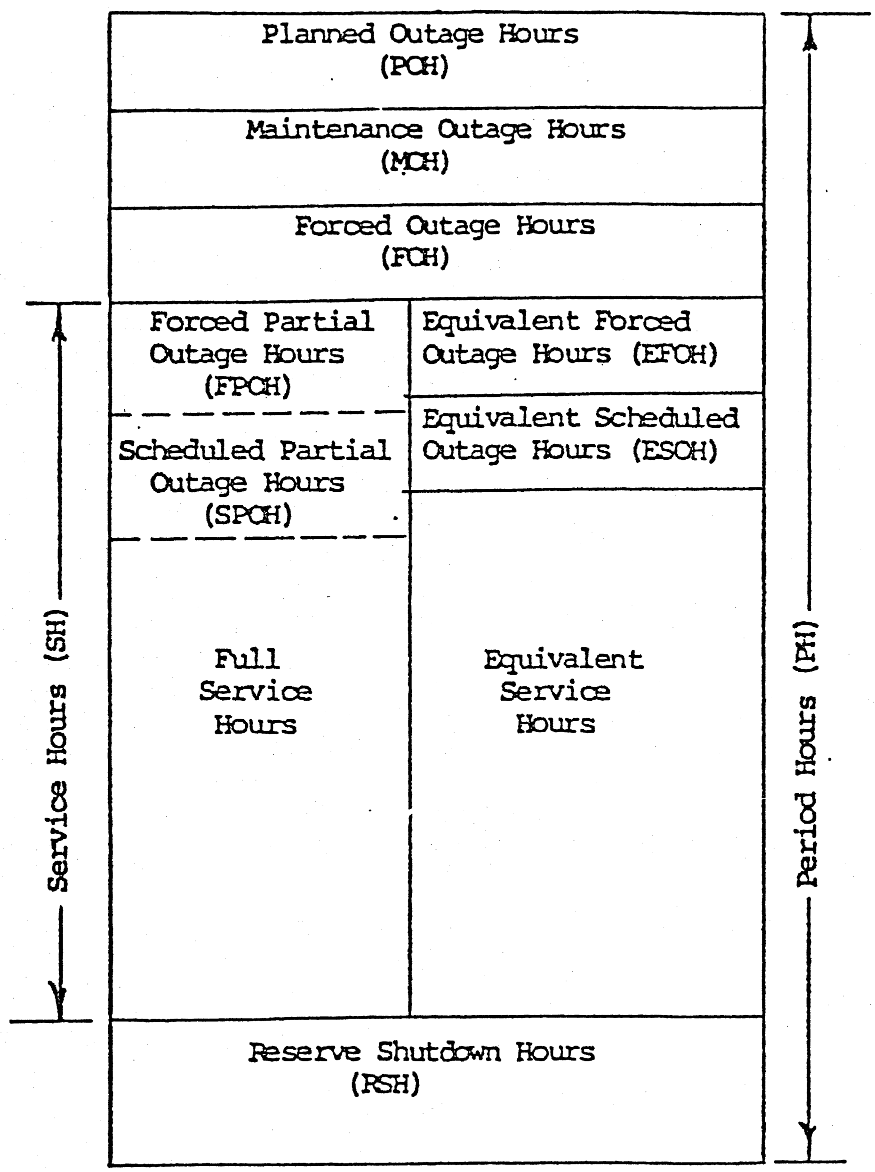
MW Net - Megawatts Net - Net megawatts available from a unit or plant excluding station use. For our purpose here:

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

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.

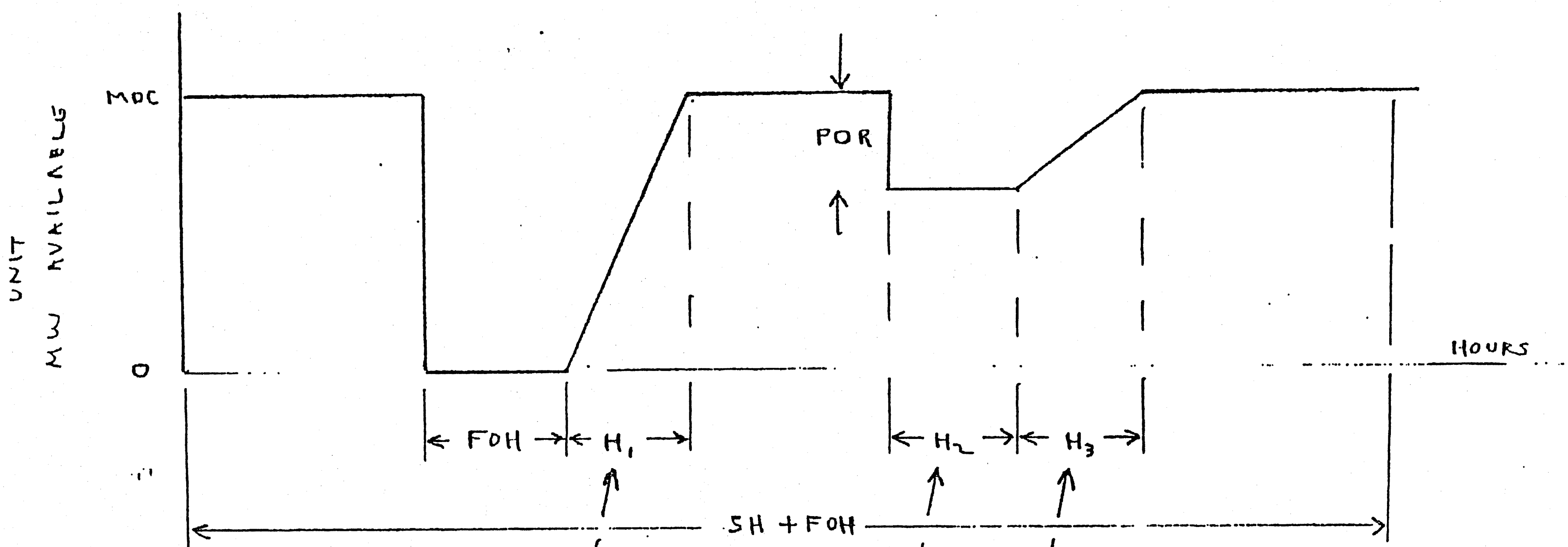
The procedures for calculating EFOH and ESOH are illustrated on the following two pages. The procedures are alike. It can be seen that EFOH and ESOH are the sum of equivalent outage hours for several partial forced or partial scheduled outages.

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



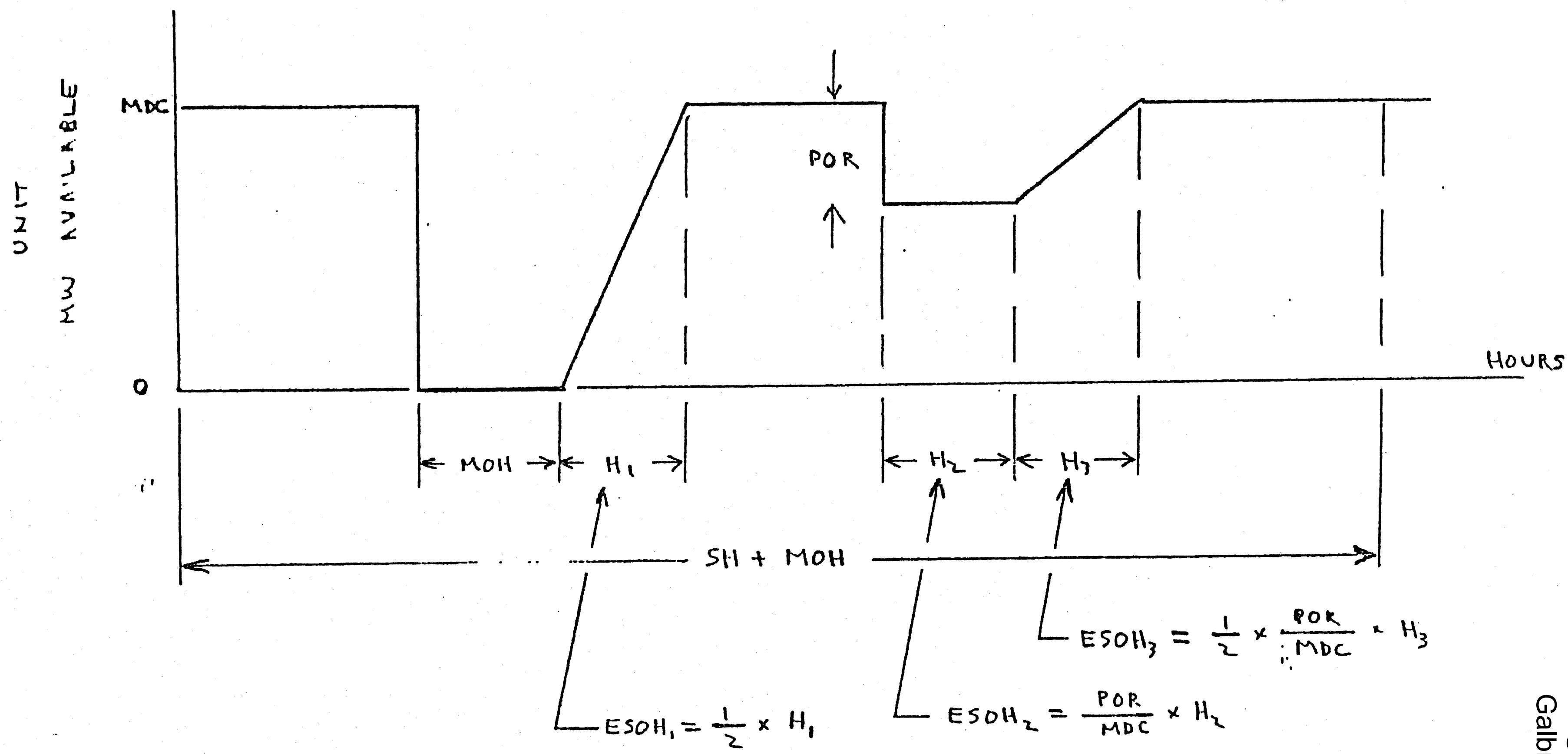
$$EFOH_1 = \frac{1}{2} \times H_1$$

$$EFOH_2 = \frac{POR}{MDC} \times H_2$$

$$EFOH_3 = \frac{1}{2} \times \frac{POR}{MDC} \times H_3$$

$$EFOH = EFOH_1 + EFOH_2 + EFOH_3$$

Figure 3
Equivalent Scheduled Outage Hours Illustration



$$ESOH = ESOH_1 + ESOH_2 + ESOH_3$$

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

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: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support of Direct Testimony

July 18, 2006

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary All MW Sizes 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	33.93	72.34	84.24	84.39	87.45	84.80	4.32	6.11	5.95	8.75	3.80	98.16	494.95
2001	35.17	69.94	81.66	83.35	87.32	84.68	4.59	6.35	6.09	8.75	3.93	98.15	482.05
2002	35.98	71.36	82.76	83.80	87.23	84.38	4.97	6.97	6.71	8.45	4.33	97.39	380.56
2003	37.02	73.04	84.16	85.17	87.66	84.91	4.60	6.54	6.37	8.29	4.06	97.01	567.09
2004	37.89	72.98	83.34	85.27	88.34	85.71	4.33	6.16	5.94	7.89	3.77	96.18	558.34
2000-04		71.95	83.24	84.41	87.60	84.90	4.56	6.43	6.21	8.43	3.98	97.40	486.31

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	831.83	799.92	834.33	797.92	828.33	4,092.33
Maximum Capacity (MW)	GROSS:	340	330	335	336	339	336
	NET:	320	313	317	318	321	318
Dependable Capacity (MW)	GROSS:	338	329	333	335	337	335
	NET:	319	311	316	317	319	317
Actual Generation (MWh)	GROSS:	2,177,943	2,044,462	2,110,414	2,169,751	2,188,441	2,138,612
	NET:	2,035,887	1,915,703	1,983,482	2,037,557	2,055,148	2,005,935
Attempted Unit Starts	:	15.23	15.12	19.56	13.40	13.63	15.41
Actual Unit Starts	:	14.95	14.84	19.05	13.00	13.11	15.01
Service Hours	:	7,399.56	7,153.62	7,249.61	7,372.15	7,319.84	7,299.44
Reserve Shutdown Hours	:	271.89	474.74	380.01	278.84	422.36	365.40
Number of Occurrences	:	4.62	4.63	5.28	3.76	4.35	4.54
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,681.56	7,649.30	7,641.14	7,678.69	7,758.60	7,682.05
Forced Outage Hours	:	334.15	344.14	378.88	355.31	331.20	348.75
Number of Occurrences	:	8.74	8.72	9.37	9.28	8.82	8.98
Planned Outages:							
Planned Outage Hours	:	590.36	603.48	556.12	570.08	541.48	572.09
Number of Occurrences	:	3.41	7.27	2.48	6.03	4.12	4.63
Planned Outage Ext. Hours	:	5.92	14.55	11.52	8.76	5.47	9.21
Number of Occurrences	:	0.66	0.06	0.07	0.39	0.05	0.25
Maintenance Outages:							
Maintenance Outage Hours	:	171.33	146.75	170.96	146.62	144.84	156.27

Number of Occurrences	:	3.57	3.21	2.53	2.27	3.59	3.04
Maintenance Outage Ext. Hours	:	0.85	2.09	1.51	0.62	1.46	1.31
Number of Occurrences	:	0.02	0.01	0.01	0.02	0.02	0.02
TOTAL UNAVAILABLE HOURS	:	1,102.43	1,110.97	1,118.95	1,081.33	1,024.44	1,087.57
TOTAL PERIOD HOURS	:	8,783.94	8,760.22	8,760.00	8,759.94	8,782.94	8,769.54
Equiv. Forced Hours	:	138.55	132.47	152.83	150.34	140.46	142.96
Equiv. Scheduled Hours	:	57.38	55.23	58.27	46.57	55.01	54.55
Equiv. Forced Hours During RS	:	2.91	2.71	3.97	3.59	5.41	3.73
Equiv. Seasonal Derated Hours	:	37.12	43.02	38.62	44.03	35.49	39.60
TOTAL EQUIVALENT DERATED HOURS	:	195.93	187.70	211.10	196.92	195.47	197.51

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 001-099 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	43.35	55.68	75.78	71.65	88.00	86.08	3.71	5.50	5.04	9.08	2.92	99.06	316.97
2001	43.18	54.65	73.49	72.53	88.99	87.00	3.76	5.51	4.99	8.14	2.87	99.02	301.99
2002	44.06	52.54	72.40	71.40	87.22	84.47	5.54	7.85	6.99	8.54	4.24	99.20	269.31
2003	44.62	56.75	76.49	73.38	87.85	85.40	4.24	6.28	5.86	8.77	3.39	98.15	370.62
2004	45.41	55.49	74.26	73.75	88.93	86.08	5.36	7.88	7.11	6.87	4.20	97.44	398.46
2000-04		55.00	74.46	72.54	88.19	85.80	4.53	6.61	6.02	8.28	3.53	98.67	324.83

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	138.58	138.08	142.92	133.50	138.08	691.17
Maximum Capacity (MW)	GROSS:	68	68	68	70	69	68
	NET:	64	64	64	66	65	65
Dependable Capacity (MW)	GROSS:	68	67	68	69	68	68
	NET:	64	64	64	65	65	64
Actual Generation (MWh)	GROSS:	337,556	328,732	318,567	352,253	340,031	335,200
	NET:	313,451	305,639	295,964	326,824	316,002	311,367
Attempted Unit Starts	:	21.20	21.53	23.74	18.42	16.79	20.37
Actual Unit Starts	:	21.00	21.32	23.55	18.08	16.36	20.10
Service Hours	:	6,656.33	6,438.48	6,342.21	6,700.89	6,518.80	6,528.99
Reserve Shutdown Hours	:	1,064.48	1,355.09	1,294.07	946.52	1,273.69	1,189.03
Number of Occurrences	:	13.41	13.60	13.84	11.81	10.85	12.72
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,729.73	7,796.59	7,639.87	7,695.54	7,805.92	7,733.13
Forced Outage Hours	:	256.77	251.76	371.72	296.78	368.90	309.67
Number of Occurrences	:	7.19	8.83	6.86	12.82	6.34	8.37
Planned Outages:							
Planned Outage Hours	:	623.85	567.45	553.07	539.03	438.89	544.61
Number of Occurrences	:	5.15	1.04	1.29	1.16	2.93	2.32
Planned Outage Ext. Hours	:	1.11	2.91	13.93	1.87	0.87	4.22
Number of Occurrences	:	0.01	0.02	0.04	0.03	0.01	0.02
Maintenance Outages:							
Maintenance Outage Hours	:	172.77	142.85	181.18	227.23	163.63	177.22

Number of Occurrences	:	3.17	2.83	2.46	2.09	7.77	3.67
Maintenance Outage Ext. Hours	:	0.07	0.00	0.00	0.18	0.00	0.05
Number of Occurrences	:	0.01	0.00	0.00	0.01	0.00	0.00
TOTAL UNAVAILABLE HOURS	:	1,054.16	964.90	1,119.81	1,065.01	972.27	1,035.64
TOTAL PERIOD HOURS	:	8,783.73	8,761.33	8,759.55	8,760.36	8,777.98	8,768.59
Equiv. Forced Hours	:	123.95	117.08	155.76	143.25	176.00	143.28
Equiv. Scheduled Hours	:	21.64	25.40	31.84	16.49	37.73	26.72
Equiv. Forced Hours During RS	:	6.99	4.58	7.44	4.86	23.13	9.42
Equiv. Seasonal Derated Hours	:	23.26	31.52	52.98	54.77	36.30	39.75
TOTAL EQUIVALENT DERATED HOURS	:	145.59	142.48	187.60	159.74	213.73	170.00

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 100-199 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	41.20	67.55	85.69	78.67	88.40	85.21	3.94	5.58	5.46	8.09	3.52	98.91	553.85
2001	42.80	63.22	81.28	77.25	88.05	84.83	4.27	6.24	5.93	8.32	3.63	98.63	493.75
2002	43.75	65.13	83.41	77.57	88.41	85.16	4.40	6.34	6.08	7.75	3.84	98.27	347.61
2003	44.86	67.12	84.66	78.95	88.54	85.22	4.45	6.69	6.48	7.51	3.95	97.99	584.39
2004	45.92	65.13	82.83	78.21	89.79	86.84	3.47	5.32	5.07	7.23	2.98	98.68	513.09
2000-04		65.64	83.57	78.14	88.64	85.45	4.11	6.03	5.80	7.78	3.58	98.51	482.49

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	228.08	226.75	228.00	224.25	226.00	1,133.08
Maximum Capacity (MW)	GROSS:	149	147	148	148	147	148
	NET:	140	138	139	139	138	139
Dependable Capacity (MW)	GROSS:	148	146	147	146	146	147
	NET:	139	137	138	138	137	138
Actual Generation (MWh)	GROSS:	892,709	822,697	851,066	874,751	849,461	858,139
	NET:	830,508	763,572	792,302	814,537	789,872	798,159
Attempted Unit Starts	:	13.74	14.62	21.39	12.95	14.37	15.42
Actual Unit Starts	:	13.59	14.42	21.02	12.69	14.18	15.19
Service Hours	:	7,526.82	7,119.82	7,306.84	7,415.96	7,275.68	7,329.08
Reserve Shutdown Hours	:	228.48	581.62	433.36	330.18	596.91	433.99
Number of Occurrences	:	4.11	5.22	5.76	4.53	6.42	5.21
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,765.14	7,713.45	7,745.10	7,756.14	7,887.37	7,773.36
Forced Outage Hours	:	308.89	317.93	336.31	345.62	261.63	314.06
Number of Occurrences	:	7.61	7.28	7.65	7.19	9.49	7.84
Planned Outages:							
Planned Outage Hours	:	522.11	535.25	470.71	499.57	474.06	500.35
Number of Occurrences	:	4.50	3.41	1.15	2.31	3.45	2.97
Planned Outage Ext. Hours	:	8.90	21.31	5.91	7.73	2.17	9.21
Number of Occurrences	:	1.16	0.07	0.05	0.07	0.04	0.28
Maintenance Outages:							
Maintenance Outage Hours	:	177.81	171.81	201.87	149.85	155.47	171.46

