Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

August 7, 2006

Via Electronic Mail and U.S. Mail

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferred Accounting of Excess Power Costs Due to Plant Outage
Docket No. UM 1234

Dear Filing Center:

Enclosed please find the original and two copies of each of the following documents of the Industrial Customers of Northwest Utilities:

Motion to Admit Testimony and Exhibits (Confidential Version) in OPUC Docket No. UM 1234

Motion to Admit Testimony and Exhibits (Redacted Version) in OPUC Docket No. UM 1234

Affidavit of Randall J. Falkenberg in OPUC Docket No. UM 1234

Please return one file-stamped copy of each document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely yours,

/s/ Ruth A. Miller
Ruth A. Miller

Enclosures

cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Motion to Admit Testimony and Exhibits (Confidential and Redacted Versions as indicated below) of the Industrial Customers of Northwest Utilities, and the Affidavit of Randall J. Falkenberg upon the parties, on the official service list shown below for UM 1234, via U.S. Mail and electronic mail.

Dated at Portland, Oregon, this 7th day of August, 2006.

/s/ Ruth A. Miller
Ruth A. Miller

CITIZENS' UTILITY BOARD OF OREGON
CONFIDENTIAL
LOWREY R BROWN
610 SW BROADWAY - STE 308
PORTLAND OR 97205
lowrey@oregoncub.org

CITIZENS' UTILITY BOARD OF OREGON
CONFIDENTIAL
JASON EISDORFER
610 SW BROADWAY STE 308
PORTLAND OR 97205
jason@oregoncub.org

DEPARTMENT OF JUSTICE
CONFIDENTIAL
STEPHANIE S ANDRUS
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us

PORTLAND GENERAL ELECTRIC
REDACTED ONLY
RATES & REGULATORY AFFAIRS
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

PORTLAND GENERAL ELECTRIC
CONFIDENTIAL
DOUGLAS C TINGEY
121 SW SALMON 1WTC13
PORTLAND OR 97204
doug.tingey@pgn.com

RFI CONSULTING INC
CONFIDENTIAL
RANDALL J FALKENBERG
PMB 362
8351 ROSWELL RD
ATLANTA GA 30350
consultrfi@aol.com

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1234

In the Matter of Portland General Electric Company Application for Deferred Accounting of Excess Power Costs Due to Plant Outage.	)	MOTION TO ADMIT TESTIMONY AND EXHIBITS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

Pursuant to Administrative law Judge Kirkpatrick's August 3, 2006 Memorandum, Industrial Customers of Northwest Utilities ("ICNU") moves that the direct testimony and exhibits of Randall J. Falkenberg (ICNU/100-104) and the hearing exhibits that are attached to this Motion (ICNU/200-211) be admitted into the record in this proceeding. Along with this Motion, ICNU is filing an affidavit executed by Mr. Falkenberg attesting that his testimony is true and correct.

Dated this 7th day of August, 2006.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

/s/ Matthew W. Perkins

S. Bradley Van Cleve
Matthew W. Perkins
Davison Van Cleve, P.C.
333 SW Taylor, Suite 400
Portland, Oregon 97204
(503) 241-7242 phone
(503) 241-8160 facsimile
mail@dvclaw.com
Of Attorneys for Industrial Customers
of Northwest Utilities

ICNU Cross Examination Exhibit List

UM 1234 Hearing

NUMBER	WITNESS	A/R	DATE	DESCRIPTION
Cross Examination Exhibits				
ICNU/200	Lesh-Tinker			Excerpt of PGE Response to ICNU DR No. 020 (***Confidential Subject to General Protective Order***)
ICNU/201	Lesh-Tinker			PGE Response to ICNU DR No. 021
ICNU/202	Lesh-Tinker			PGE Response to ICNU DR No. 023
ICNU/203	Lesh-Tinker			PGE Response to ICNU DR No. 030
ICNU/204	Lesh-Tinker			PGE Response to ICNU DR No. 032
ICNU/205	Lesh-Tinker			PGE Response to ICNU DR No. 033
ICNU/206	Lesh-Tinker			PGE Response to ICNU DR No. 034
ICNU/207	Lesh-Tinker			PGE Response to ICNU DR No. 058
ICNU/208	Lesh-Tinker			PGE Response to ICNU DR No. 059
ICNU/209	Lesh-Tinker			PGE Response to ICNU DR No. 064
ICNU/210	Lesh-Tinker			PGE Response to ICNU DR No. 068
ICNU/211	Lesh-Tinker			PGE Response to ICNU DR No. 074

July 19, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 6.1
Dated July 11, 2006
Question No. 020

<u>Request:</u>

Please provide workpapers showing the computation of the outage rates used in MONET. Include all backup data showing each outage (planned or unplanned, etc) and deration (planned or unplanned) considered in the four-year periods used to compute the outage rates used in MONET, including NERC cause code, type of event, duration, energy lost, etc. Provide workpapers showing the derivation of any seasonal outage rate assumptions used. Please provide this information electronically, and in the case of excel spreadsheets, please make sure that all formulas are intact.

Note: ICNU previously submitted this request to PGE as DR 2.14 in UE 180/UE 181.