Number of Occurrences :	5.42	4.00	2.94	2.65	2.89	3.58
Maintenance Outage Ext. Hours :	1.44	0.56	0.20	0.87	3.38	1.29
Number of Occurrences :	0.05	0.01	0.02	0.03	0.04	0.03
TOTAL UNAVAILABLE HOURS :	1,018.95	1,046.47	1,015.00	1,003.62	896.68	996.24
TOTAL PERIOD HOURS :	8,784.05	8,759.92	8,760.04	8,759.75	8,784.00	8,769.57
Equiv. Forced Hours :	128.59	146.33	148.57	174.05	139.39	147.31
Equiv. Scheduled Hours :	98.35	85.64	85.40	69.71	84.07	84.69
Equiv. Forced Hours During RS :	3.69	5.70	6.01	9.32	5.09	5.95
Equiv. Seasonal Derated Hours :	53.52	50.44	50.94	47.55	36.31	47.77
TOTAL EQUIVALENT DERATED HOURS :	226.94	231.98	233.97	243.76	223.46	232.00

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 200-299 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	36.77	72.70	86.99	83.70	88.11	85.61	4.05	5.39	5.34	8.23	3.67	98.38	600.73
2001	38.17	69.09	84.35	81.68	88.93	86.07	4.28	5.64	5.46	7.30	3.77	99.39	562.75
2002	39.13	71.13	86.64	82.15	88.15	85.72	4.37	5.67	5.60	7.89	3.96	98.80	513.52
2003	40.35	70.61	85.75	82.34	86.96	84.10	4.98	6.44	6.37	8.55	4.50	98.78	616.18
2004	41.46	71.00	86.25	82.18	88.75	85.90	4.12	5.42	5.32	7.55	3.71	93.99	663.43
2000-04		70.91	86.00	82.41	88.18	85.49	4.36	5.71	5.61	7.90	3.92	97.94	586.92

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	110.25	110.58	113.00	110.25	114.00	558.08
Maximum Capacity (MW)	GROSS:	249	245	244	245	245	246
	NET:	232	231	229	231	231	231
Dependable Capacity (MW)	GROSS:	246	243	243	243	243	243
	NET:	230	229	229	229	228	229
Actual Generation (MWh)	GROSS:	1,597,401	1,502,421	1,529,589	1,530,018	1,541,220	1,540,063
	NET:	1,480,626	1,398,810	1,429,684	1,429,927	1,437,612	1,435,298
Attempted Unit Starts	:	12.93	13.21	14.96	12.34	12.15	13.12
Actual Unit Starts	:	12.72	13.13	14.78	12.19	11.42	12.85
Service Hours	:	7,641.34	7,388.97	7,589.77	7,511.20	7,576.34	7,541.91
Reserve Shutdown Hours	:	79.97	362.16	123.49	97.76	185.45	169.76
Number of Occurrences	:	1.56	3.40	2.12	1.96	2.81	2.37
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,739.10	7,790.11	7,721.81	7,617.31	7,795.74	7,733.21
Forced Outage Hours	:	322.20	330.45	346.89	393.80	325.61	343.68
Number of Occurrences	:	8.98	8.38	8.28	8.54	8.57	8.55
Planned Outages:							
Planned Outage Hours	:	544.74	470.88	508.92	611.26	528.78	532.73
Number of Occurrences	:	5.66	15.06	1.19	3.60	8.45	6.78
Planned Outage Ext. Hours	:	3.69	12.01	6.78	15.35	3.28	8.18
Number of Occurrences	:	2.37	0.05	0.06	0.07	0.05	0.52
Maintenance Outages:							
Maintenance Outage Hours	:	174.07	156.40	171.99	122.10	130.65	151.01

Number of Occurrences	:	2.71	4.77	2.59	2.46	4.53	3.42
Maintenance Outage Ext. Hours	:	0.00	0.00	3.79	0.16	0.11	0.82
Number of Occurrences	:	0.00	0.00	0.04	0.02	0.01	0.01
TOTAL UNAVAILABLE HOURS	:	1,044.54	969.75	1,038.30	1,142.56	988.38	1,036.35
TOTAL PERIOD HOURS	:	8,783.66	8,759.79	8,760.03	8,759.76	8,784.00	8,769.49
Equiv. Forced Hours	:	107.17	105.00	103.49	115.00	102.92	106.67
Equiv. Scheduled Hours	:	55.55	62.61	73.69	60.81	66.52	63.90
Equiv. Forced Hours During RS	:	0.12	1.64	0.16	0.63	0.27	0.56
Equiv. Seasonal Derated Hours	:	56.34	83.35	35.16	74.37	80.62	65.93
TOTAL EQUIVALENT DERATED HOURS	:	162.71	167.61	177.18	175.81	169.44	170.57

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 300-399 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	29.61	68.00	83.79	80.76	85.62	83.04	6.26	8.21	8.08	8.79	5.59	97.51	375.30
2001	30.50	68.55	85.03	80.48	86.24	83.82	4.22	6.03	5.96	10.00	3.75	95.26	553.40
2002	31.44	68.34	84.13	80.78	85.60	82.82	5.53	7.56	7.47	9.48	4.92	93.36	440.56
2003	32.13	72.47	86.77	83.23	88.18	86.00	3.82	5.31	5.26	8.38	3.44	93.83	632.88
2004	33.94	71.90	86.31	83.18	87.31	84.96	4.24	6.08	6.03	8.87	3.83	93.81	640.86
2000-04		69.87	85.20	81.72	86.59	84.12	4.82	6.65	6.58	9.09	4.32	94.92	506.59 -

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	73.08	68.00	75.67	71.00	76.83	364.58
Maximum Capacity (MW)	GROSS:	357	359	356	359	358	358
	NET:	335	338	336	337	336	336
Dependable Capacity (MW)	GROSS:	355	358	355	358	356	356
	NET:	333	337	334	336	335	335
Actual Generation (MWh)	GROSS:	2,160,648	2,191,702	2,164,181	2,305,766	2,283,857	2,221,399
	NET:	2,000,754	2,030,011	2,009,644	2,141,815	2,119,882	2,060,632
Attempted Unit Starts	:	20.11	14.13	17.92	12.80	12.61	15.54
Actual Unit Starts	:	19.61	13.46	16.73	12.01	11.83	14.75
Service Hours	:	7,359.61	7,448.78	7,370.56	7,600.85	7,581.38	7,472.23
Reserve Shutdown Hours	:	138.35	98.47	119.74	73.85	77.36	101.63
Number of Occurrences	:	7.21	1.41	5.92	1.07	1.04	3.37
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,520.67	7,554.63	7,499.58	7,724.56	7,668.66	7,593.52
Forced Outage Hours	:	491.23	328.39	431.18	301.60	336.07	378.77
Number of Occurrences	:	11.10	9.09	10.12	9.01	8.72	9.61
Planned Outages:							
Planned Outage Hours	:	561.30	682.51	641.09	575.10	625.92	616.78
Number of Occurrences	:	1.23	1.25	1.19	15.66	4.83	4.79
Planned Outage Ext. Hours	:	12.43	28.05	6.49	7.36	4.18	11.38
Number of Occurrences	:	0.08	0.09	0.05	0.07	0.08	0.07
Maintenance Outages:							
Maintenance Outage Hours	:	195.19	143.57	182.81	151.07	146.88	164.22

Number of Occurrences	:	3.78	2.87	2.75	2.68	2.55	2.92
Maintenance Outage Ext. Hours	:	2.85	21.74	0.17	0.44	1.83	5.13
Number of Occurrences	:	0.03	0.06	0.01	0.01	0.05	0.03
TOTAL UNAVAILABLE HOURS	:	1,262.92	1,205.47	1,261.73	1,035.54	1,115.07	1,176.52
TOTAL PERIOD HOURS	:	8,783.51	8,760.00	8,761.16	8,760.00	8,783.69	8,769.95
Equiv. Forced Hours	:	153.74	140.57	159.13	118.04	145.29	143.67
Equiv. Scheduled Hours	:	39.37	37.60	51.98	43.21	44.09	43.40
Equiv. Forced Hours During RS	:	5.38	0.76	8.89	0.62	0.49	3.29
Equiv. Seasonal Derated Hours	:	33.44	33.70	32.44	29.88	16.59	29.04
TOTAL EQUIVALENT DERATED HOURS	:	193.12	178.17	211.11	161.25	189.38	187.07

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 400-599 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	23.67	74.79	86.84	86.01	87.29	84.36	4.21	6.40	6.37	8.90	3.82	95.89	584.10
2001	24.28	71.87	83.90	85.46	85.15	82.77	5.72	7.56	7.49	9.76	5.09	97.43	539.27
2002	25.53	72.72	85.11	85.25	86.10	83.12	5.48	7.91	7.85	8.96	4.93	95.49	374.86
2003	26.45	74.30	85.91	86.38	86.93	84.17	5.25	7.49	7.45	8.31	4.76	95.49	612.38
2004	27.56	74.83	86.35	86.62	87.25	84.89	4.57	6.48	6.43	8.62	4.14	95.22	585.27
2000-04		73.72	85.66	85.94	86.56	83.87	5.02	7.15	7.10	8.91	4.53	95.88	520.60 -

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	160.75	139.50	152.92	137.00	145.42	735.58
Maximum Capacity (MW)	GROSS:	537	537	537	538	542	538
	NET:	509	510	510	511	512	510
Dependable Capacity (MW)	GROSS:	534	534	534	535	537	535
	NET:	507	507	508	509	511	508
Actual Generation (MWh)	GROSS:	3,555,527	3,412,555	3,446,684	3,537,069	3,575,411	3,506,279
	NET:	3,344,281	3,209,305	3,249,402	3,327,038	3,365,369	3,299,917
Attempted Unit Starts	:	13.62	13.99	20.83	12.87	13.61	15.05
Actual Unit Starts	:	13.06	13.63	19.89	12.29	12.96	14.43
Service Hours	:	7,628.29	7,350.27	7,456.00	7,526.12	7,585.16	7,512.19
Reserve Shutdown Hours	:	33.51	72.47	53.68	35.60	67.43	52.19
Number of Occurrences	:	1.88	0.82	2.49	0.66	1.45	1.50
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,667.37	7,459.64	7,542.55	7,615.27	7,663.72	7,591.60
Forced Outage Hours	:	335.49	445.61	432.26	417.16	363.30	397.20
Number of Occurrences	:	9.74	10.44	14.38	10.77	10.14	11.11
Planned Outages:							
Planned Outage Hours	:	599.61	697.16	591.17	582.79	602.16	613.73
Number of Occurrences	:	1.23	14.13	7.87	15.97	1.37	7.83
Planned Outage Ext. Hours	:	7.24	13.23	25.72	14.17	9.49	13.95
Number of Occurrences	:	0.07	0.08	0.14	0.11	0.08	0.10
Maintenance Outages:							
Maintenance Outage Hours	:	173.61	144.15	167.60	129.09	143.34	152.50

Number of Occurrences	:	2.97	2.41	2.57	1.97	2.19	2.44
Maintenance Outage Ext. Hours	:	1.03	0.49	0.75	1.63	2.00	1.17
Number of Occurrences	:	0.02	0.02	0.01	0.04	0.02	0.02
TOTAL UNAVAILABLE HOURS	:	1,116.90	1,300.58	1,217.45	1,144.82	1,120.31	1,178.51
TOTAL PERIOD HOURS	:	8,784.22	8,760.24	8,759.94	8,759.99	8,783.88	8,770.05
Equiv. Forced Hours	:	173.93	143.66	191.49	178.08	151.80	168.24
Equiv. Scheduled Hours	:	51.53	33.24	41.11	31.36	34.62	38.79
Equiv. Forced Hours During RS	:	1.25	0.09	1.25	0.09	0.30	0.63
Equiv. Seasonal Derated Hours	:	31.74	32.18	28.56	32.30	20.35	29.02
TOTAL EQUIVALENT DERATED HOURS	:	225.46	176.90	232.60	209.44	186.42	207.03

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 600-799 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	23.59	74.70	85.57	87.27	85.84	83.28	4.99	7.17	7.15	9.67	4.49	98.66	598.44
2001	24.44	73.52	84.98	86.53	85.70	83.20	5.37	7.16	7.13	9.47	4.83	95.61	610.18
2002	25.44	74.47	86.38	86.14	86.80	84.06	4.91	6.91	6.89	8.74	4.47	95.74	503.13
2003	26.44	77.27	87.98	87.77	88.32	85.74	4.15	6.05	6.04	7.87	3.81	93.48	736.07
2004	26.73	75.23	85.82	87.63	86.07	83.62	4.90	6.71	6.70	9.51	4.42	92.99	709.84
2000-04		75.04	86.14	87.08	86.54	83.97	4.86	6.79	6.77	9.06	4.40	95.37	621.76

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	84.08	85.00	85.00	84.92	91.00	430.00
Maximum Capacity (MW)	GROSS:	730	728	731	731	728	730
	NET:	690	692	693	694	692	692
Dependable Capacity (MW)	GROSS:	729	726	727	726	724	726
	NET:	689	689	691	692	689	690
Actual Generation (MWh)	GROSS:	4,819,628	4,723,705	4,792,021	4,972,734	4,845,906	4,831,006
	NET:	4,527,860	4,455,290	4,522,521	4,697,036	4,571,689	4,555,144
Attempted Unit Starts	:	12.73	12.76	15.71	11.20	11.42	12.74
Actual Unit Starts	:	12.56	12.20	15.04	10.47	10.62	12.15
Service Hours	:	7,516.35	7,444.20	7,567.00	7,706.65	7,538.52	7,554.37
Reserve Shutdown Hours	:	20.04	23.65	23.86	13.14	19.98	20.13
Number of Occurrences	:	0.42	0.46	0.47	0.31	0.45	0.42
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,540.47	7,507.51	7,603.44	7,737.11	7,560.66	7,589.51
Forced Outage Hours	:	394.63	422.82	391.14	333.42	388.08	386.04
Number of Occurrences	:	10.06	10.18	10.36	8.89	9.58	9.81
Planned Outages:							
Planned Outage Hours	:	714.83	733.71	657.31	600.28	694.77	680.32
Number of Occurrences	:	1.38	13.41	1.54	4.59	1.45	4.44
Planned Outage Ext. Hours	:	3.09	5.33	3.12	3.38	16.92	6.53
Number of Occurrences	:	0.04	0.04	0.02	3.04	0.04	0.63
Maintenance Outages:							
Maintenance Outage Hours	:	131.29	90.74	97.36	85.75	123.65	105.96

Number of Occurrences	:	2.03	1.59	1.61	1.60	1.71	1.71
Maintenance Outage Ext. Hours	:	0.00	0.00	7.78	0.02	0.00	1.54
Number of Occurrences	:	0.00	0.00	0.01	0.01	0.00	0.00
TOTAL UNAVAILABLE HOURS	:	1,243.69	1,252.61	1,156.68	1,022.79	1,223.40	1,180.34
TOTAL PERIOD HOURS	:	8,784.17	8,760.00	8,760.06	8,759.84	8,784.01	8,769.79
Equiv. Forced Hours	:	172.25	140.12	158.68	153.22	143.99	153.48
Equiv. Scheduled Hours	:	37.30	52.22	57.97	47.95	44.71	48.01
Equiv. Forced Hours During RS	:	0.00	0.00	0.00	0.01	0.00	0.00
Equiv. Seasonal Derated Hours	:	15.80	27.13	22.94	25.35	26.47	23.60
TOTAL EQUIVALENT DERATED HOURS	:	209.54	192.34	216.65	201.17	188.70	201.48

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 800-999 MW 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	21.80	76.65	86.96	88.18	87.21	85.87	3.06	3.96	3.95	10.05	2.74	100.00	636.54
2001	21.25	72.03	85.37	84.22	86.10	83.70	2.96	4.34	4.30	11.29	2.61	100.00	702.20
2002	23.80	76.16	85.99	88.58	86.01	84.23	4.00	5.68	5.68	10.40	3.58	99.72	533.47
2003	24.80	78.20	86.65	90.07	86.71	85.54	3.02	4.10	4.10	10.59	2.70	99.56	839.64
2004	25.80	80.94	89.28	90.64	90.28	89.43	2.87	3.47	3.46	7.08	2.64	93.50	1,048.44
2000-04		77.00	86.91	88.54	87.31	85.84	3.19	4.30	4.29	9.82	2.86	98.89	715.03

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	25.00	20.00	25.00	25.00	25.00	120.00
Maximum Capacity (MW)	GROSS:	887	874	880	882	884	882
	NET:	838	835	840	840	842	839
Dependable Capacity (MW)	GROSS:	887	874	879	882	884	882
	NET:	838	835	839	840	842	839
Actual Generation (MWh)	GROSS:	6,051,392	5,651,873	5,917,696	6,096,092	6,309,961	6,020,133
	NET:	5,644,038	5,268,303	5,601,152	5,753,094	5,986,926	5,666,636
Attempted Unit Starts	:	12.00	10.65	14.16	9.08	8.00	10.78
Actual Unit Starts	:	12.00	10.65	14.12	9.04	7.48	10.66
Service Hours	:	7,638.48	7,478.40	7,532.56	7,590.36	7,842.32	7,622.18
Reserve Shutdown Hours	:	19.40	61.65	0.36	1.12	10.72	16.86
Number of Occurrences	:	0.32	0.45	0.04	0.04	0.16	0.19
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,660.29	7,542.45	7,534.84	7,595.72	7,930.19	7,657.29
Forced Outage Hours	:	240.99	228.50	313.96	236.28	231.53	251.16
Number of Occurrences	:	8.00	7.20	7.96	6.32	6.72	7.24
Planned Outages:							
Planned Outage Hours	:	760.84	832.00	770.16	795.16	527.12	733.10
Number of Occurrences	:	2.28	1.35	1.52	1.44	21.48	5.79
Planned Outage Ext. Hours	:	0.00	35.02	22.06	11.62	3.41	13.56
Number of Occurrences	:	0.00	0.10	0.04	0.12	0.04	0.06
Maintenance Outages:							
Maintenance Outage Hours	:	121.92	122.15	119.08	121.28	91.52	114.90

Number of Occurrences	:	1.84	2.40	1.92	2.28	1.44	1.96
Màintenance Outage Ext. Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Number of Occurrences	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL UNAVAILABLE HOURS	:	1,123.67	1,217.50	1,225.20	1,164.40	853.73	1,112.71
TOTAL PERIOD HOURS	:	8,784.00	8,760.00	8,760.00	8,760.00	8,783.84	8,769.97
Equiv. Forced Hours	:	71.11	105.62	131.49	84.38	48.41	87.48
Equiv. Scheduled Hours	:	45.68	104.24	24.81	17.89	24.01	40.79
Equiv. Forced Hours During RS	:	0.00	0.00	0.00	0.00	1.03	0.21
Equiv. Seasonal Derated Hours	:	0.94	0.46	0.38	0.35	2.20	0.88
TOTAL EQUIVALENT DERATED HOURS	:	116.79	209.86	156.30	102.27	72.42	128.27

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary 1000 MW Plus 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
2000	22.58	70.27	82.03	85.06	82.09	79.67	7.84	9.41	9.41	10.93	6.98	98.55	622.27
2001	23.58	71.11	83.27	85.25	84.11	81.91	7.29	8.76	8.70	9.34	6.55	100.00	653.03
2002	24.51	75.57	86.09	87.67	86.30	84.02	7.55	9.19	9.18	6.67	7.03	98.40	719.44
2003	25.58	70.13	77.75	89.39	77.85	75.74	11.07	12.41	12.41	12.46	9.68	96.73	698.56
2004	26.58	75.26	83.06	90.23	83.17	81.05	7.79	9.12	9.11	9.82	7.02	93.50	603.96
2000-04		72.46	82.43	87.50	82.69	80.47	8.29	9.76	9.74	9.85	7.45	97.35	656.54 -

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	12.00	12.00	11.83	12.00	12.00	59.83
Maximum Capacity (MW)	GROSS:	1,339	1,307	1,308	1,308	1,309	1,314
	NET:	1,239	1,238	1,239	1,238	1,240	1,239
Dependable Capacity (MW)	GROSS:	1,335	1,303	1,304	1,304	1,306	1,311
	NET:	1,235	1,234	1,235	1,234	1,236	1,235
Actual Generation (MWh)	GROSS:	8,265,592	8,139,824	8,644,884	8,037,430	8,666,797	8,350,087
	NET:	7,648,486	7,714,140	8,196,671	7,608,617	8,196,566	7,871,994
Attempted Unit Starts	:	11.75	11.17	10.65	10.08	12.92	11.31
Actual Unit Starts	:	11.58	11.17	10.48	9.75	12.08	11.01
Service Hours	:	7,205.92	7,294.33	7,539.72	6,811.00	7,295.83	7,228.50
Reserve Shutdown Hours	:	4.08	54.92	3.97	3.75	8.33	15.04
Number of Occurrences	:	0.08	0.67	0.17	0.17	0.25	0.27
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,210.88	7,368.21	7,557.73	6,820.00	7,305.37	7,251.59
Forced Outage Hours	:	613.29	573.75	615.62	848.16	616.71	653.61
Number of Occurrences	:	10.50	8.17	9.13	9.25	10.08	9.43
Planned Outages:							
Planned Outage Hours	:	745.92	688.75	513.63	997.25	703.67	730.45
Number of Occurrences	:	1.00	0.92	1.77	1.25	2.08	1.40
Planned Outage Ext. Hours	:	0.17	14.34	22.16	22.63	18.29	15.50
Number of Occurrences	:	0.08	0.17	0.17	0.17	0.08	0.13
Maintenance Outages:							
Maintenance Outage Hours	:	214.17	114.87	48.51	71.83	140.33	118.14

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Number of Occurrences	1.83	2.50	0.93	1.17	1.92	1.67
Maintenance Outage Ext. Hours	0.00	0.00	0.00	0.00	0.00	0.00
Number of Occurrences	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL UNAVAILABLE HOURS	1,573.04	1,391.71	1,199.91	1,939.83	1,478.63	1,517.51
TOTAL PERIOD HOURS	8,784.00	8,760.00	8,757.63	8,759.92	8,784.00	8,769.14
Equiv. Forced Hours	122.75	115.37	133.85	102.68	104.80	115.84
Equiv. Scheduled Hours	61.46	51.07	42.23	61.48	57.24	54.73
Equiv. Forced Hours During RS	0.00	0.00	0.00	0.00	0.00	0.00
Equiv. Seasonal Derated Hours	28.15	26.09	23.91	20.81	24.25	24.65
TOTAL EQUIVALENT DERATED HOURS	184.21	166.44	176.08	164.16	162.04	170.57

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support of
Direct Testimony

July 18, 2006

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary All MW Sizes

Year	Number of Util.	Units	CAPACITY WEIGHTED STATISTICS WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	UNIT STARTS Attempts	Actual	Capacity (Net, MW) Max	Dep	Net Generation MWHr/U-Yr
1982	102	784	72.03	80.01	74.90	12.95	7.02	8.88	13.66	21.64	21.50	294	292	1,375,631
1983	107	800	72.78	80.95	76.55	12.60	6.44	8.13	12.20	21.50	21.35	297	295	1,416,915
1984	107	820	73.60	80.96	77.20	12.23	6.80	8.45	11.92	20.12	19.90	300	298	1,474,323
1985	113	832	73.83	81.19	77.93	12.81	6.14	7.68	10.67	20.05	19.68	302	300	1,498,515
1986	117	835	73.18	81.75	78.56	12.50	5.76	7.29	10.38	20.56	20.37	305	303	1,466,148
1987	122	841	74.50	82.00	79.15	12.50	5.50	6.88	9.57	18.93	18.72	306	305	1,550,729
1988	125	852	75.99	83.18	80.11	11.97	4.84	5.99	9.00	20.15	19.93	308	307	1,617,112
1989	124	866	75.95	83.40	80.42	11.53	5.05	6.23	9.00	24.14	23.90	306	305	1,607,052
1990	124	869	77.22	83.92	81.01	11.42	4.65	5.69	8.18	18.69	18.46	309	308	1,623,053
1991	126	870	76.48	84.10	81.34	11.65	4.25	5.27	7.64	17.99	17.80	312	310	1,605,975
1992	126	871	76.63	84.45	81.96	11.77	3.78	4.70	6.72	17.78	17.48	314	313	1,644,012
1993	126	868	78.71	84.24	81.44	11.32	4.44	5.34	7.74	18.93	18.71	314	313	1,703,834
1994	128	876	78.92	84.53	81.61	11.38	4.09	4.92	7.37	19.24	18.91	312	311	1,658,537
1995	125	873	79.65	85.39	82.87	10.35	4.26	5.08	7.20	19.79	19.47	313	312	1,683,922
1996	124	872	82.36	86.32	83.59	9.54	4.14	4.79	6.94	20.08	19.59	315	314	1,763,748
1997	125	875	83.88	86.84	84.18	8.72	4.45	5.04	7.20	17.16	16.62	315	314	1,817,014
1998	127	869	84.49	86.81	83.90	8.73	4.46	5.01	7.42	15.95	15.58	317	316	1,878,194
1999	126	884	83.70	85.86	83.15	9.79	4.35	4.94	7.00	16.51	15.96	314	313	1,855,818
2000	122	838	85.71	86.85	84.26	9.08	4.08	4.55	6.39	15.23	14.95	320	319	2,035,887
2001	120	806	83.91	86.35	83.84	9.26	4.39	4.97	6.67	15.12	14.84	313	311	1,915,703
2002	123	836	85.16	86.80	84.11	8.66	4.54	5.06	7.04	19.56	19.05	317	316	1,983,482
2003	120	800	85.76	87.13	84.59	8.55	4.34	4.81	6.65	13.40	13.00	318	317	2,037,557
2004	126	831	85.59	87.53	85.17	8.47	4.01	4.48	6.16	13.63	13.11	321	319	2,055,148
2000-2004:			85.24	86.94	84.40	8.80	4.27	4.77	6.58	15.41	15.01	318	317	2,005,935
1995-2004:			84.00	86.58	83.96	9.12	4.30	4.87	6.87	16.69	16.26	316	315	1,899,719
1982-2004:			79.28	84.46	81.50	10.73	4.82	5.73	8.22	18.53	18.21	311	309	1,708,883

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	19.05	771	54.03	53.48	75.00	74.25	67.92	81.79	77.39	12.06	6.12	8.26	12.26	99.35	276.69
1983	19.79	788	54.91	54.54	75.48	74.93	67.16	82.17	78.25	12.12	5.68	7.80	11.43	99.30	275.54
1984	20.38	803	56.32	55.96	76.56	76.03	68.63	82.59	78.92	11.69	5.68	7.64	11.04	98.91	302.89
1985	21.00	816	57.01	56.64	77.23	76.73	69.01	82.38	79.12	12.15	5.53	7.42	10.41	98.15	307.20
1986	21.58	829	55.32	54.89	75.62	75.02	67.72	82.54	79.61	12.25	5.20	7.13	10.01	99.08	291.16
1987	22.47	834	58.22	57.80	78.18	77.59	69.44	82.68	79.93	12.38	4.93	6.62	9.28	98.89	324.97
1988	23.24	841	60.11	59.75	79.12	78.63	71.03	84.09	80.99	11.49	4.42	5.85	8.99	98.91	313.01
1989	24.37	858	60.25	59.86	79.34	78.81	70.91	84.17	81.23	11.01	4.77	6.30	9.19	99.01	259.90
1990	25.23	860	60.32	59.92	78.11	77.60	71.85	84.67	81.81	11.06	4.27	5.61	8.21	98.77	340.95
1991	26.09	864	59.27	58.84	77.51	76.94	70.20	84.87	82.32	11.37	3.74	5.06	7.43	98.94	345.48
1992	27.07	863	60.21	59.55	78.59	77.72	70.52	85.37	83.03	11.22	3.42	4.62	6.66	98.31	354.40
1993	28.09	861	62.48	61.87	79.39	78.60	74.22	85.10	82.52	10.98	3.92	5.02	7.31	98.84	347.50
1994	29.03	869	61.23	60.65	77.57	76.85	73.56	85.38	82.72	10.96	3.64	4.72	7.12	98.28	340.74
1995	29.90	869	61.95	61.36	77.79	77.04	74.16	86.23	83.86	10.00	3.77	4.84	6.96	98.38	333.65
1996	30.32	868	64.37	63.68	78.15	77.32	78.38	86.93	84.18	9.28	3.80	4.62	7.00	97.56	351.44
1997	31.29	874	66.47	65.91	79.24	78.57	80.33	87.40	84.74	8.69	3.91	4.64	6.94	96.85	423.36
1998	32.25	867	68.10	67.72	80.59	80.16	81.56	87.36	84.57	8.64	4.01	4.68	7.06	97.68	458.57
1999	33.39	874	67.87	67.51	81.11	80.66	80.62	86.26	83.58	9.67	4.06	4.80	6.87	96.67	442.22
2000	33.93	832	72.89	72.34	85.03	84.39	84.24	87.45	84.80	8.76	3.80	4.32	6.11	98.16	494.95
2001	35.17	800	70.65	69.94	84.19	83.35	81.66	87.32	84.68	8.75	3.93	4.59	6.35	98.15	482.05
2002	35.98	834	71.89	71.36	84.40	83.80	82.76	87.23	84.38	8.45	4.33	4.97	6.97	97.39	380.56
2003	37.02	798	73.63	73.04	85.85	85.17	84.16	87.66	84.91	8.30	4.06	4.60	6.54	97.01	567.09
2004	37.89	828	73.41	72.98	85.75	85.27	83.34	88.34	85.71	7.90	3.77	4.33	6.16	96.18	558.34
2000-2004:		4,092	72.51	71.95	85.05	84.41	83.24	87.60	84.90	8.43	3.98	4.56	6.43	97.40	486.31
1995-2004:		8,442	69.05	68.51	82.20	81.56	81.06	87.21	84.53	8.86	3.94	4.64	6.70	97.42	437.03
1982-2004:		19,296	63.24	62.74	79.78	79.15	74.97	85.25	82.36	10.39	4.36	5.50	7.97	98.27	360.87

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 001-099 MW

	Number of		---------- CAPACITY WEIGHTED STATISTICS -----------							-- UNIT STARTS --		Capacity (Net, MW)		Net Generation
Year	Util.	Units	WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	Attempts	Actual	Max	Dep	MWHr/U-Yr
1982	40	134	56.47	85.09	81.59	10.67	4.22	6.95	8.93	30.48	30.37	62	61	210,708
1983	41	138	51.82	83.71	80.25	12.46	3.77	6.78	9.99	29.74	29.60	62	61	196,099
1984	44	138	54.23	81.70	78.22	14.25	3.76	6.49	9.72	29.07	28.96	61	60	202,897
1985	45	140	56.06	83.75	80.76	11.71	4.49	7.41	9.57	26.45	26.28	61	60	211,545
1986	45	133	53.66	84.60	81.97	11.01	4.35	7.50	9.68	28.84	28.67	63	62	196,457
1987	45	130	55.40	83.31	80.60	12.65	3.97	6.68	8.92	27.97	27.82	63	62	209,654
1988	47	130	57.20	87.49	84.30	8.97	3.56	5.86	9.17	36.21	35.98	64	63	218,024
1989	49	138	56.29	84.61	82.24	11.85	3.53	5.89	8.42	48.28	47.96	64	64	220,901
1990	49	139	56.61	88.41	86.21	8.14	3.43	5.71	7.73	28.57	28.44	64	64	213,405
1991	48	139	53.37	88.15	86.43	9.88	1.94	3.50	5.34	26.89	26.73	65	64	197,802
1992	48	138	54.02	88.05	86.48	9.86	2.09	3.72	5.18	23.43	23.24	65	65	201,843
1993	48	138	58.38	88.11	86.33	9.34	2.55	4.18	5.63	26.75	26.50	65	65	216,001
1994	49	150	56.60	87.56	85.82	9.46	2.89	4.86	6.68	26.36	26.12	65	65	209,850
1995	47	146	56.35	88.01	86.41	9.65	2.35	4.00	5.68	25.22	25.11	66	65	209,405
1996	45	145	64.38	87.28	85.19	9.74	2.98	4.43	6.74	26.86	26.67	65	64	234,390
1997	45	145	68.41	89.46	87.42	7.73	2.81	3.95	6.02	21.45	21.21	65	65	257,423
1998	44	140	70.78	88.54	86.69	8.54	2.93	3.97	5.79	21.70	21.42	65	65	278,397
1999	47	151	69.51	86.43	84.44	10.75	2.82	3.90	5.83	22.47	22.18	64	64	266,826
2000	42	139	77.71	88.46	86.47	8.71	2.84	3.53	5.30	21.20	21.00	64	64	313,451
2001	42	141	75.35	89.53	87.42	7.58	2.89	3.70	5.41	21.53	21.32	64	64	305,639
2002	44	144	73.57	87.32	84.65	8.81	3.87	5.00	7.23	23.74	23.55	64	64	295,964
2003	42	134	77.33	88.13	85.65	8.20	3.67	4.53	6.64	18.42	18.08	66	65	326,824
2004	44	140	75.23	89.47	86.55	6.75	3.79	4.79	7.40	16.79	16.36	65	65	316,002
2000-2004:			75.82	88.57	86.14	8.01	3.42	4.31	6.40	20.37	20.10	65	64	311,367
1995-2004:			70.71	88.25	86.08	8.67	3.09	4.18	6.22	22.00	21.75	65	64	279,571
1982-2004:			62.35	86.92	84.55	9.80	3.26	4.96	7.10	26.34	26.13	64	64	240,159

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	29.32	130	39.50	38.92	69.79	68.93	53.94	85.93	82.18	10.29	3.76	6.52	8.41	99.64	155.62
1983	30.39	133	36.57	36.20	70.76	69.86	50.13	84.68	81.05	11.71	3.52	6.56	9.35	99.53	148.33
1984	31.08	131	38.00	37.66	70.19	69.45	52.15	83.59	79.96	12.58	3.54	6.36	9.15	99.62	158.17
1985	31.23	134	39.70	39.32	70.85	70.13	53.68	84.61	81.51	11.03	4.30	7.41	9.32	99.36	178.93
1986	31.81	129	36.12	35.69	67.34	66.51	51.96	85.06	82.44	10.51	4.35	7.73	9.77	99.41	158.72
1987	32.86	128	38.42	37.89	69.36	68.39	54.11	84.54	81.74	11.32	4.04	6.95	9.17	99.46	170.39
1988	33.68	126	39.39	38.91	68.89	68.03	55.27	87.43	84.09	9.07	3.50	5.96	9.48	99.36	134.91
1989	35.12	135	39.61	39.19	70.34	69.61	54.21	85.47	82.99	11.31	3.19	5.56	8.32	99.34	99.02
1990	35.86	137	38.52	38.03	67.97	67.19	53.87	88.35	86.31	8.40	3.23	5.65	7.60	99.54	165.93
1991	36.88	137	35.51	34.98	66.45	65.54	50.55	88.43	86.81	9.33	2.15	4.08	5.87	99.40	165.65
1992	38.30	135	35.68	35.22	65.97	65.20	51.18	88.49	86.92	9.54	1.97	3.70	5.15	99.19	193.43
1993	39.38	137	38.41	37.91	65.71	64.94	55.86	88.39	86.71	9.17	2.43	4.16	5.56	99.07	184.67
1994	39.33	147	37.00	36.62	65.32	64.70	53.44	87.56	85.87	9.27	3.03	5.37	7.23	99.09	179.20
1995	40.38	146	36.81	36.43	65.26	64.65	53.35	88.15	86.53	9.71	2.14	3.85	5.69	99.56	186.13
1996	38.63	144	41.72	41.30	64.76	64.15	61.65	87.40	84.88	9.90	2.71	4.20	7.43	99.29	203.05
1997	39.99	144	45.81	45.29	66.93	66.20	66.04	89.31	87.35	7.99	2.70	3.93	6.08	98.88	272.62
1998	41.27	140	49.09	48.70	69.29	68.80	68.44	88.32	86.58	8.83	2.85	4.00	5.84	98.71	279.90
1999	42.45	148	47.87	47.36	68.82	68.14	68.33	86.31	84.30	10.85	2.85	4.00	6.06	98.71	269.86
2000	43.35	139	56.43	55.68	72.56	71.65	75.78	88.00	86.08	9.08	2.92	3.71	5.50	99.06	316.97
2001	43.18	138	55.49	54.65	73.64	72.53	73.49	88.99	87.00	8.14	2.87	3.76	5.51	99.02	301.99
2002	44.06	143	53.38	52.54	72.48	71.40	72.40	87.22	84.47	8.54	4.24	5.54	7.85	99.20	269.31
2003	44.62	134	57.68	56.75	74.57	73.38	76.49	87.85	85.40	8.77	3.39	4.24	6.28	98.15	370.62
2004	45.41	138	56.36	55.49	74.89	73.75	74.26	88.93	86.08	6.87	4.20	5.36	7.88	97.44	398.46
2000-2004:		691	55.85	55.00	73.62	72.54	74.46	88.19	85.80	8.28	3.53	4.53	6.61	98.67	324.83
1995-2004:		1,413	49.90	49.25	70.52	69.66	68.88	88.04	85.86	8.89	3.08	4.28	6.43	98.86	277.62
1982-2004:		3,149	43.31	42.77	69.44	68.60	60.18	87.12	84.72	9.64	3.20	5.05	7.21	99.20	201.87

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 100-199 MW

Year	Number of Util.	Number of Units	WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	Unit Starts Attempts	Unit Starts Actual	Capacity (Net, MW) Max	Capacity (Net, MW) Dep	Net Generation MWHr/U-Yr
1982	62	229	66.19	82.02	78.76	12.05	5.87	8.14	11.22	18.32	18.22	136	135	558,385
1983	65	233	65.03	83.57	80.64	11.23	5.16	7.36	10.34	17.92	17.87	136	135	556,909
1984	67	238	65.95	84.51	81.31	10.52	4.98	7.02	10.28	16.42	16.33	137	136	577,873
1985	68	240	67.22	83.73	80.58	11.25	4.98	6.89	10.12	18.13	18.03	137	136	587,591
1986	68	242	65.01	83.92	81.38	11.68	4.40	6.34	9.21	16.65	16.59	137	136	561,771
1987	71	247	65.87	83.96	81.58	11.83	4.19	5.99	8.68	16.71	16.54	137	136	590,806
1988	72	248	67.78	84.78	81.81	11.16	4.05	5.64	8.99	17.59	17.46	137	137	615,573
1989	74	254	68.93	85.36	82.20	9.81	4.64	6.31	9.61	22.06	21.94	137	137	629,167
1990	72	249	70.24	84.73	81.63	11.19	4.08	5.49	8.49	16.61	16.48	138	137	629,675
1991	72	248	67.03	85.09	82.56	11.51	3.40	4.83	7.14	16.91	16.79	138	137	586,516
1992	73	250	68.50	86.50	84.22	10.53	2.97	4.15	6.23	16.13	15.96	138	137	603,055
1993	71	247	75.19	85.81	83.11	10.90	3.29	4.19	6.55	16.39	16.26	138	137	678,250
1994	71	245	74.68	86.80	83.95	10.39	2.81	3.62	6.16	18.42	18.28	138	137	658,575
1995	70	245	76.23	87.98	85.44	8.74	3.28	4.13	6.19	19.49	19.20	139	138	680,226
1996	69	244	80.23	88.42	85.40	8.40	3.19	3.82	6.28	18.08	17.68	139	138	703,999
1997	68	242	81.61	88.35	85.30	8.69	2.96	3.50	6.04	16.83	15.98	138	137	717,604
1998	69	243	82.79	88.41	85.46	8.08	3.51	4.07	6.35	15.04	14.88	137	137	750,126
1999	72	251	81.54	87.35	84.44	8.55	4.08	4.76	6.69	16.06	15.86	138	138	749,637
2000	66	229	85.86	88.41	85.33	8.10	3.51	3.92	5.53	13.74	13.59	140	139	830,508
2001	67	229	81.84	88.06	84.93	8.24	3.71	4.34	6.21	14.62	14.42	138	137	763,572
2002	67	228	83.97	88.36	85.17	7.81	3.82	4.36	6.28	21.39	21.02	139	138	792,302
2003	66	225	85.01	88.31	85.12	7.70	3.99	4.49	6.61	12.95	12.69	139	138	814,537
2004	66	226	83.27	89.65	86.79	7.36	2.99	3.47	5.25	14.37	14.18	138	137	789,872
2000-2004:			84.00	88.56	85.47	7.84	3.60	4.11	5.97	15.42	15.19	139	138	798,159
1995-2004:			82.18	88.32	85.33	8.18	3.50	4.09	6.15	16.29	15.98	138	138	757,867
1982-2004:			74.28	86.26	83.35	9.83	3.90	4.98	7.46	17.02	16.82	138	137	669,357

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	24.78	227	47.59	46.88	71.94	70.82	65.46	82.09	78.90	11.85	6.01	8.40	11.48	99.45	314.62
1983	25.53	231	47.15	46.74	72.63	71.87	64.02	83.61	80.67	11.13	5.23	7.55	10.58	99.72	313.83
1984	26.29	235	48.48	48.09	73.60	72.92	65.25	84.63	81.45	10.43	4.95	7.05	10.34	99.45	350.96
1985	27.24	238	49.34	48.88	73.43	72.71	66.59	83.77	80.61	11.19	4.99	6.98	10.29	99.45	323.52
1986	28.12	242	47.29	46.86	72.77	72.08	64.42	83.90	81.37	11.74	4.36	6.35	9.24	99.64	340.14
1987	29.12	245	49.73	49.31	75.55	74.86	65.12	83.66	81.32	12.09	4.24	6.11	8.81	98.98	344.94
1988	29.89	247	51.32	51.03	75.79	75.29	67.19	84.89	82.00	11.18	3.92	5.52	8.80	99.26	338.01
1989	30.94	252	52.70	52.28	76.49	75.84	68.19	85.71	82.49	9.54	4.60	6.31	9.74	99.46	272.26
1990	32.01	248	52.62	52.21	74.88	74.33	69.46	84.92	81.76	11.11	3.97	5.41	8.49	99.22	369.22
1991	33.00	247	48.90	48.45	72.96	72.27	66.43	85.47	82.89	11.26	3.28	4.70	7.10	99.29	346.58
1992	33.96	248	51.07	49.85	74.52	72.77	67.31	86.58	84.32	10.48	2.95	4.19	6.30	98.95	370.45
1993	34.97	245	57.05	56.10	75.94	74.61	74.15	85.71	83.05	10.99	3.30	4.26	6.64	99.21	399.49
1994	35.97	244	55.34	54.40	74.10	72.85	73.93	86.97	84.15	10.29	2.73	3.56	6.11	99.24	354.25
1995	36.71	244	56.90	56.00	74.67	73.45	75.04	87.91	85.39	8.85	3.24	4.14	6.28	98.51	342.36
1996	37.65	242	58.85	57.76	73.44	71.99	79.50	88.39	85.37	8.40	3.21	3.88	6.39	97.79	394.99
1997	38.65	242	60.35	59.46	73.97	72.86	80.91	88.31	85.18	8.67	3.02	3.60	6.26	94.95	443.54
1998	39.68	242	62.76	62.33	75.80	75.29	82.33	88.34	85.31	8.14	3.52	4.10	6.49	98.94	484.65
1999	40.55	246	62.26	61.86	76.36	75.86	81.27	87.58	84.62	8.27	4.13	4.83	6.80	98.75	448.57
2000	41.20	228	68.01	67.55	79.21	78.67	85.69	88.40	85.21	8.09	3.52	3.94	5.58	98.91	553.85
2001	42.80	227	63.85	63.22	77.98	77.25	81.28	88.05	84.83	8.32	3.63	4.27	6.24	98.63	493.75
2002	43.75	228	65.71	65.13	78.25	77.57	83.41	88.41	85.16	7.75	3.84	4.40	6.34	98.27	347.61
2003	44.86	224	67.69	67.12	79.63	78.95	84.66	88.54	85.22	7.51	3.95	4.45	6.69	97.99	584.39
2004	45.92	226	65.67	65.13	78.84	78.21	82.83	89.79	86.84	7.23	2.98	3.47	5.32	98.68	513.09
2000-2004:		1,133	66.19	65.64	78.79	78.14	83.57	88.64	85.45	7.78	3.58	4.11	6.03	98.51	482.49
1995-2004:		2,350	63.12	62.45	76.81	76.00	81.62	88.36	85.31	8.14	3.50	4.11	6.24	98.10	447.77
1982-2004:		5,499	56.05	55.43	75.48	74.63	73.56	86.32	83.39	9.78	3.89	5.02	7.55	98.82	383.36

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 200-299 MW

Year	Number of Util.	Number of Units	CAPACITY WEIGHTED STATISTICS WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	UNIT STARTS Attempts	UNIT STARTS Actual	Capacity (Net, MW) Max	Capacity (Net, MW) Dep	Net Generation MWHr/U-Yr
1982	44	111	76.50	84.46	80.82	10.74	4.74	5.84	8.92	17.91	17.81	229	228	1,183,661
1983	45	111	73.72	82.72	79.41	11.72	5.55	7.01	10.01	15.55	15.50	230	228	1,159,415
1984	44	110	77.42	85.22	81.54	10.28	4.50	5.49	8.58	15.01	14.98	230	229	1,216,515
1985	45	113	74.91	82.25	79.48	12.77	4.99	6.24	8.59	15.34	15.12	231	229	1,219,543
1986	47	116	74.96	83.18	80.64	12.21	4.61	5.79	7.88	15.78	15.70	232	230	1,184,719
1987	48	117	76.63	83.25	80.70	12.16	4.59	5.65	7.90	15.25	15.14	231	230	1,225,809
1988	49	117	77.39	84.18	81.77	11.03	4.80	5.84	7.86	14.57	14.47	232	230	1,268,358
1989	50	118	76.94	84.01	82.14	9.95	6.04	7.28	8.70	14.00	13.90	232	231	1,264,456
1990	50	118	77.40	84.27	82.18	11.39	4.34	5.30	7.06	15.36	15.17	232	231	1,242,981
1991	49	117	75.63	84.56	82.50	11.76	3.69	4.65	6.39	13.97	13.89	232	231	1,203,887
1992	49	117	76.68	85.77	83.84	10.16	4.08	5.05	6.62	14.81	14.68	231	230	1,231,473
1993	49	117	80.24	85.49	83.43	10.32	4.19	4.96	6.68	14.37	14.29	231	230	1,295,661
1994	49	117	78.50	83.75	81.76	12.84	3.41	4.17	5.90	15.48	15.33	231	230	1,217,242
1995	48	116	78.91	85.82	83.86	10.19	4.00	4.82	6.48	13.87	13.77	232	231	1,207,096
1996	48	114	83.48	87.78	85.76	8.08	4.14	4.73	6.29	13.98	13.90	231	230	1,299,252
1997	49	117	84.97	87.57	85.39	8.52	3.91	4.40	6.25	13.83	13.68	229	228	1,332,493
1998	49	116	84.91	87.33	84.69	8.56	4.11	4.62	6.74	12.82	12.59	230	229	1,374,391
1999	48	115	83.39	86.63	84.05	9.66	3.71	4.25	6.03	13.34	13.18	230	229	1,354,945
2000	48	111	86.86	87.95	85.38	8.40	3.67	4.06	5.45	12.93	12.72	232	230	1,480,626
2001	46	111	84.59	88.99	86.03	7.25	3.76	4.25	5.59	13.21	13.13	231	229	1,398,810
2002	47	113	86.59	88.12	85.71	7.98	3.91	4.32	5.64	14.96	14.78	229	229	1,429,684
2003	45	111	85.75	86.96	83.99	8.55	4.50	4.98	6.47	12.34	12.19	231	229	1,429,927
2004	48	114	86.39	88.84	85.92	7.58	3.58	3.98	5.29	12.15	11.42	231	228	1,437,612
2000-2004:			86.04	88.18	85.41	7.95	3.88	4.32	5.69	13.12	12.85	231	229	1,435,298
1995-2004:			84.56	87.59	85.08	8.48	3.93	4.44	6.02	13.35	13.14	231	229	1,373,449
1982-2004:			80.09	85.60	83.09	10.10	4.29	5.09	6.97	14.38	14.23	231	230	1,288,922

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	20.77	111	59.64	58.90	77.93	76.99	76.34	84.58	80.93	10.60	4.77	5.88	8.95	99.44	375.49
1983	21.73	109	58.02	57.59	78.72	78.12	73.55	82.50	79.28	11.91	5.58	7.05	9.94	99.68	415.64
1984	22.44	110	60.71	60.17	78.41	77.71	77.55	85.24	81.62	10.20	4.56	5.56	8.56	99.80	454.73
1985	23.21	111	60.72	60.31	81.07	80.50	75.14	82.24	79.49	12.72	5.04	6.29	8.59	98.57	435.37
1986	23.43	116	58.93	58.40	78.61	77.91	75.15	83.14	80.62	12.19	4.67	5.86	7.90	99.49	419.29
1987	24.40	117	61.11	60.51	79.75	78.96	76.74	83.20	80.65	12.12	4.68	5.75	7.97	99.28	444.05
1988	25.31	117	62.66	62.33	80.96	80.55	77.59	84.17	81.74	11.09	4.74	5.76	7.78	99.31	471.03
1989	26.26	117	62.74	62.26	81.54	80.91	77.13	84.15	82.27	10.03	5.82	7.02	8.43	99.29	486.09
1990	27.17	118	61.47	61.15	79.40	79.01	77.58	84.28	82.19	11.47	4.25	5.20	6.92	98.76	447.98
1991	28.32	117	59.61	59.21	78.78	78.29	75.66	84.21	82.14	12.09	3.70	4.66	6.39	99.43	477.15
1992	29.31	117	61.56	60.64	80.29	79.08	76.85	85.80	83.88	10.17	4.04	4.99	6.54	99.12	459.82
1993	30.31	117	65.03	64.07	81.05	79.85	80.33	85.32	83.24	10.54	4.14	4.90	6.61	99.44	492.46
1994	31.32	117	60.88	60.06	77.55	76.51	78.56	83.59	81.61	12.94	3.46	4.22	5.92	99.03	448.89
1995	32.35	116	60.26	59.45	76.39	75.33	79.25	85.98	84.08	10.10	3.92	4.72	6.28	99.28	504.15
1996	33.75	114	64.96	63.97	77.80	76.63	83.72	87.76	85.77	8.10	4.14	4.71	6.23	99.43	529.05
1997	34.31	117	67.11	66.36	79.02	78.10	85.25	87.73	85.60	8.33	3.94	4.42	6.20	98.92	545.90
1998	35.24	116	68.65	68.36	80.81	80.51	85.30	87.55	84.95	8.33	4.12	4.60	6.67	98.21	593.51
1999	36.31	113	67.55	67.24	80.98	80.64	83.41	86.56	84.01	9.73	3.71	4.25	5.99	98.80	553.87
2000	36.77	110	73.15	72.70	84.19	83.70	86.99	88.11	85.61	8.26	3.67	4.05	5.39	98.38	600.73
2001	38.17	111	69.88	69.09	82.58	81.68	84.35	88.93	86.07	7.30	3.77	4.28	5.64	99.39	562.75
2002	39.13	113	71.68	71.13	82.77	82.15	86.64	88.15	85.72	7.89	3.96	4.37	5.67	98.80	513.52
2003	40.35	110	71.15	70.61	82.95	82.34	85.75	86.96	84.10	8.55	4.50	4.98	6.44	98.78	616.18
2004	41.46	114	71.66	71.00	82.91	82.18	86.25	88.75	85.90	7.55	3.71	4.12	5.42	93.99	663.43
2000-2004:		558	71.51	70.91	83.09	82.41	86.00	88.18	85.49	7.91	3.92	4.36	5.71	97.94	586.92
1995-2004:		1,134	68.57	67.94	81.07	80.35	84.68	87.64	85.18	8.42	3.94	4.45	5.99	98.43	564.90
1982-2004:		2,627	64.29	63.68	80.25	79.51	80.20	85.60	83.11	10.11	4.30	5.09	6.93	98.96	494.05

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 300-399 MW

Year	Number of Util.	Number of Units	CAPACITY WEIGHTED STATISTICS WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	UNIT STARTS Attempts	UNIT STARTS Actual	Capacity (Net, MW) Max	Capacity (Net, MW) Dep	Net Generation MWHr/U-Yr
1982	42	76	70.48	79.20	72.44	12.81	7.99	10.18	16.89	26.94	26.74	326	323	1,425,640
1983	43	77	71.67	79.09	73.37	13.65	7.26	9.20	14.18	31.76	31.58	327	325	1,453,097
1984	45	82	73.00	80.61	75.92	12.13	7.25	9.04	13.75	28.55	28.24	327	326	1,535,007
1985	47	83	70.63	79.24	74.85	12.54	8.22	10.42	14.94	26.40	26.08	328	327	1,519,944
1986	47	84	67.57	78.78	75.02	14.18	7.05	9.44	13.38	21.09	20.81	329	328	1,379,225
1987	48	84	71.67	79.06	75.54	14.77	6.17	7.92	11.23	21.46	21.21	326	325	1,504,089
1988	48	85	74.32	82.93	78.84	12.67	4.41	5.60	9.83	22.52	22.32	326	325	1,575,455
1989	47	83	72.96	81.55	77.03	12.92	5.53	7.04	11.55	22.93	22.61	327	325	1,560,482
1990	48	86	75.15	82.38	78.23	12.50	5.11	6.37	9.93	21.09	20.87	328	326	1,609,658
1991	49	86	75.84	83.23	79.64	12.50	4.27	5.33	8.87	22.12	21.90	329	327	1,580,190
1992	48	84	74.74	83.34	79.91	12.49	4.17	5.28	8.14	22.23	21.92	329	327	1,606,059
1993	48	85	77.45	83.13	80.13	11.73	5.14	6.22	9.09	21.39	21.09	330	328	1,695,678
1994	48	83	77.51	83.75	80.71	10.18	6.07	7.26	10.22	18.41	17.79	332	331	1,661,537
1995	48	83	75.26	81.96	78.86	12.74	5.30	6.58	9.52	21.32	20.98	332	331	1,594,844
1996	47	82	79.87	84.53	81.77	10.57	4.90	5.78	8.38	21.75	20.87	333	332	1,725,981
1997	48	83	81.55	85.25	82.51	9.25	5.49	6.31	8.58	20.00	19.26	333	332	1,783,081
1998	48	82	83.04	85.86	82.78	8.98	5.16	5.85	8.39	20.11	19.06	334	333	1,853,615
1999	47	81	82.85	84.93	82.16	10.71	4.36	5.00	7.32	20.71	18.67	332	331	1,849,167
2000	44	74	84.20	85.91	83.37	8.81	5.40	6.03	7.95	20.11	19.61	335	333	2,000,754
2001	42	68	85.18	86.36	83.93	9.95	3.68	4.15	5.97	14.13	13.46	338	337	2,030,011
2002	46	76	84.60	85.95	83.23	9.32	4.73	5.30	7.25	17.92	16.73	336	334	2,009,644
2003	44	71	87.07	88.46	86.32	8.19	3.35	3.70	5.16	12.80	12.01	337	336	2,141,815
2004	46	77	86.44	87.39	85.11	8.78	3.83	4.25	6.00	12.61	11.83	336	335	2,119,882
2000-2004:			85.50	86.81	84.39	9.00	4.21	4.69	6.48	15.54	14.75	336	335	2,060,632
1995-2004:			82.87	85.60	82.93	9.76	4.65	5.31	7.48	18.31	17.40	334	333	1,902,118
1982-2004:			77.41	83.13	79.60	11.44	5.43	6.56	9.74	21.32	20.77	331	329	1,697,182

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	13.95	76	50.86	49.95	72.08	70.88	69.67	78.93	72.20	12.91	8.16	10.49	17.30	99.26	228.27
1983	14.80	77	51.26	50.70	71.40	70.74	70.88	78.81	73.21	13.76	7.43	9.49	14.46	99.43	196.63
1984	15.53	80	53.95	53.42	73.79	73.17	72.09	80.17	75.45	12.44	7.38	9.29	14.13	98.91	224.25
1985	16.22	81	53.30	52.84	75.37	74.81	69.79	78.94	74.56	12.67	8.39	10.73	15.34	98.79	234.46
1986	16.82	84	48.25	47.85	71.35	70.82	66.73	78.32	74.57	14.41	7.28	9.83	13.84	98.67	280.77
1987	17.81	83	53.01	52.60	73.93	73.39	70.86	78.47	74.97	15.19	6.33	8.21	11.59	98.84	292.67
1988	18.77	85	55.37	54.96	74.46	73.95	73.51	82.41	78.22	13.08	4.51	5.78	10.22	99.11	289.30
1989	19.57	83	55.05	54.51	75.38	74.71	72.32	81.16	76.59	13.13	5.71	7.32	11.98	98.60	280.18
1990	20.47	83	56.47	55.98	75.00	74.49	74.53	82.07	77.83	12.62	5.30	6.64	10.38	98.96	312.82
1991	21.23	84	55.49	54.87	73.09	72.35	75.08	82.85	79.22	12.76	4.39	5.52	9.19	99.01	300.31
1992	22.02	83	56.34	55.61	75.24	74.40	74.00	83.05	79.54	12.68	4.28	5.46	8.41	98.61	296.56
1993	23.05	82	59.36	58.73	76.56	75.84	76.79	82.80	79.85	11.92	5.28	6.43	9.28	98.60	318.95
1994	24.14	82	57.83	57.19	74.49	73.79	76.91	83.46	80.43	10.35	6.19	7.45	10.41	96.63	378.74
1995	25.19	82	55.53	54.84	73.71	72.87	74.79	81.81	78.70	12.71	5.48	6.83	9.81	98.41	312.24
1996	26.19	82	59.59	58.99	74.56	73.87	79.33	84.34	81.57	10.63	5.03	5.96	8.59	95.95	333.92
1997	27.25	83	61.88	61.21	75.82	75.05	81.10	85.10	82.33	9.40	5.50	6.35	8.67	96.30	368.86
1998	28.16	82	63.93	63.28	76.92	76.21	82.69	85.73	82.57	9.12	5.15	5.86	8.50	94.78	380.03
1999	29.13	81	63.96	63.67	77.40	76.85	82.16	84.54	81.65	10.96	4.51	5.20	7.66	90.15	384.62
2000	29.61	73	68.94	68.00	81.81	80.76	83.79	85.62	83.04	8.90	5.59	6.26	8.21	97.51	375.30
2001	30.50	68	69.63	68.55	81.73	80.48	85.03	86.24	83.82	10.00	3.75	4.22	6.03	95.26	553.40
2002	31.44	76	69.30	68.34	81.82	80.78	84.13	85.60	82.82	9.48	4.92	5.53	7.56	93.36	440.56
2003	32.13	71	73.34	72.47	84.22	83.23	86.77	88.18	86.00	8.38	3.44	3.82	5.31	93.83	632.88
2004	33.94	77	72.69	71.90	84.09	83.18	86.31	87.31	84.96	8.87	3.83	4.24	6.08	93.81	640.86
2000-2004:		365	70.79	69.87	82.76	81.72	85.20	86.59	84.12	9.12	4.32	4.82	6.65	94.92	506.59
1995-2004:		774	65.62	64.88	79.16	78.29	82.45	85.38	82.66	9.88	4.75	5.45	7.67	95.03	415.35
1982-2004:		1,836	59.18	58.54	76.39	75.63	76.74	82.79	79.23	11.64	5.57	6.77	10.04	97.42	323.87

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 400-599 MW

	Number of		CAPACITY WEIGHTED STATISTICS							UNIT STARTS		Capacity (Net, MW)		Net Generation
Year	Util.	Units	WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	Attempts	Actual	Max	Dep	MWHr/U-Yr
1982	55	138	72.95	78.93	73.47	13.86	7.21	8.99	14.16	21.75	21.45	496	492	2,319,084
1983	57	142	75.02	80.67	75.59	12.59	6.73	8.24	12.59	20.74	20.55	498	494	2,424,746
1984	58	146	74.50	79.75	75.50	13.19	7.07	8.66	12.15	18.62	18.35	498	494	2,492,962
1985	58	147	76.30	81.92	78.24	13.03	5.47	6.69	9.63	20.15	19.05	498	493	2,503,573
1986	58	148	73.57	80.56	77.24	13.65	5.78	7.29	10.23	21.54	21.32	499	495	2,335,986
1987	59	149	76.55	82.05	78.80	12.60	5.35	6.53	9.35	19.41	19.16	499	496	2,577,306
1988	59	151	77.39	81.74	78.29	13.59	4.67	5.70	8.91	18.34	18.19	497	494	2,648,632
1989	59	150	77.51	82.19	79.21	12.63	5.17	6.26	8.81	19.16	18.86	497	494	2,663,925
1990	60	154	77.93	82.22	78.86	12.51	5.29	6.35	9.21	19.38	19.05	499	496	2,641,136
1991	60	155	77.83	81.91	78.71	12.77	5.32	6.39	9.04	17.26	17.05	500	497	2,648,203
1992	60	156	77.50	81.63	78.53	13.88	4.49	5.48	7.95	20.35	19.88	504	501	2,656,363
1993	60	156	78.54	82.85	79.10	12.36	4.79	5.75	8.98	24.47	24.06	505	501	2,728,141
1994	61	155	78.53	83.37	79.59	12.51	4.14	5.00	8.00	22.66	22.03	506	503	2,714,086
1995	61	157	79.25	83.88	81.00	11.23	4.88	5.80	8.17	25.95	25.39	506	503	2,761,597
1996	62	162	81.33	84.70	81.39	10.53	4.77	5.54	8.08	27.27	26.29	505	502	2,870,187
1997	63	163	82.95	85.04	81.83	9.84	5.12	5.81	8.36	19.16	18.51	506	503	2,952,643
1998	64	163	84.27	85.68	82.30	9.80	4.52	5.09	8.04	15.96	15.33	507	505	3,055,789
1999	63	161	84.26	85.09	82.16	10.09	4.82	5.41	7.70	15.14	14.23	508	505	3,100,899
2000	62	161	86.95	87.38	84.51	8.84	3.78	4.17	6.30	13.62	13.06	509	507	3,344,281
2001	58	140	84.10	85.30	82.96	9.73	4.97	5.58	7.37	13.99	13.63	510	507	3,209,305
2002	60	153	85.31	86.20	83.30	8.88	4.92	5.45	7.79	20.83	19.89	510	508	3,249,402
2003	58	137	86.02	86.93	84.22	8.38	4.73	5.21	7.40	12.87	12.29	511	509	3,327,038
2004	61	146	86.39	87.20	84.88	8.65	4.17	4.61	6.49	13.61	12.96	512	511	3,365,369
2000-2004:			85.78	86.62	83.98	8.89	4.50	4.98	7.05	15.05	14.43	510	508	3,299,917
1995-2004:			84.05	85.72	82.82	9.62	4.66	5.26	7.57	17.96	17.28	508	506	3,117,336
1982-2004:			79.90	83.43	80.07	11.49	5.11	6.01	8.78	19.26	18.75	504	500	2,812,651

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	8.42	135	53.93	53.37	73.91	73.16	72.72	78.84	73.41	13.99	7.17	8.97	14.15	98.62	297.03
1983	9.06	141	56.08	55.56	74.76	74.07	75.02	80.79	75.77	12.59	6.62	8.11	12.44	99.08	319.81
1984	9.90	144	57.42	56.99	77.09	76.50	74.46	79.95	75.80	13.23	6.82	8.39	11.87	98.55	356.21
1985	10.49	146	57.83	57.37	75.80	75.19	76.24	82.10	78.43	12.96	5.31	6.52	9.51	94.54	350.60
1986	11.38	148	53.98	53.45	73.39	72.65	73.39	80.59	77.30	13.79	5.62	7.11	10.06	98.98	301.40
1987	12.32	148	59.50	58.96	77.77	77.02	76.28	81.97	78.78	12.72	5.31	6.51	9.30	98.71	348.76
1988	13.22	150	61.19	60.65	79.08	78.37	77.34	81.80	78.37	13.56	4.64	5.66	8.88	99.18	373.28
1989	14.19	150	61.63	61.14	79.54	78.88	77.54	82.27	79.27	12.62	5.10	6.18	8.78	98.43	360.15
1990	15.07	153	61.02	60.47	78.32	77.59	77.85	82.30	78.91	12.50	5.22	6.28	9.19	98.30	358.01
1991	15.96	154	61.07	60.44	78.47	77.66	77.64	81.89	78.69	12.77	5.34	6.44	9.10	98.78	398.87
1992	16.91	155	60.60	59.97	78.22	77.39	77.09	81.40	78.32	14.08	4.53	5.55	8.03	97.69	340.64
1993	17.85	155	62.34	61.73	79.36	78.59	78.19	82.66	78.98	12.57	4.77	5.75	8.92	98.32	284.66
1994	18.67	153	61.81	61.28	78.73	78.03	78.24	83.28	79.61	12.59	4.14	5.02	7.96	97.22	311.11
1995	19.46	155	62.85	62.36	79.31	78.68	79.10	83.93	81.05	11.13	4.94	5.88	8.27	97.84	272.91
1996	20.02	161	65.32	64.67	80.26	79.52	81.34	84.83	81.51	10.43	4.74	5.51	8.08	96.41	271.65
1997	20.93	163	67.18	66.66	80.91	80.36	82.82	84.95	81.72	9.90	5.15	5.86	8.43	96.61	391.97
1998	21.79	163	69.30	68.83	82.23	81.67	84.24	85.72	82.31	9.80	4.48	5.05	8.05	96.05	481.37
1999	22.83	161	70.21	69.75	83.32	82.78	84.09	84.96	81.97	10.12	4.91	5.52	7.86	93.99	517.52
2000	23.67	161	75.42	74.79	86.73	86.01	86.84	87.29	84.36	8.90	3.82	4.21	6.40	95.89	584.10
2001	24.28	140	72.58	71.87	86.30	85.46	83.90	85.15	82.77	9.76	5.09	5.72	7.56	97.43	539.27
2002	25.53	153	73.30	72.72	85.91	85.25	85.11	86.10	83.12	8.96	4.93	5.48	7.91	95.49	374.86
2003	26.45	137	75.04	74.30	87.24	86.38	85.91	86.93	84.17	8.35	4.76	5.25	7.49	95.49	612.38
2004	27.56	145	75.07	74.83	86.83	86.62	86.35	87.25	84.89	8.65	4.14	4.57	6.48	95.22	585.27
2000-2004:		736	74.30	73.72	86.60	85.94	85.66	86.56	83.87	8.92	4.53	5.02	7.15	95.88	520.60
1995-2004:		1,538	70.52	69.97	83.87	83.25	83.93	85.69	82.75	9.62	4.69	5.30	7.66	96.21	425.81
1982-2004:		3,469	64.27	63.72	80.44	79.76	79.72	83.39	80.04	11.54	5.09	6.00	8.80	97.35	372.69

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 600-799 MW

Year	Number of Util.	Number of Units	CAPACITY WEIGHTED STATISTICS WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	UNIT STARTS Attempts	Actual	Capacity (Net, MW) Max	Dep	Net Generation MWHr/U-Yr
1982	32	68	76.44	79.76	74.12	13.03	7.20	8.61	13.65	17.86	17.80	677	674	3,533,564
1983	34	70	77.16	80.07	75.26	13.48	6.45	7.71	12.29	19.91	19.63	679	676	3,568,793
1984	37	75	77.92	79.77	76.23	11.80	8.43	9.76	13.19	19.15	18.66	678	676	3,651,945
1985	38	79	76.52	78.69	75.61	14.13	7.29	8.69	11.78	17.14	16.73	677	675	3,606,127
1986	39	82	78.15	80.83	76.91	12.47	6.70	7.90	11.67	26.05	25.55	677	674	3,621,883
1987	39	83	79.65	82.07	79.30	11.70	6.23	7.25	9.97	15.69	15.27	679	678	3,887,162
1988	40	88	80.18	81.81	78.89	11.85	6.33	7.32	10.09	15.54	14.91	675	674	3,964,549
1989	41	87	81.98	83.51	80.85	11.27	5.23	5.99	8.41	20.79	20.47	674	673	3,975,338
1990	41	87	82.87	84.64	82.29	11.43	3.93	4.53	6.58	13.04	12.56	675	674	3,966,848
1991	40	88	82.58	84.99	82.45	10.94	4.07	4.70	6.95	12.30	11.95	676	675	3,919,522
1992	41	89	82.91	85.60	83.31	10.94	3.46	4.01	6.01	11.68	11.30	680	680	3,978,323
1993	40	88	82.77	84.93	82.35	10.52	4.55	5.21	7.51	11.41	11.22	680	679	3,995,653
1994	41	89	84.15	85.31	82.45	11.04	3.65	4.15	6.66	12.86	12.42	681	680	4,035,448
1995	40	89	86.75	88.14	85.78	8.30	3.56	3.94	6.09	11.13	10.69	681	680	4,148,442
1996	39	88	86.21	87.25	84.62	8.78	3.97	4.40	6.49	11.56	11.14	683	681	4,148,420
1997	39	88	87.19	87.58	85.11	7.82	4.60	5.01	7.13	12.09	11.66	683	682	4,277,622
1998	39	88	87.42	87.74	84.75	7.21	5.05	5.46	7.97	12.01	11.72	684	683	4,378,541
1999	39	88	86.05	86.40	83.70	9.19	4.42	4.88	7.09	12.49	11.95	685	684	4,325,215
2000	39	87	85.60	85.88	83.29	9.66	4.46	4.96	7.16	12.73	12.56	690	689	4,527,860
2001	37	85	84.96	85.66	83.16	9.50	4.84	5.39	7.20	12.76	12.20	692	689	4,455,290
2002	37	85	86.46	86.86	84.13	8.70	4.44	4.88	6.91	15.71	15.04	693	691	4,522,521
2003	37	85	88.04	88.40	85.78	7.82	3.80	4.13	6.09	11.20	10.47	694	692	4,697,036
2004	39	91	85.85	86.10	83.62	9.46	4.44	4.91	6.78	11.42	10.62	692	689	4,571,689
2000-2004:			86.18	86.58	83.99	9.03	4.40	4.85	6.82	12.74	12.15	692	690	4,555,144
1995-2004:			86.45	87.00	84.39	8.65	4.36	4.80	6.89	12.29	11.79	688	686	4,403,615
1982-2004:			83.20	84.64	81.74	10.37	5.00	5.67	8.19	14.44	14.00	682	681	4,094,761

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	8.45	65	60.00	59.68	78.48	78.08	76.26	79.67	74.04	13.05	7.28	8.71	13.69	99.66	374.81
1983	9.16	68	60.41	60.10	78.30	77.89	77.00	80.06	75.22	13.43	6.51	7.79	12.40	98.59	343.30
1984	9.58	72	61.75	61.39	79.27	78.79	77.74	79.69	76.18	11.72	8.59	9.95	13.35	97.44	365.71
1985	10.13	76	61.18	60.81	79.92	79.48	76.58	78.87	75.78	14.16	7.08	8.46	11.57	97.61	401.06
1986	10.64	80	61.66	61.12	78.91	78.21	78.03	80.76	76.89	12.59	6.65	7.85	11.56	98.08	267.35
1987	11.18	82	65.75	65.33	82.54	82.01	79.79	82.19	79.40	11.69	6.12	7.12	9.87	97.32	457.75
1988	12.17	85	67.20	66.88	83.82	83.41	80.03	81.68	78.74	11.89	6.43	7.43	10.26	95.95	471.06
1989	13.05	86	67.65	67.30	82.49	82.10	82.01	83.56	80.90	11.22	5.22	5.99	8.43	98.46	350.99
1990	14.00	86	67.48	67.07	81.43	80.93	83.03	84.82	82.49	11.32	3.86	4.44	6.50	96.32	579.11
1991	14.71	88	66.52	66.17	80.54	80.12	82.67	85.11	82.61	10.87	4.02	4.64	6.89	97.15	605.99
1992	15.66	88	67.09	66.57	80.92	80.30	82.73	85.49	83.28	11.08	3.44	3.99	5.95	96.75	643.09
1993	16.64	88	67.54	67.06	81.61	81.02	82.86	85.04	82.55	10.44	4.52	5.17	7.40	98.33	646.93
1994	17.69	88	68.10	67.61	80.93	80.34	84.19	85.40	82.57	10.95	3.65	4.16	6.65	96.58	593.84
1995	18.69	89	70.08	69.52	80.77	80.14	86.71	88.08	85.75	8.36	3.57	3.95	6.07	96.05	710.56
1996	19.81	88	69.76	69.12	80.94	80.17	86.36	87.41	84.84	8.66	3.93	4.35	6.41	96.37	680.98
1997	20.81	88	71.98	71.50	82.57	82.01	87.20	87.61	85.15	7.88	4.51	4.92	7.03	96.44	655.17
1998	21.79	88	73.48	73.11	84.06	83.64	87.41	87.75	84.81	7.24	5.01	5.42	7.89	97.59	653.32
1999	22.81	88	72.57	72.07	84.32	83.76	85.98	86.36	83.71	9.26	4.38	4.85	7.02	95.68	630.30
2000	23.59	84	75.11	74.70	87.75	87.27	85.57	85.84	83.28	9.67	4.49	4.99	7.17	98.66	598.44
2001	24.44	85	74.02	73.52	87.12	86.53	84.98	85.70	83.20	9.47	4.83	5.37	7.16	95.61	610.18
2002	25.44	85	74.85	74.47	86.57	86.14	86.38	86.80	84.06	8.74	4.47	4.91	6.91	95.74	503.13
2003	26.44	85	77.71	77.27	88.27	87.77	87.98	88.32	85.74	7.88	3.81	4.15	6.05	93.48	736.07
2004	26.73	91	75.73	75.23	88.20	87.63	85.82	86.07	83.62	9.51	4.42	4.90	6.71	92.99	709.84
2000-2004:		430	75.49	75.04	87.59	87.08	86.14	86.54	83.97	9.06	4.40	4.86	6.79	95.37	621.76
1995-2004:		870	73.53	73.04	85.05	84.49	86.44	87.00	84.42	8.67	4.34	4.78	6.84	95.93	642.79
1982-2004:		1,923	68.93	68.48	82.84	82.31	83.17	84.64	81.76	10.38	4.99	5.66	8.16	96.95	520.68

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 800-999 MW

Year	Number of Util.	Number of Units	CAPACITY WEIGHTED STATISTICS WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	UNIT STARTS Attempts	UNIT STARTS Actual	Capacity (Net, MW) Max	Capacity (Net, MW) Dep	Net Generation MWHr/U-Yr
1982	8	19	74.65	77.31	71.40	12.12	10.57	12.40	18.54	19.17	19.01	817	817	4,120,912
1983	8	20	76.22	77.40	73.45	13.60	8.99	10.56	14.63	17.10	16.20	823	823	4,269,385
1984	8	22	77.82	80.76	77.33	13.21	6.03	7.19	10.76	16.44	16.06	821	821	4,355,445
1985	7	20	78.51	83.81	81.91	10.90	5.30	6.32	8.38	14.90	14.55	832	832	4,657,831
1986	7	20	79.58	84.45	81.75	9.90	5.69	6.67	9.68	13.65	13.50	834	834	4,720,593
1987	7	21	76.26	84.57	82.53	11.18	4.26	5.29	7.63	12.57	12.43	831	831	4,402,611
1988	8	23	77.51	87.24	85.72	9.44	3.32	4.11	5.93	12.23	11.77	831	831	4,546,702
1989	9	25	73.61	87.01	85.13	10.12	2.87	3.75	6.04	12.69	11.68	832	832	4,348,482
1990	9	25	79.59	88.92	87.46	7.49	3.52	4.23	5.65	11.39	10.86	832	831	4,597,747
1991	9	25	78.01	88.06	86.25	8.07	3.87	4.73	6.44	12.28	11.60	833	832	4,482,734
1992	9	25	77.43	87.60	86.64	9.48	2.92	3.64	4.60	12.76	11.04	830	830	4,576,241
1993	9	25	79.29	83.45	82.15	11.09	5.46	6.45	7.74	10.56	10.28	831	831	4,715,029
1994	9	25	85.06	87.41	85.29	8.65	3.95	4.43	6.30	11.72	11.36	832	830	5,019,253
1995	9	25	83.38	85.25	83.43	10.27	4.48	5.10	6.80	10.52	9.76	832	831	4,975,811
1996	9	25	86.83	87.34	85.59	8.80	3.85	4.25	5.53	10.88	10.64	834	832	5,256,481
1997	9	25	87.82	88.31	86.80	8.70	2.99	3.29	4.56	10.35	10.03	834	834	5,365,953
1998	9	25	87.47	88.07	86.64	8.40	3.53	3.88	5.14	10.23	10.23	837	837	5,453,184
1999	9	25	86.47	86.64	85.10	10.19	3.18	3.55	4.86	11.88	11.84	839	839	5,457,816
2000	9	25	86.93	87.17	85.90	10.13	2.70	3.01	3.86	12.00	12.00	838	838	5,644,038
2001	8	20	85.52	86.25	84.03	11.20	2.55	2.90	4.13	10.65	10.65	835	835	5,268,303
2002	9	25	85.98	86.01	84.27	10.45	3.56	3.98	5.61	14.16	14.12	840	839	5,601,152
2003	9	25	86.81	86.87	85.72	10.49	2.64	2.95	4.01	9.08	9.04	840	840	5,753,094
2004	9	25	89.30	90.34	89.52	7.07	2.60	2.82	3.40	8.00	7.48	842	842	5,986,926
2000-2004:			86.97	87.38	85.97	9.81	2.82	3.14	4.20	10.78	10.66	839	839	5,666,636
1995-2004:			86.68	87.25	85.74	9.54	3.22	3.58	4.80	10.78	10.58	837	837	5,480,578
1982-2004:			82.01	85.91	83.98	9.93	4.16	4.83	6.66	12.23	11.83	833	832	4,966,065

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	7.59	19	57.90	57.54	77.59	77.08	74.73	77.42	71.17	12.00	10.58	12.40	18.85	99.17	344.43
1983	8.10	20	59.23	59.26	77.80	77.74	76.05	77.24	73.11	13.67	9.09	10.67	14.94	94.74	411.21
1984	8.60	21	60.38	60.40	77.62	77.61	77.77	80.72	77.09	13.16	6.12	7.29	11.06	97.69	425.36
1985	9.05	20	63.96	63.93	81.53	81.42	78.29	83.84	81.94	10.86	5.30	6.34	8.41	97.65	471.35
1986	10.05	20	64.64	64.60	81.27	81.18	79.40	84.35	81.49	9.86	5.83	6.84	10.04	98.90	515.24
1987	10.52	21	60.58	60.50	79.46	79.34	76.13	84.53	82.35	11.22	4.25	5.29	7.81	98.89	536.55
1988	11.06	22	62.40	62.29	80.53	80.37	77.42	87.12	85.53	9.50	3.38	4.18	6.10	96.24	577.91
1989	10.94	25	59.79	59.68	81.26	81.07	73.47	86.87	84.94	10.25	2.88	3.78	6.14	92.04	551.07
1990	11.91	25	63.20	63.09	79.45	79.28	79.53	88.77	87.32	7.61	3.55	4.28	5.69	95.35	641.51
1991	12.82	25	61.56	61.46	78.94	78.79	77.99	87.93	86.14	8.03	4.04	4.92	6.61	94.46	588.89
1992	13.80	25	62.86	62.74	81.25	81.03	77.08	87.53	86.57	9.55	2.91	3.64	4.61	86.52	613.28
1993	14.80	25	64.93	64.78	81.91	81.70	79.37	83.53	82.21	11.05	5.43	6.40	7.71	97.35	676.33
1994	15.80	25	69.10	68.90	81.24	81.00	85.02	87.36	85.16	8.65	3.99	4.48	6.44	96.93	655.62
1995	16.80	25	68.50	68.30	82.21	81.92	83.13	84.96	83.09	10.36	4.68	5.33	7.08	92.78	746.11
1996	17.80	25	72.06	71.76	82.97	82.64	86.82	87.33	85.52	8.77	3.90	4.30	5.65	97.79	716.75
1997	18.79	25	73.57	73.43	83.79	83.61	87.82	88.30	86.68	8.66	3.03	3.34	4.72	96.91	767.03
1998	19.79	25	74.51	74.39	85.19	85.04	87.35	87.95	86.42	8.49	3.56	3.91	5.27	100.00	747.89
1999	20.80	25	74.32	74.26	85.93	85.87	86.51	86.67	85.07	10.04	3.29	3.66	5.04	99.66	640.02
2000	21.80	25	77.65	76.65	89.37	88.18	86.96	87.21	85.87	10.05	2.74	3.06	3.96	100.00	636.54
2001	21.25	20	73.79	72.03	86.29	84.22	85.37	86.10	83.70	11.29	2.61	2.96	4.34	100.00	702.20
2002	23.80	25	76.81	76.16	89.32	88.58	85.99	86.01	84.23	10.42	3.58	4.00	5.68	99.72	533.47
2003	24.80	25	78.89	78.20	90.87	90.07	86.65	86.71	85.54	10.59	2.70	3.02	4.10	99.56	839.64
2004	25.80	25	81.26	80.94	90.97	90.64	89.28	90.28	89.43	7.08	2.64	2.87	3.47	93.50	1048.44
2000-2004:		120	77.85	77.00	89.52	88.54	86.91	87.31	85.84	9.83	2.86	3.19	4.30	98.89	715.03
1995-2004:		245	75.18	74.68	86.74	86.16	86.61	87.17	85.59	9.54	3.29	3.66	4.94	98.14	717.72
1982-2004:		537	68.30	68.02	83.30	82.94	81.90	85.82	83.81	9.95	4.22	4.90	6.83	96.73	606.95

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

1982-2004 Historical Availability Statistics

FOSSIL Coal Primary 1000 MW Plus

Year	Number of Util.	Units	WSF	WAF	WEAF	WSOF	WFOF	WFOR	WEFOR	Unit Starts Attempts	Unit Starts Actual	Capacity (Net, MW) Max	Capacity (Net, MW) Dep	Net Generation MWHr/U-Yr
1982	4	9	66.01	73.65	67.86	17.75	8.59	11.51	16.35	10.56	10.56	1,232	1,232	5,209,417
1983	4	9	73.18	82.46	79.08	11.05	6.48	8.13	11.63	10.44	10.44	1,225	1,225	5,939,575
1984	4	9	71.04	74.55	72.72	14.68	10.76	13.16	15.07	14.89	11.33	1,223	1,223	5,446,674
1985	5	10	75.60	77.40	75.02	14.03	8.57	10.18	12.29	12.10	11.40	1,231	1,231	6,230,221
1986	5	10	83.61	85.04	82.96	9.23	5.73	6.41	8.57	13.70	12.80	1,231	1,231	7,034,879
1987	5	10	73.85	75.20	72.85	14.86	9.93	11.86	14.20	13.20	12.40	1,235	1,235	5,903,240
1988	5	10	81.33	83.45	80.22	11.22	5.33	6.15	9.23	10.30	9.70	1,235	1,235	6,518,229
1989	5	11	80.10	80.51	75.36	13.48	6.02	6.99	11.64	11.01	10.61	1,235	1,235	6,485,553
1990	5	11	79.98	80.25	76.27	11.85	7.90	8.99	11.45	11.82	11.36	1,241	1,241	6,550,240
1991	6	12	81.42	82.38	78.74	13.33	4.29	5.00	6.68	11.92	11.50	1,188	1,188	6,527,214
1992	6	12	80.92	83.11	80.48	12.84	4.05	4.77	5.58	8.67	8.17	1,253	1,253	7,316,149
1993	6	12	82.04	83.69	81.05	12.66	3.65	4.26	5.27	10.67	10.50	1,253	1,253	7,323,227
1994	6	12	78.66	79.26	76.91	13.72	7.03	8.20	8.92	10.00	9.67	1,253	1,253	6,025,860
1995	6	12	79.97	80.31	77.66	14.11	5.58	6.53	7.61	10.75	10.17	1,253	1,253	6,273,525
1996	6	12	84.84	85.23	83.04	11.36	3.41	3.86	4.85	10.42	9.42	1,253	1,253	6,664,072
1997	6	12	87.40	88.27	86.16	6.18	5.55	5.97	7.12	9.17	8.75	1,238	1,238	6,937,703
1998	6	12	83.79	83.83	81.02	10.78	5.39	6.04	7.44	9.83	9.42	1,234	1,234	6,625,176
1999	6	12	83.32	83.38	80.08	10.77	5.85	6.56	8.27	11.33	10.83	1,238	1,234	6,555,239
2000	6	12	82.61	82.66	80.35	10.60	6.74	7.54	9.01	11.75	11.58	1,239	1,235	7,648,486
2001	6	12	83.42	84.24	82.16	9.38	6.38	7.10	8.48	11.17	11.17	1,238	1,234	7,714,140
2002	6	12	86.19	86.41	84.22	6.50	7.09	7.60	9.16	10.65	10.48	1,239	1,235	8,196,671
2003	6	12	78.46	78.56	76.58	12.02	9.43	10.73	11.95	10.08	9.75	1,238	1,234	7,608,617
2004	6	12	83.41	83.51	81.49	9.69	6.80	7.54	8.77	12.92	12.08	1,240	1,236	8,196,566
2000-2004:			82.81	83.07	80.95	9.65	7.29	8.09	9.46	11.31	11.01	1,239	1,235	7,871,994
1995-2004:			83.33	83.64	81.27	10.15	6.22	6.94	8.26	10.81	10.36	1,241	1,239	7,240,692
1982-2004:			80.45	81.85	79.06	11.71	6.44	7.41	9.23	11.12	10.57	1,237	1,236	6,789,948

TRADITIONAL NON-WEIGHTED STATISTICS

Year	AGE	U-Yrs	GCF	NCF	GOF	NOF	SF	AF	EAF	SOF	FOF	FOR	EFOR	SR	ART
1982	8.11	9	48.29	48.28	73.10	73.13	66.40	73.64	67.74	17.63	8.72	11.61	16.69	100.00	550.80
1983	9.11	9	55.50	55.35	75.75	75.64	72.81	81.64	78.14	11.73	6.62	8.33	11.99	100.00	610.90
1984	10.11	9	50.80	50.72	71.59	71.39	69.74	73.37	71.46	14.94	11.67	14.34	16.37	76.09	540.69
1985	10.10	10	57.74	57.75	76.40	76.40	75.15	76.87	74.48	14.49	8.64	10.32	12.48	94.21	577.48
1986	11.10	10	65.28	65.23	78.04	78.01	83.61	85.07	82.89	9.15	5.78	6.47	8.75	93.43	572.23
1987	12.10	10	54.62	54.57	73.93	73.90	73.05	74.48	72.10	15.44	10.08	12.13	14.55	93.94	516.06
1988	13.10	10	60.22	60.10	74.04	73.89	81.34	83.63	80.32	10.99	5.37	6.20	9.38	94.17	736.62
1989	13.98	10	60.09	59.92	75.00	74.81	79.90	80.33	75.07	13.62	6.05	7.04	11.89	96.37	659.75
1990	13.82	11	60.45	60.27	75.55	75.35	79.48	79.76	75.77	12.27	7.97	9.12	11.68	96.11	612.92
1991	13.58	12	62.91	62.73	77.23	77.05	82.04	82.98	79.47	12.65	4.37	5.06	6.74	96.48	624.93
1992	14.58	12	67.18	66.45	82.98	82.12	80.77	82.95	80.34	12.88	4.17	4.91	5.75	94.23	868.39
1993	15.58	12	67.41	66.70	82.19	81.30	82.17	83.77	81.14	12.51	3.72	4.33	5.37	98.41	685.51
1994	16.58	12	55.56	54.89	70.47	69.78	78.48	79.08	76.77	13.98	6.94	8.13	8.86	96.70	710.94
1995	17.58	12	58.00	57.14	72.61	71.45	79.88	80.23	77.57	14.03	5.74	6.71	7.86	94.60	688.05
1996	18.58	12	61.39	60.53	72.25	71.35	84.62	85.01	82.82	11.52	3.48	3.94	4.96	90.40	789.05
1997	19.58	12	64.74	63.95	74.17	73.17	87.58	88.42	86.32	5.99	5.60	6.01	7.15	95.42	876.85
1998	20.58	12	61.32	61.27	73.16	73.12	83.81	83.85	81.07	10.72	5.43	6.09	7.49	95.83	779.42
1999	21.58	12	60.54	60.42	72.67	72.52	83.27	83.34	79.97	10.75	5.92	6.63	8.42	95.59	673.55
2000	22.58	12	70.26	70.27	84.96	85.06	82.03	82.09	79.67	10.93	6.98	7.84	9.41	98.55	622.27
2001	23.58	12	71.08	71.11	85.18	85.25	83.27	84.11	81.91	9.34	6.55	7.29	8.76	100.00	653.03
2002	24.51	12	75.47	75.57	87.54	87.67	86.09	86.30	84.02	6.67	7.03	7.55	9.19	98.40	719.44
2003	25.58	12	70.16	70.13	89.42	89.39	77.75	77.85	75.74	12.46	9.68	11.07	12.41	96.73	698.56
2004	26.58	12	75.35	75.26	90.32	90.23	83.06	83.17	81.05	9.82	7.02	7.79	9.12	93.50	603.96
2000-2004:		60	72.45	72.46	87.46	87.50	82.43	82.69	80.47	9.85	7.45	8.29	9.76	97.35	656.54
1995-2004:		120	66.83	66.54	80.20	79.85	83.13	83.43	81.01	10.23	6.34	7.09	8.47	95.84	703.50
1982-2004:		256	62.89	62.60	78.14	77.81	80.24	81.62	78.79	11.81	6.57	7.57	9.46	95.05	665.50

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support of
Direct Testimony

July 18, 2006

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM
DISTRIBUTION OF KEY PARAMETERS
Date-10/13/05

FOSSIL Oil Primary All MW Sizes 2000-2004 Data

EAF	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
0.0- 0.9	1	0.69	1	0.69
28.0- 28.9	1	0.69	2	1.38
36.0- 36.9	1	0.69	3	2.07
44.0- 44.9	1	0.69	4	2.76
47.0- 47.9	1	0.69	5	3.45
51.0- 51.9	1	0.69	6	4.14
55.0- 55.9	1	0.69	7	4.83
58.0- 58.9	1	0.69	8	5.52
62.0- 62.9	2	1.38	10	6.90
63.0- 63.9	1	0.69	11	7.59
64.0- 64.9	1	0.69	12	8.28
65.0- 65.9	1	0.69	13	8.97
66.0- 66.9	2	1.38	15	10.34
68.0- 68.9	3	2.07	18	12.41
70.0- 70.9	1	0.69	19	13.10
71.0- 71.9	1	0.69	20	13.79
72.0- 72.9	1	0.69	21	14.48
73.0- 73.9	3	2.07	24	16.55
74.0- 74.9	2	1.38	26	17.93
75.0- 75.9	2	1.38	28	19.31
76.0- 76.9	7	4.83	35	24.14
77.0- 77.9	2	1.38	37	25.52
78.0- 78.9	4	2.76	41	28.28
79.0- 79.9	4	2.76	45	31.03
80.0- 80.9	6	4.14	51	35.17
81.0- 81.9	3	2.07	54	37.24
82.0- 82.9	3	2.07	57	39.31
83.0- 83.9	2	1.38	59	40.69
84.0- 84.9	4	2.76	63	43.45
85.0- 85.9	4	2.76	67	46.21
86.0- 86.9	10	6.90	77	53.10
87.0- 87.9	6	4.14	83	57.24
88.0- 88.9	10	6.90	93	64.14
89.0- 89.9	10	6.90	103	71.03
90.0- 90.9	7	4.83	110	75.86
91.0- 91.9	6	4.14	116	80.00
92.0- 92.9	10	6.90	126	86.90
93.0- 93.9	4	2.76	130	89.66
94.0- 94.9	3	2.07	133	91.72
95.0- 95.9	1	0.69	134	92.41
96.0- 96.9	4	2.76	138	95.17
98.0- 98.9	2	1.38	140	96.55
99.0- 99.9	2	1.38	142	97.93
100%	3	2.07	145	100.00

NCF	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
-1.0- -0.1	4	2.76	4	2.76
0.0- 0.9	13	8.97	17	11.72
1.0- 1.9	3	2.07	20	13.79
2.0- 2.9	4	2.76	24	16.55
3.0- 3.9	1	0.69	25	17.24
4.0- 4.9	12	8.28	37	25.52
5.0- 5.9	4	2.76	41	28.28
6.0- 6.9	3	2.07	44	30.34
7.0- 7.9	6	4.14	50	34.48
8.0- 8.9	3	2.07	53	36.55
9.0- 9.9	3	2.07	56	38.62
10.0- 10.9	5	3.45	61	42.07
11.0- 11.9	1	0.69	62	42.76
12.0- 12.9	2	1.38	64	44.14
13.0- 13.9	3	2.07	67	46.21
14.0- 14.9	2	1.38	69	47.59
15.0- 15.9	5	3.45	74	51.03
16.0- 16.9	2	1.38	76	52.41
17.0- 17.9	3	2.07	79	54.48
18.0- 18.9	1	0.69	80	55.17
19.0- 19.9	2	1.38	82	56.55
20.0- 20.9	1	0.69	83	57.24
21.0- 21.9	1	0.69	84	57.93
24.0- 24.9	1	0.69	85	58.62
25.0- 25.9	2	1.38	87	60.00
26.0- 26.9	1	0.69	88	60.69
27.0- 27.9	1	0.69	89	61.38
28.0- 28.9	1	0.69	90	62.07
29.0- 29.9	1	0.69	91	62.76
30.0- 30.9	1	0.69	92	63.45
31.0- 31.9	1	0.69	93	64.14
33.0- 33.9	1	0.69	94	64.83
34.0- 34.9	3	2.07	97	66.90
35.0- 35.9	2	1.38	99	68.28
36.0- 36.9	2	1.38	101	69.66
37.0- 37.9	1	0.69	102	70.34
38.0- 38.9	2	1.38	104	71.72
39.0- 39.9	1	0.69	105	72.41
42.0- 42.9	3	2.07	108	74.48
44.0- 44.9	1	0.69	109	75.17
45.0- 45.9	2	1.38	111	76.55
47.0- 47.9	3	2.07	114	78.62
48.0- 48.9	2	1.38	116	80.00
49.0- 49.9	2	1.38	118	81.38
50.0- 50.9	1	0.69	119	82.07
51.0- 51.9	2	1.38	121	83.45
52.0- 52.9	4	2.76	125	86.21
53.0- 53.9	1	0.69	126	86.90
54.0- 54.9	2	1.38	128	88.28
55.0- 55.9	1	0.69	129	88.97
56.0- 56.9	5	3.45	134	92.41
57.0- 57.9	1	0.69	135	93.10
58.0- 58.9	1	0.69	136	93.79
59.0- 59.9	1	0.69	137	94.48
60.0- 60.9	1	0.69	138	95.17
63.0- 63.9	2	1.38	140	96.55
65.0- 65.9	1	0.69	141	97.24
70.0- 70.9	1	0.69	142	97.93
74.0- 74.9	1	0.69	143	98.62
75.0- 75.9	2	1.38	145	100.00

FOR	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
0.0- 0.9	66	45.52	66	45.52
1.0- 1.9	30	20.69	96	66.21
2.0- 2.9	10	6.90	106	73.10
3.0- 3.9	13	8.97	119	82.07
4.0- 4.9	7	4.83	126	86.90
5.0- 5.9	6	4.14	132	91.03
6.0- 6.9	5	3.45	137	94.48
7.0- 7.9	1	0.69	138	95.17
8.0- 8.9	1	0.69	139	95.86
9.0- 9.9	2	1.38	141	97.24
11.0- 11.9	2	1.38	143	98.62
12.0- 12.9	1	0.69	144	99.31
14.0- 14.9	1	0.69	145	100.00

EFOR	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
0.0- 0.9	24	16.55	24	16.55
1.0- 1.9	10	6.90	34	23.45
2.0- 2.9	7	4.83	41	28.28
3.0- 3.9	10	6.90	51	35.17
4.0- 4.9	7	4.83	58	40.00
5.0- 5.9	10	6.90	68	46.90
6.0- 6.9	8	5.52	76	52.41
7.0- 7.9	8	5.52	84	57.93
8.0- 8.9	4	2.76	88	60.69
9.0- 9.9	4	2.76	92	63.45
10.0- 10.9	4	2.76	96	66.21
11.0- 11.9	3	2.07	99	68.28
12.0- 12.9	4	2.76	103	71.03
13.0- 13.9	1	0.69	104	71.72
14.0- 14.9	1	0.69	105	72.41
15.0- 15.9	2	1.38	107	73.79
16.0- 16.9	3	2.07	110	75.86
17.0- 17.9	1	0.69	111	76.55
18.0- 18.9	1	0.69	112	77.24
19.0- 19.9	2	1.38	114	78.62
20.0- 20.9	2	1.38	116	80.00
21.0- 21.9	1	0.69	117	80.69
22.0- 22.9	1	0.69	118	81.38
23.0- 23.9	2	1.38	120	82.76
24.0- 24.9	3	2.07	123	84.83
26.0- 26.9	1	0.69	124	85.52
34.0- 34.9	3	2.07	127	87.59
35.0- 35.9	1	0.69	128	88.28
36.0- 36.9	1	0.69	129	88.97
38.0- 38.9	1	0.69	130	89.66
40.0- 40.9	1	0.69	131	90.34
44.0- 44.9	1	0.69	132	91.03
47.0- 47.9	1	0.69	133	91.72
57.0- 57.9	2	1.38	135	93.10
59.0- 59.9	1	0.69	136	93.79
61.0- 61.9	1	0.69	137	94.48
62.0- 62.9	1	0.69	138	95.17
69.0- 69.9	1	0.69	139	95.86
71.0- 71.9	1	0.69	140	96.55
76.0- 76.9	1	0.69	141	97.24
78.0- 78.9	1	0.69	142	97.93
85.0- 85.9	1	0.69	143	98.62
97.0- 97.9	1	0.69	144	99.31
100%	1	0.69	145	100.00

EFORd	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
0.0- 0.9	43	29.66	43	29.66
1.0- 1.9	14	9.66	57	39.31
2.0- 2.9	20	13.79	77	53.10
3.0- 3.9	11	7.59	88	60.69
4.0- 4.9	12	8.28	100	68.97
5.0- 5.9	6	4.14	106	73.10
6.0- 6.9	6	4.14	112	77.24
7.0- 7.9	10	6.90	122	84.14
8.0- 8.9	5	3.45	127	87.59
9.0- 9.9	4	2.76	131	90.34
10.0- 10.9	2	1.38	133	91.72
11.0- 11.9	3	2.07	136	93.79
12.0- 12.9	2	1.38	138	95.17
15.0- 15.9	2	1.38	140	96.55
18.0- 18.9	1	0.69	141	97.24
19.0- 19.9	1	0.69	142	97.93
20.0- 20.9	1	0.69	143	98.62
29.0- 29.9	1	0.69	144	99.31
100%	1	0.69	145	100.00

YEAR	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
1941	1	0.69	1	0.69
1947	2	1.38	3	2.07
1948	5	3.45	8	5.52
1949	4	2.76	12	8.28
1950	2	1.38	14	9.66
1951	3	2.07	17	11.72
1952	6	4.14	23	15.86
1953	7	4.83	30	20.69
1954	5	3.45	35	24.14
1955	5	3.45	40	27.59
1956	3	2.07	43	29.66
1957	1	0.69	44	30.34
1958	7	4.83	51	35.17
1959	4	2.76	55	37.93
1960	4	2.76	59	40.69
1961	5	3.45	64	44.14
1962	4	2.76	68	46.90
1963	6	4.14	74	51.03
1964	4	2.76	78	53.79
1965	3	2.07	81	55.86
1966	2	1.38	83	57.24
1967	2	1.38	85	58.62
1968	6	4.14	91	62.76
1969	2	1.38	93	64.14
1970	1	0.69	94	64.83
1971	2	1.38	96	66.21
1972	6	4.14	102	70.34
1973	3	2.07	105	72.41
1974	12	8.28	117	80.69
1975	5	3.45	122	84.14
1976	4	2.76	126	86.90
1977	9	6.21	135	93.10
1978	2	1.38	137	94.48
1979	1	0.69	138	95.17
1980	5	3.45	143	98.62
1981	2	1.38	145	100.00

RATING (MW)	FREQUENCY	PERCENT	CUMULATIVE FREQUENCY	CUMULATIVE PERCENT
0.0- 19.9 MW	3	2.07	3	2.07
20.0- 39.9 MW	6	4.14	9	6.21
40.0- 59.9 MW	16	11.03	25	17.24
60.0- 79.9 MW	14	9.66	39	26.90
80.0- 99.9 MW	6	4.14	45	31.03
100.0-119.9 MW	10	6.90	55	37.93
120.0-139.9 MW	9	6.21	64	44.14
140.0-159.9 MW	3	2.07	67	46.21
160.0-179.9 MW	8	5.52	75	51.72
180.0-199.9 MW	4	2.76	79	54.48
200.0-219.9 MW	2	1.38	81	55.86
220.0-239.9 MW	4	2.76	85	58.62
260.0-279.9 MW	1	0.69	86	59.31
280.0-299.9 MW	2	1.38	88	60.69
300.0-319.9 MW	5	3.45	93	64.14
360.0-379.9 MW	8	5.52	101	69.66
380.0-399.9 MW	3	2.07	104	71.72
400.0-419.9 MW	10	6.90	114	78.62
420.0-439.9 MW	4	2.76	118	81.38
500.0-519.9 MW	4	2.76	122	84.14
540.0-559.9 MW	2	1.38	124	85.52
560.0-579.9 MW	2	1.38	126	86.90
600.0-619.9 MW	5	3.45	131	90.34
620.0-639.9 MW	1	0.69	132	91.03
700.0-719.9 MW	1	0.69	133	91.72
740.0-759.9 MW	1	0.69	134	92.41
780.0-799.9 MW	2	1.38	136	93.79
820.0-839.9 MW	1	0.69	137	94.48
840.0-859.9 MW	4	2.76	141	97.24
860.0-879.9 MW	3	2.07	144	99.31
1000+ MW	1	0.69	145	100.00

CASE: UE 180/UE 181
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Direct Testimony

July 18, 2006

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 200 IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 06-111. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 180 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

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

A. My name is Bill Wordley. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301. I am a Senior Economist in the Economic Research & Financial Analysis Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. My witness qualification statement is found in Staff/201, Wordley/1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In this testimony I will describe two of staff's proposed adjustments to the power costs that PGE has included in its filed case. I will also describe limitations with the company's power cost modeling, and staff's recommendation that the company pursue stochastic power cost modeling for use in rate making.

Q. PLEASE SUMMARIZE THE TWO ADJUSTMENTS TO POWER COSTS.

A. Staff proposes the following adjustments to PGE's power costs:

(1) A reduction of $1,647,885 to match the costs and revenues from ancillary services that PGE provides to other entities; and

(2) A reduction of $12,352,530 to account for the extrinsic value associated with PGE's flexible purchase power contracts and gas-fired generating plants.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING PGE'S POWER COST MODELING?

A. The Commission should indicate a preference for stochastic power cost modeling. Modeling the uncertainty and interaction associated with system loads, electricity and natural gas market prices, hydroelectric generation, and thermal unit availability provides a more realistic simulation of PGE's system operations, the company's expected power costs, and produces a distribution of power costs that can be used to design a fair power cost adjustment mechanism.

Adjustment for Ancillary Services

Q. WHAT ARE ANCILLARY SERVICES?

A. The North American Electric Reliability Council (NERC) defines ancillary services as:

> *Those services that are necessary to support the transmission of capacity and energy from the resources to the loads while maintaining reliable operation of the provider's transmission system in accordance with good utility practice. (Source: NERC website)*

Q. HOW LONG HAS PGE BEEN SELLING ANCILLARY SERVICES?

A. The company's response to staff discovery indicates PGE began selling ancillary services in June 2005.

Q. WHY IS STAFF PROPOSING AN ADJUSTMENT IN THIS CASE FOR ANCILLARY SERVICES?

A. Exhibit 202 is a copy of the company's response to staff DR 307. In that response the company said:

> *In the 2007 test year revenue requirement, we do include the costs of ancillary service sales, but not the corresponding revenues.*

Staff's proposed adjustment corrects the mismatch of benefits and costs.

Q. HOW WAS STAFF'S ADJUSTMENT CALCULATED?

A. The company provided data in its response to staff DR 307 that indicated revenue from ancillary services sales was [redacted] (confidential) for the eleven month period June 2005-April 2006. Staff annualized this value to develop the proposed [redacted] (confidential) adjustment.

Power Cost Modeling

Q. WHERE ARE THE LIMITATIONS IN PGE'S POWER COST MODELING?

A. The company should be commended for committing resources and expertise to the development and improvement of its MONET power cost modeling capability. The concerns that staff has are not with the MONET model logic and structure but rather with the some of the primary inputs to the model.

Q. WHICH INPUTS TO MONET CONCERN STAFF?

A. The major variable inputs to MONET that concern staff are retail system loads, market prices for electricity and natural gas, thermal power plant forced outages, and hydro generation availability. These are the primary driving variables to power costs in MONET.

Q. WHAT CONCERNS DOES STAFF HAVE WITH THESE VARIABLE INPUTS TO MONET?

A. The major inputs to MONET are normalized/smoothed, deterministic and assumed to be not correlated. In reality, these variables are not smooth, volatile, uncertain, and correlated to some extent. Unfortunately, the unrealistic representation of the major inputs in MONET yields a power cost estimate that is inconsistent with the expected actual operation of PGE's system. Consequently, MONET's power cost estimate should not be included in rates without adjustment. The extrinsic value adjustment proposed by staff will improve the company's MONET power cost estimate.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE PROBLEM WITH THE MONET INPUTS THAT YOU HAVE IDENTIFIED?

A. Yes. For example, the hourly system load used in MONET assumes "normal" weather (15-year average), which yields a smooth load shape. This is not how loads (or weather) occur on an actual basis. The difference between the smooth loads in MONET and bumpy actual loads contribute to a significant difference in the actual operation of the power system compared to what is modeled in MONET.

Power plant forced outages in MONET are assumed to be spread evenly over all hours of the test year. In actual operation plant forced outages are random. PGE simply "derates" or reduces the capacity available from all power plants in all hours. This means that, even during profitable market conditions, MONET prevents the maximum generation output from occurring in the modeling run, unrealistically limiting profit margins and resulting in an increase to "modeled" power cost.

Much like the smoothed representation of system load, the power and natural gas price inputs to MONET are also smoothed. Again, this is not how market prices occur on an actual basis. The smoothed representation of prices prevents MONET from capturing profitable market opportunities that occur in actual operation. Exhibit 203 is a comparison of the shape of actual Mid-Columbia power prices, on and off-peak, and actual Sumas gas prices for May 2006 to the representation of these prices in MONET. These graphs illustrate the difference between actual and normalized prices. This difference contributes to a significant difference in the actual operation of the power system to what is modeled in MONET.

Another limitation related to the primary inputs variables in MONET is that there is no correlation assumed between the variables. Correlation is a measure of the extent to which two variables change together. It is likely that some level of correlation exists, for example, between loads and power prices, between hydro conditions and power prices, and between gas price and power price. By not capturing these correlations between variables, MONET is not accurately portraying the real world of power operations.

Q. WHAT DOES STAFF RECOMMEND REGARDING THE PROBLEMS YOU HAVE IDENTIFIED RELATED TO THE INPUTS TO MONET?

A. Staff recommends that the company actively pursue stochastic power cost modeling. Stochastic modeling can provide a more realistic simulation of PGE's actual power system operations. It can provide a realistic representation of the variability, and any interactions, associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability. In addition, stochastic power cost modeling provides a distribution of power costs that can be used to design a reasonable PCA mechanism. This modeling will improve "normalization" of power costs and assessment of power cost risk.

Q. HAS STAFF RECOMMENDED STOCHASTIC POWER COST MODELING BEFORE?

A. Yes. In docket UE 165, staff testimony recommended stochastic power cost modeling for PGE. In dockets UE 173 and UE 179, staff testimony recommended stochastic power cost modeling for PacifiCorp.

Q. WHAT COMMITMENT DID PGE MAKE IN UE 165 REGARDING STOCHASTIC POWER COST MODELING?

A. As part of a stipulation between staff and the company in UE 165, PGE committed to work with staff to evaluate stochastic modeling of power costs for possible incorporation into rates.

Q. WHAT IS THE STATUS OF THAT EVALUATION EFFORT?

A. The company hired a consultant who conducted an initial study on the potential and issues surrounding stochastic power cost modeling. There is still more work to do before a determination can be made regarding the use of stochastically modeled power cost in rates. Staff supports the company's efforts, and would like to see more progress on the company's part soon. However, at this point, it is not clear to staff that PGE will make any additional effort to develop stochastic power cost modeling capability without the Commission indicating its desire for the company to continue that development.

Q. ARE THERE INSTANCES WHERE PGE HAS USED STOCHASTIC MODELING IN PROCEEDINGS BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON?

A. Yes. In the company's last Integrated Resource Plan (IRP docket LC-33), PGE used stochastic modeling to help identify the best resource plan. (See Delivering New Choices for PGE's Customers, August 2002; Chapter 3, page 17 and Appendix M. Use of Stochastic Electric Prices in Our Plan)

In addition, PGE used its "spread-option" model to evaluate resource alternative bids received in response to the company's 2004 request-for-proposals (RFP) for resource capacity. The RFP was conducted following Commission acknowledgement of the company's resource action plan in LC-33. The spread-option model includes and considers the volatility and correlation between natural gas and power market prices in determining the value of resources.

Q. IS IT APPROPRIATE TO TRANSFER THESE STOCHASTIC MODELING TECHNIQUES FROM THE RESOURCE PLANNING AND ACQUISITION ARENA TO THE RATEMAKING ARENA?

A. Yes. The elements that PGE has modeled stochastically for purposes of resource planning and evaluating resource alternatives are some of the same elements that have traditionally been, and currently are, normalized in the determination of test year revenue requirements. Risk is an important consideration in both resource planning and ratemaking. In each arena, sound decision-making requires the best possible measurement and assessment of the relevant risks. In the IRP arena, the company and Commission evaluate the risks associated with alternative portfolios comprised of existing resources and resource additions. The goal is to select the least-cost and least-risk resource portfolio. In the ratemaking arena, the company and Commission need to consider the risks of the existing resource portfolio and evaluate alternative forms of regulation. The goal is to select ratemaking methods that allocate risk fairly and provide the company with the opportunity to earn the allowed rate-of-return. Staff recommends that the Commission employ a consistent approach when considering portfolio risk. It is inconsistent to use sophisticated risk modeling when making IRP decisions, only to revert to deterministic or point-estimate modeling when making ratemaking decisions.

Q. IS STAFF'S PROPOSED EXTRINSIC VALUE ADJUSTMENT RELATED TO THE LIMITATIONS OF THE EXISTING MONET POWER COST MODELING YOU HAVE DISCUSSED EARLIER IN YOUR TESTIMONY?

A. Yes. If the company successfully implemented stochastic power cost modeling, there would no longer be a need for staff's proposed extrinsic value adjustment. Stochastic power cost modeling would mitigate the concerns regarding the primary inputs to MONET discussed earlier, and would capture the option (extrinsic) value of the of PGE's flexible resources.

Q. IS THIS CASE THE FIRST TIME STAFF HAS PROPOSED THE EXTRINSIC VALUE ADJUSTMENT?

A. No. While this is the first PGE case in which staff has presented written testimony recommending an extrinsic value adjustment, it is not the first time staff proposed this adjustment. (Staff also recently offered testimony recommending an extrinsic value adjustment in PacifiCorp's current general rate case, UE 179). Further, staff has proposed the extrinsic value adjustment in settlement negotiations in the last three PacifiCorp general rate cases (UE 147, UE 170, and UE 179).

Extrinsic Value Adjustment

Q. WHAT IS EXTRINSIC VALUE OF POWER RESOURCES?

A. Extrinsic value is the dollar value produced by the flexibility of a power resource to operate profitably in a wholesale power market characterized by volatile and correlated natural gas and electricity prices. This flexibility is also called optionality. It is widely understood in the industry that optionality has value. In the following passage from PGE's last IRP the company acknowledges the concept of extrinsic value:

> *The optionality of physical plants, particularly the ability to shut them off when market prices are low, allows them to push down overall costs when market prices are volatile, although not on average higher than under conditions of stable prices.*

(Delivering New Choices for PGE' Customers, August 2002; page 192)

While acknowledging the existence of optionality or extrinsic value in its IRP, the company has not incorporated it into ratemaking.

Q. WHAT DO YOU MEAN BY FLEXIBILITY OF A POWER RESOURCE?

A. Flexibility of power plant is the ability to run or not run the plant. Flexible purchase power contracts contain specific provisions that allow the buyer to decide when to take delivery of power from the seller (e.g. call options).

Q. HOW IS THIS FLEXIBILITY USED?

A. During actual operation of the power system, PGE has the option, depending on market conditions, to use or not use its flexible resources to make a positive margin. The company runs its power plants and takes delivery from its flexible purchase power contracts whenever the market price for power exceeds the cost of producing power from its plants or exceeds the cost of contract power. The company does not run its power plants or take delivery from its flexible purchase power contracts whenever the market price for power is less than the cost of producing power from its plants or less than the cost of contract power. This is called economic dispatch.

Q. HOW IS THE EXTRINSIC VALUE CREATED?

A. Extrinsic value comes from the profitable opportunities that result from application of economic dispatch of the company's flexible resources in the uncertain market. As discussed earlier in this testimony, this inherent uncertainty in market prices is not included in MONET; consequently PGE's power cost forecast needs to be adjusted for the extrinsic value of the company's flexible resources not captured by MONET.

Q. WHICH OF PGE'S POWER RESOURCES HAVE EXTRINSIC VALUE IN THE TEST YEAR?

A. Generally, for a resource to have extrinsic value in any forecasted period, the resource will not be dispatched or used to its full capacity, that is, the resource has unused capacity. In the 2007 test year in this case, two of the PGE's power plants and three purchase power contracts have unused capacity.

Q. HOW MUCH UNUSED POWER RESOURCE CAPACITY IS THERE IN THE COMPANY'S FILLED CASE?

A. All of the PGE's existing gas-fired generating plants have a lot of unused capacity in the company's filed case. The Beaver plant has 85% unused capacity in MONET. This is all of Beaver's available capacity; the other 15% is the forced outage derate. Coyote Springs has 39% unused capacity in MONET (out of 88% total available capacity; with the other 12% being the forced outage derate). The three purchase power contracts with unused capacity in MONET are the PPM cold snap contract at 100% unused, the PPM super-peak contract also with 100% unused and the Morgan Stanley tolling contract with 12% unused.

Q. HOW DID STAFF ESTIMATE EXTRINSIC VALUE?

A. Staff based its calculation of the extrinsic value on PGE's estimates of extrinsic value developed for the evaluation of alternative bids in response to the company's 2004 RFP for resource capacity. Staff took the estimates of extrinsic value from the RFP bid evaluation and used these as the basis to develop extrinsic value estimates for each of the resources with unused capacity in the company's filled case that were identified above. Two of the three contracts in the test year with unused capacity were evaluated in the RFP. Staff used those extrinsic value estimates directly. For the third contract with unused capacity, staff based its estimate on the heat rate in the contract compared to the heat rates in the other two contracts. The extrinsic value for the Beaver and Coyote Springs plants was based on the average extrinsic value (in $/MWh) from the two 2004 RFP bids that actually resulted in contracts, plus each plant's specific MW capacity, heat rate (MMBtu/MWh), and unused capacity as estimated by MONET. Finally staff included an estimated extrinsic value for the 43 MW of dispatchable standby generation at customer's facilities on PGE's system. Staff's estimate of extrinsic value is $13,990,685. (See Exhibit 204, Alternative I)

Q. WHY DID STAFF BASE THIS ITS ESTIMATE ON THE FULL DERATED AVAILABLE CAPACITY OF THE GAS PLANTS?

A. Staff used the available resource capacity values that PGE used in its filling. An alternative for the Commission to consider would be based on historical capacity utilization. In 2001 Beaver ran at 67% of capacity and Coyote Springs at 87% (source: FERC Form 1). Using these historical capacity utilization values as a cap yields an estimate of $12,352,530 for extrinsic value (Alternative II in Exhibit 204).

Yet another alternative would be using a 10-year average (Coyote Springs came online in 1995) of capacity utilization, which is 24% for Beaver and 61% for Coyote Springs (source: FERC Form 1). Using these average capacity utilization values yields an estimate of $5,758,597 for extrinsic value (Alternative III in Exhibit 204).

Q. WHAT IS STAFF'S RECOMMENDED ADJUSTMENT FOR EXTRINSIC VALUE?

A. Staff recommends alternative II, a reduction of $12,352,530. The alternative II approach acknowledges the extrinsic value in the unused (by MONET) resource capacity, while limiting that capacity utilization to what has been used in the past. This limitation recognizes operating considerations such as minimum generation unit up and down times, generating unit ramp rates (e.g. from zero to maximum generation, and from maximum to zero generation), and gas delivery constraints.

Q. WHY DID STAFF USE THE COMPANY'S ESTIMATES OF EXTRINSIC VALUE FROM AN EARLIER DOCKET?

A. Staff used the most recent and only PGE-specific data available to it in calculating the adjustment. Staff asked the company in Staff DR 306 to provide estimates of extrinsic value based on the MONET model run that supported the company's filing in this docket, but the company response was that 'We have not performed the extensive studies requested". So staff used the only estimate of extrinsic value it has, which was one developed and used by PGE to help evaluate RFP bids. Extrinsic value is an important benefit that always needs to be included in the total value determination of any power resource alternative.

Q. IS STAFF'S EXTRINSIC VALUE ADJUSTMENT CONSISTENT WITH NORMALIZED RATEMAKING?

Yes. This adjustment improves normalized rate-making by recognizing characteristics of company assets that provide value not captured by "traditional" normalized rate-making for power costs. The company, but not customers, has been benefiting from the extrinsic value of the resource capacity not dispatched by MONET. Customers are paying the full cost of the company's resources, and are entitled to all benefits derived from those investments. Staff's recommended adjustment remedies this mismatch between costs and benefits.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 180/UE 181
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

July 18, 2006

WITNESS QUALIFICATION STATEMENT

NAME: Bill Wordley

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Economic Research & Financial Analysis Division

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: All course work towards Masters in Economics
Portland State University

B.S. Portland State University
Major: Mathematics

EXPERIENCE: Since August 2000 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research and providing technical support on a wide range of cost, revenue and policy issues for gas, electric and telephone utilities. Active participation in all primary energy rate cases in Oregon during past six years, including providing testimony in UM 995, UE 116, UE 134, UE 170, and UE 173.

From March 1999 to August 2000 I worked as a consultant in the energy field working for electric utilities and utility organizations. Work included load forecasting and operations planning.

From 1972 to 1999 I worked for PacifiCorp in various analytical and management positions dealing with long and short-term load, sales, and revenue forecasting, power operations planning, power contract optimization, merger and acquisition support, strategic planning support, market research, retail market planning, load-resource analysis, and power contract administration. I testified in some 30 regulatory proceedings in Oregon, Washington, Idaho, Montana, Wyoming, and California.

CASE: UE 180/UE 181
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 202

Exhibits in Support of Direct Testimony

July 18, 2006

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 202 IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 06-111. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 180 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

May 17, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 20, 2006
Question No. 307

Request:

Please provide, in electronic format, detail for 2005 (actual data) and 2007 (test period projection) that identifies all revenue from auxiliary services provided by the company to other parties. For all revenue components, please identify counter-party and specific auxiliary service provided, for example, contingency reserves. Where are these revenues included in the Company's filing in this docket?

Response:

Attachment 307-A is an Excel workbook which includes actual data from June 2005, when we first began selling ancillary services, through April 2006. All sales listed in Attachment 307-A were to the California Independent System Operator (ISO). The services provided were day-ahead and hour-ahead spinning reserves. Attachment 307-A is proprietary and confidential, and subject to the protective order in this docket (Order No. 06-111).

Attachment 307-A shows that rates, as well as revenues, vary widely from month to month. It is also very difficult to project 2007 on the basis of only 11 months of experience. Finally, MONET does not include an estimate of these ancillary service sales, but it also does not include an estimate of the effect of making these sales on our hydro dispatch. In practice, sales of ancillary services often competes with optimal economic dispatch of our hydro resources, moving dispatch into non-peak hours.

In the 2007 test year revenue requirement, we do include the costs of ancillary service sales, but not the corresponding revenues. However, given the considerations discussed in the preceding paragraph, there is considerable risk around making a revenue projection for the test year.

Adoption of the Annual Variance Tariff proposed in PGE Exhibit 400 would ease concern about including an ancillary services revenue estimate in the test year revenue requirement.

Attachment 307-A is Confidential and Subject to Protective Order No. 06-111. It is provided under separate cover.

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This page is confidential.

You must have signed the protective order in this docket in order to view this page.

CASE: UE 180/UE 181
WITNESS: Bill Wordley

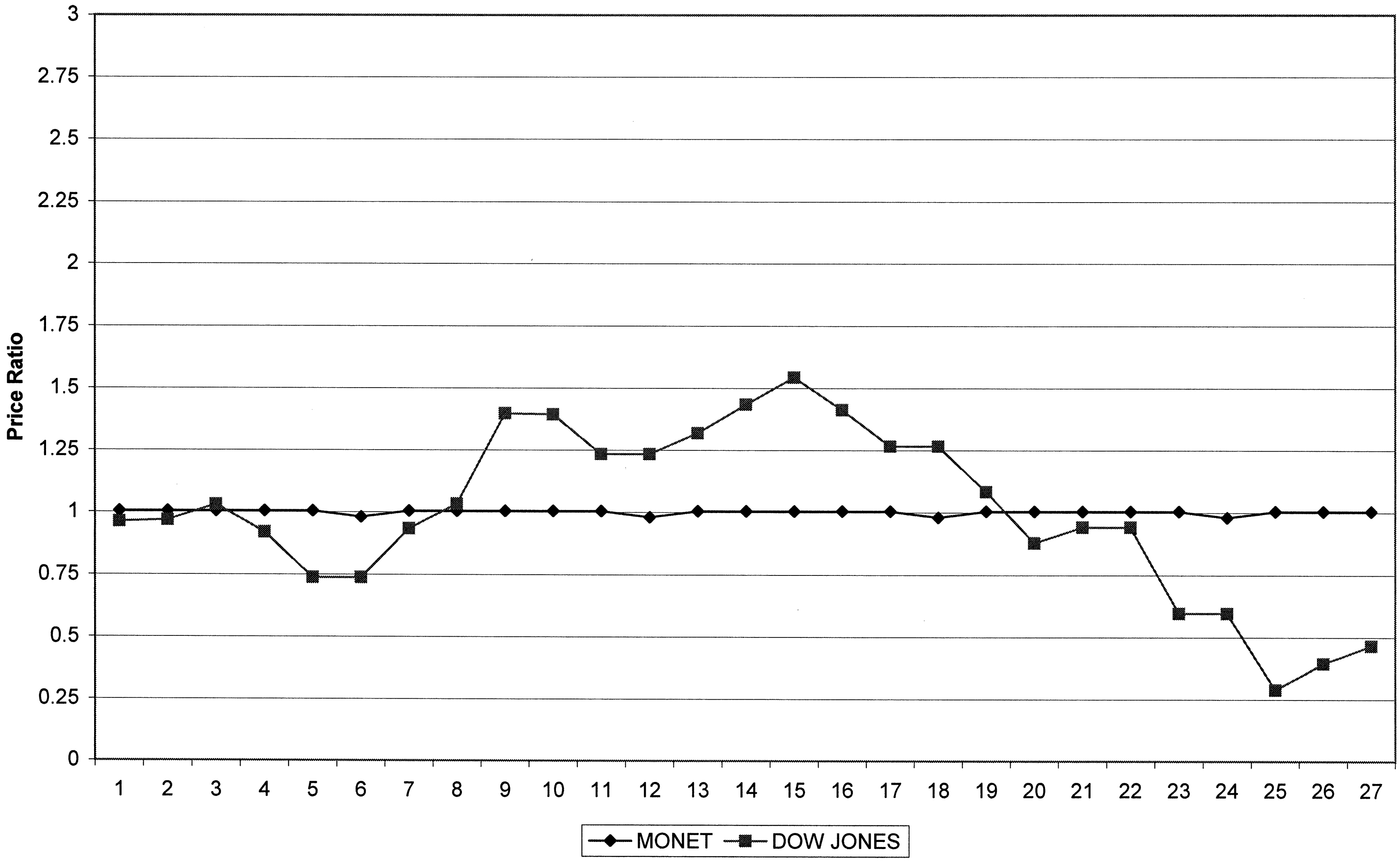
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support of
Direct Testimony

July 18, 2006

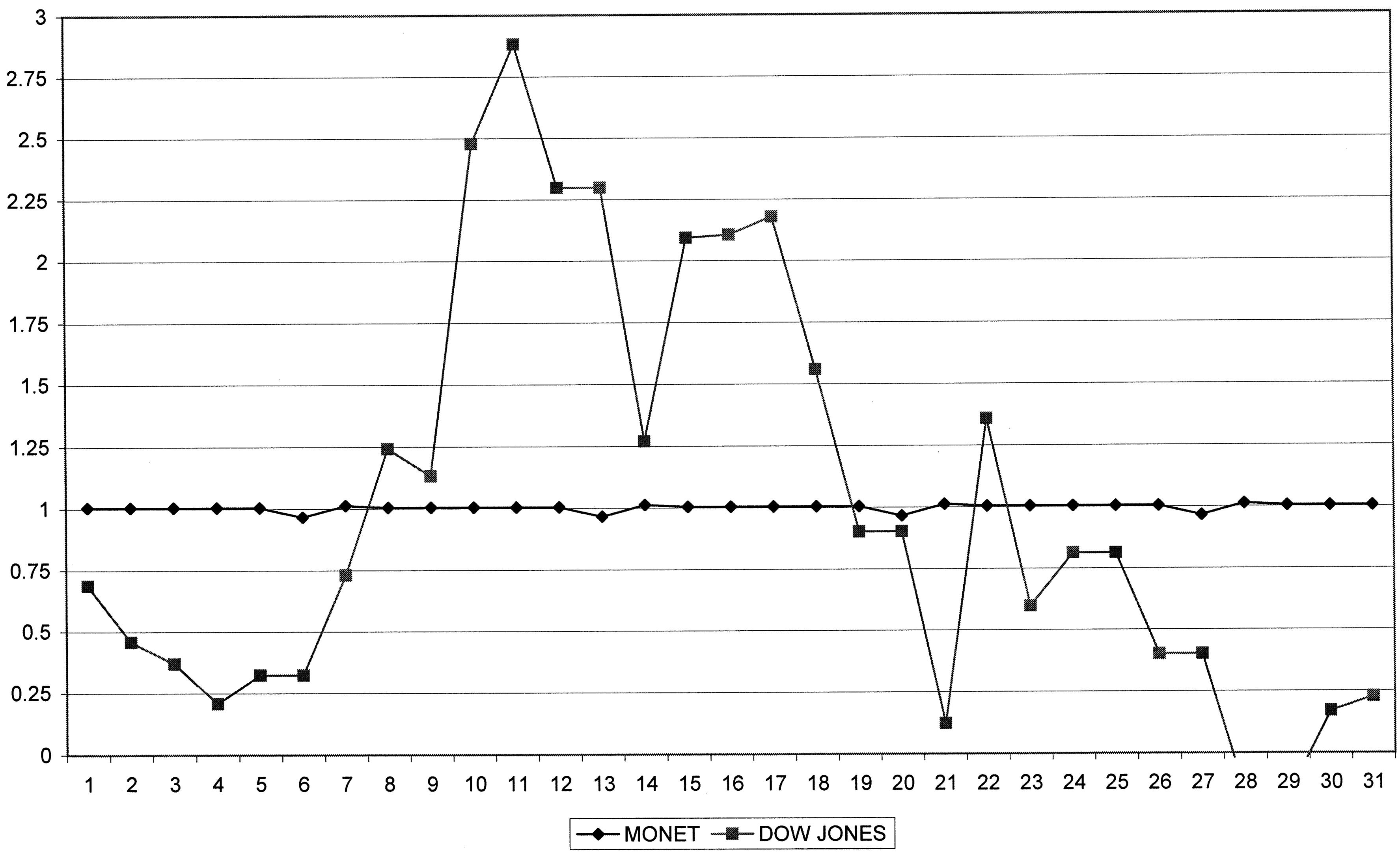
May On-Peak Electricity Price Shape (MONET v. 2006 Dow Jones Index)



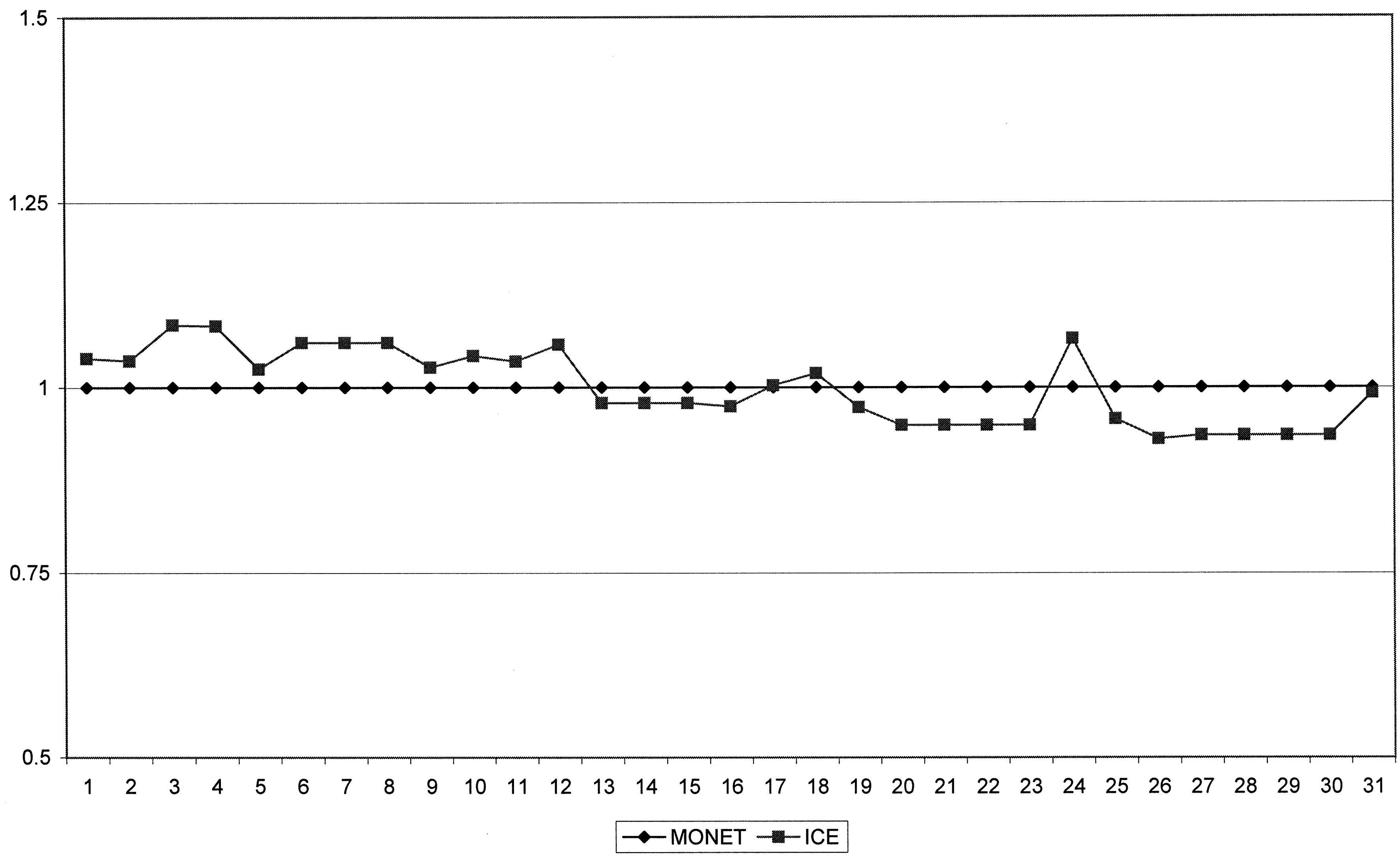
Note: May 2006 had 27 on-peak price days.

Staff/203
Wordley/1

May Off-Peak Electricity Price Shape (MONET v. 2006 Dow Jones Index)



May Natural Gas Price Shape (MONET v. 2006 ICE Index)



Staff/203
Wordley/3

CASE: UE 180/UE 181
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support of
Direct Testimony

July 18, 2006

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 204

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 06 111. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 180 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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UE 180/UE 181
Extrinsic Value of Thermal Plants
Staff Calculation

		Capacity* MW	Heat Rate* MMBtu/MWh	CF%	Filled UE 180 Potential CF%	Unused CF%	Unused MWh	$/MWh**	Extrinsic Value
Alternative I									
	Beaver	562	10.0258	0.0	79.2	79.2	3,899,111	2	$ 7,798,222
	Coyote Springs	256	7.5788	41.8	92.8	51.0	1,143,776	4	$ 4,575,103
Alternative II									
	Beaver	562	10.0258	0.0	67.3	67.3	3,313,260	2	$ 6,626,520
	Coyote Springs	256	7.5788	41.8	87.6	45.8	1,027,163	4	$ 4,108,650
Alternative III									
	Beaver	562	10.0258	0.0	24.2	24.2	1,191,395	2	$ 2,382,790
	Coyote Springs	256	7.5788	41.8	61.4	19.6	439,612	4	$ 1,758,447

* 2005 PGE FERC Form 1
** based on contracts average of $3/MWh (see Staff/204, Wordley/1);
split $2 for Beaver and $4 for Coyote Springs since Coyote Springs has lower heat rate

CASE: UE 180/UE 181
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Direct Testimony

July 18, 2006

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

A. My name is Ed Durrenberger. 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/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will discuss an adjustment I propose to the power costs related to coal losses at Boardman

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/302, consisting of 6 pages.

Q. PLEASE DESCRIBE THE COAL RAIL TRANSPORTATION LOSSES THAT PGE HAS INCLUDED IN TESTIMONY.

A. The coal losses I am concerned with are described in testimony in PGE/400, Lesh-Niman on pages 52 and 53. The testimony discusses Powder River basin coal that is brought from Wyoming and Montana to the Boardman, Oregon plant by rail car. The one way distanced is approximately 1,121 miles. This adjustment is for the cost of the coal that the Company reposts is lost in transit.

Q. HOW MUCH COAL DOES THE COMPANY REPORT LOOSING?

A. The Company reports annual coal losses as the result of transport from the mines to the plant of 1% of the coal purchased. The financial consequence of this loss is $354,000 annually.

Q. HOW MUCH COAL IS THIS?

A. In Exhibit Staff/302 page 4, the company reports average annual purchases of coal for the Boardman plant, from 1999 to 2002, of 2.2 million tons. The one percent coal loss represents 22 thousand tons annually that the Company would have to be loosing each year along the rail, nearly 20 tons every mile.

Q. IS THIS A REASONABLE AMOUNT OF COAL LOSS?

A. Rail car coal losses have been studied extensively and the company cited studies supporting coal losses of 1% and more under some circumstances. Whether this is a reasonable loss for the trip from the Powder River Basin to Boardman is a matter of conjecture since the Company's studies of their fuel losses looked at the weight of coal in the cars leaving the mine and compared it to the weight of coal being fed to the power plant and used an annual survey of the fuel pile to account for inventory.

Q. WHAT DO YOU PROPOSE?

A. I recommend this annual adjustment be disallowed in its entirety.

Q. WHY ARE YOU PROPOSING TO DISALLOW THE COMPANY'S ADJUSTMENT?

A. When the Company's coal loss problem was studied several years ago, (*See* Exhibit Staff/302 page 4) three out of the four years of data showed a loss but inexplicably one year showed a net gain. I have misgivings about adding $366 thousand per year to power costs on an old study that produced invalid data 25% of the time.

The same studies that indicated that coal losses from rail cars could be as high as or higher than 1% also discussed the application of control measures that could cost effectively control losses. In light of this and the Company providing no analysis that indicates that allowing over twenty tons of coal dust to escape into the atmosphere as fugitive dust each year is appropriate either economically or environmentally, I find this write-off unsupportable.

Also, there may be issues at the Boardman plant that are contributing to the coal losses. The Company's study doesn't distinguish losses that may occur in transit from losses that occur with furl stock at the plant. The subject merits a more detailed and current investigation.

For these reasons I cannot determine that the coal losses cited are real, cannot be controlled in a cost effective manner and represent an ongoing expense that justifies recovery in power costs

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 180/UE 181
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 18, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues.
OTHER EXPERIENCE:	I have over twenty years of operations and maintenance experience managing a boiler plant in a heavy industrial manufacturing environment. I have also managed manufacturing and production in high tech equipment manufacturing.

CASE: UE 180/UE 181
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 302

Exhibits in Support of Direct Testimony

July 18, 2006

June 6, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 16, 2006
Question No. 468

Request:

With regard to the testimony in PGE/ 400, Lesh-Niman/ pages 52-53, starting on line 10, the coal rail transportation losses; please provide the documentation cited showing the coal losses. Does all the coal purchased and consumed get weighed? Do the weight measuring devices at the mine and at the plant have the same level of accuracy? Are they calibrated and certified regularly? How is the coal pile measured in the study? Was the amount of fuel in the coal pile physically measured such as by a fuel cut off or other means that could account for compaction and settling? Did the actual coal pile size changed significantly (by more than 10%) during the study period? Does the company have any more recent coal rail transportation loss data and, if so, what is the current loss figure?

Response:

Attachment 468-A is an Excel file, "DR_468_Attach A.xls," which provides the calculation of the 1% coal loss factor. Attachment 468-B is a Word file, "DR_468_Attach B.doc," which describes our approach to the calculation.

All coal is weighed, both at the mine and at the pulverizer feeder scales. The scales at the mine are certified (accurate to within ± 0.25%). The scales at the pulverizer feeder scales are also accurate to within ± 0.25% (calibrated quarterly).

In an uncompacted coal pile, the density will vary with height. Therefore, we compact the pile prior to the annual survey, which results in a more uniform density from top to bottom. This maximizes the survey's accuracy.

As can be seen in column f of Attachment 468-A, the coal pile size changed by more than 10% in each of the survey years.

PGE does not have more recent coal rail transportation loss data.

UE 180
Attachment 468-A

Coal Loss Spreadsheet

UE 180

PGE's Response to OPUC Data Request No. 468
Attachment 468-A

BOARDMAN COAL PLANT
100% Plant
Coal Survey vs. Book
(amount in Tons)

	Since Previous Survey		Computed amt	Measured amt. in Coal Pile		Coal Loss		
Year	Purchased at Mine	Coal Burned	Book Inventory before adj.	Survey w/ Base	Survey w/o Base*	Coal Loss	% Difference to Total Deliveries (g/b)	Adjusted Book Inventory
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(I)	
1997	971,897	1,088,905	358,211	389,580	338,185	(20,026)	-2.061%	338,185
*1998	1,680,351	1,700,560	317,976	435,532	384,137	66,161	3.937%	384,137
1999	2,074,808	2,077,006	381,938	396,367	344,972	(36,966)	-1.782%	344,972
**2000	2,420,318	2,251,201	514,090	541,827	490,432	(23,658)	-0.977%	514,089
**2001	2,001,181	2,262,315	252,956	296,207	244,812	15,513	0.775%	252,955
2002	2,461,002	2,262,162	451,796	451,305	399,910	(43,743)	-1.777%	399,910
Total 1999-2002	**8,957,309**	**8,852,684**	**1,600,780**	**1,685,706**	**1,480,126**	**(88,854)**	**-0.992%**	

* New scales installed in 1997 resulted in more accurate measurements and contributed to a large adjustment in 1998.

** Year 2000 and 2001 differences were not booked to inventory because the percentage difference to book inventory was less than the owners' agreement to book the difference only if it differs by 5% or more.

*** A Coal base of 51,395 tons is an established tonnage of unusable coal that is subtracted out of Survey results.

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Attachment 468-B

Explanation of Coal Loss Calculation

Boardman Coal Losses

May 2, 2003

Introduction:
In the coal industry, loss of coal in-transit is a commonly accepted fact, much like the loss of electrical energy over transmission lines. PGE has for a long time adjusted for power line losses in transmission, but has not adjusted for the coal that is lost during transportation and storage. Quantifying the amount of coal that is lost during transport is an imperfect art, but new technologies are improving the accuracy of measuring in-transit loss. PGE is now able to adjust coal transportation losses by a quantifiable amount. For the 2004 RVM, we are now including a 1% coal loss factor in calculating fuel costs at the Boardman Plant.

Background:
Northern Powder River Basin Coal travels by train 1,121 miles from the Campbell Sub in Montana to the Boardman plant, outside of Boardman, Oregon. Once the coal arrives at Boardman, it is stored in open piles until the coal is fed across conveyer belt scales on its way to the boiler. Yearly surveys of the coal pile at Boardman are taken. Typically, there is an inventory discrepancy between the expected amount of coal in the pile (given the amount leaving Campbell Sub minus the amount burned) and actual survey results. This difference is due to several factors, but is primarily attributed to in-transit wind erosion. In-transit wind erosion was intensely studied in the 1970's and early 1980's, with documented losses of between 2 and 3%[1]. Industry standards suggests that 1 to 2% in-transit losses are probable[2]. The difference between the total amount of coal purchased at the mine and ultimately burned at Boardman from 1999 to 2002 averages 1%, well within acceptable industry standards.

Boardman:
Coal loss calculations are performed yearly, coinciding with the annual coal pile survey. The coal loss is the difference between the actual surveyed amount in the coal pile and the expected calculated book inventory amount, before adjustments. The actual amount in the existing pile is determined by surveying the coal pile during Boardman's yearly spring maintenance outage. The survey takes into account both the volume of the pile and its density to calculate total tonnage. At Campbell Sub the coal is loaded into open railcars, then the cars are weighed, supplying the purchase tonnage. At Boardman, the coal is weighed on conveyor belt scales on its way to being burned in the boilers. Implementation of the conveyor belt scales was completed during the 1997 spring outage, improving weight accuracy of coal burned. Purchases since the last survey are added to the adjusted book inventory, amounts burned since the last survey are subtracted from inventory to calculate the book inventory before adjustments.

$$\text{Coal Loss}_{(y)} = \text{Book Inventory}_{(y)} - \text{Adjusted Book Inventory}_{(y-1)} \\ - (\text{Surveyed Amount}_{(y)} - \text{Surveyed Amount}_{(y-1)})$$

If the difference between the survey and the book inventory is greater than 5% of book inventory, book inventory is adjusted to equal survey results. If the difference is less than 5% the book inventory is not adjusted. Starting in 2003 the inventory books will be adjusted to reflect the surveyed amounts yearly, independent of the difference between surveyed and book inventory amounts.

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[1] G.H Denton, R.E. Hassel, and B.E. Scott, "Minimizing In-transit Windage Losses of Olga Low Volatile Coal," (paper presented at the 1972 Coal Show, American Mining Congress, Cleveland, Ohio, May 10, 1982), as cited by S. J. Blubaugh, D. O. Owen, Phd., and A. J. Sobol all of Nalco Chemical Company, in "Mine Applied Dust Prevention for Residual Dust Control" (Paper presented at the EPRI Conference, Pensacola, Florida, January 23-25, 1991.).

[2] K.H. Nimerick and G.P. Laflin, "In-transit Wind Erosion Losses of Coal and Methods of Control, "Mining Engineering, August (1979),1236-1240

CERTIFICATE OF SERVICE

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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 18th of July, 2006.

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