<u>Response</u>:

PGE objects to this request because it is overly broad and unduly burdensome. However, without waiving its objection, PGE responds as follows:

Attachment 020-A is provided on CD, which contains extensive information on unplanned outages and derations during the Four-Year Period. See files "ThermalFOR2007GRC-Final.xls," "FileSummary.doc," and "Files in this directory tree.xls" for summary statistics and information on how Attachment 020-A is organized. For a discussion of why we use the 2001-2004 period for Beaver 8, see the file "Beaver8EFOR_for2007GRC.doc," which is located in the

"Beaver 8" sub-folder. Attachment 020-A is confidential and subject to Protective Order No. 06-022.

See pages 57-58 from PGE Exhibit 400 in UE 180 for information on our 2007 planned outage assumptions, included as Attachment 020-B.

UM 1234
Attachment 020-A

Confidential and Subject to Protective Order No. 06-022

Provided electronically (CD)

Copy of PGE's response to ICNU data request No. 2.14 in UE 180

CONFIDENTIAL

INFORMATION

OMITTED

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.1
Dated July 19, 2006
Question No. 021

Request:

Regarding PGE/400, Lesh-Tinker/5, line 6, please provide all documents that refer or relate to or support the statement that the rolling four-year weighted average of actual forced outage rates to determine plant availability "dates back to the 1980s."

Response:

PGE objects to this request because it is overly broad and unduly burdensome. Without waiving objection, PGE responds as follows:

Attachment 021-A contains a Staff memorandum from 1984 recommending the use of the four-year rolling average for rate-making.

UM 1234
Attachment 021-A

OPUC Staff Policy Statement

STATE OF OREGON 1859
VICTOR ATIYEH GOVERNOR

PUBLIC UTILITY COMMISSIONER OF OREGON

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

July 31, 1984

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

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

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

AUG - 1 1984

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

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

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

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

Data Request

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

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

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

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

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

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

WGWarren

William G. Warren
Manager
Energy Division

ger/05611

Attachments

cc: Roger Colburn
Scott Girard

DATE: 05/18/84

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

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

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

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

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 Troj a little differently because PGE collects data for Trojan to meet NR requirements, and such data differs from that collected for coal fir 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 o 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 th 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 shut-downs 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.

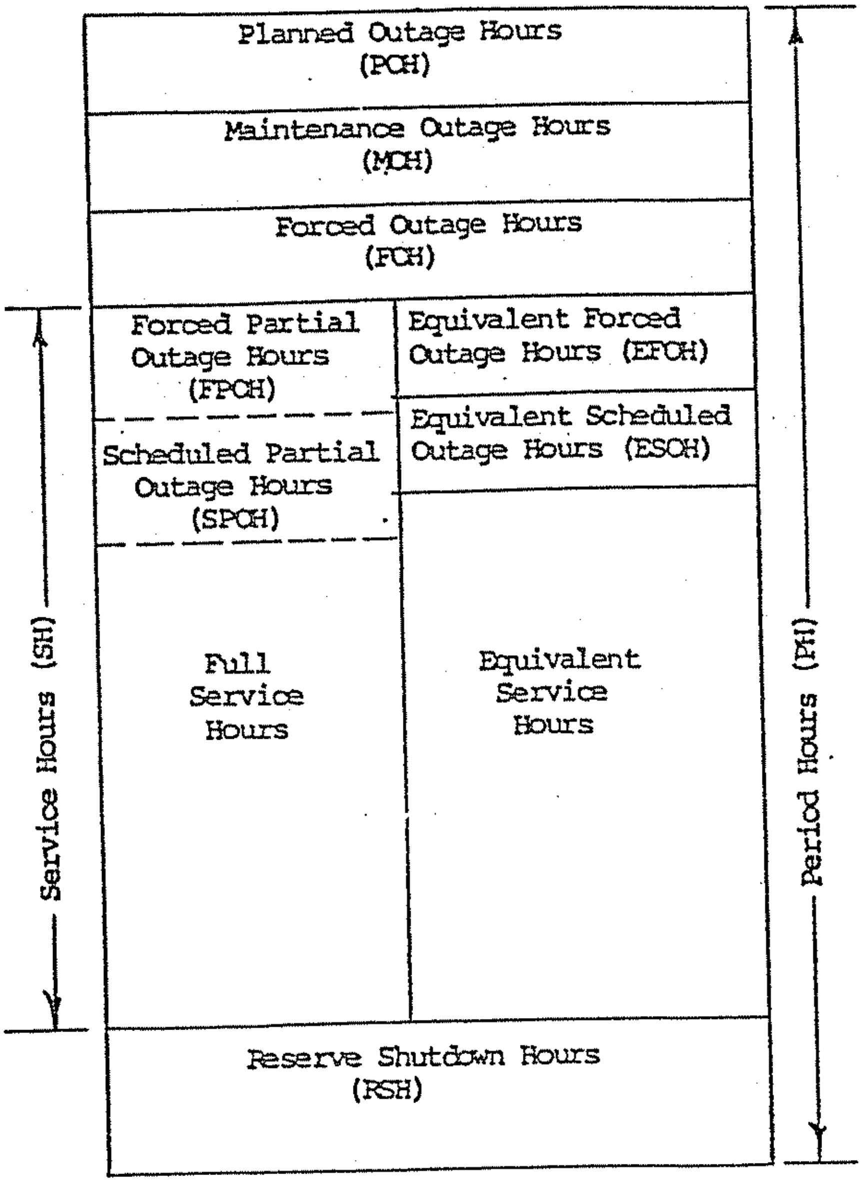
MW Net - Megawatts Net - Net megawatts available from a unit or plant excluding station use. For our purpose here:

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

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.

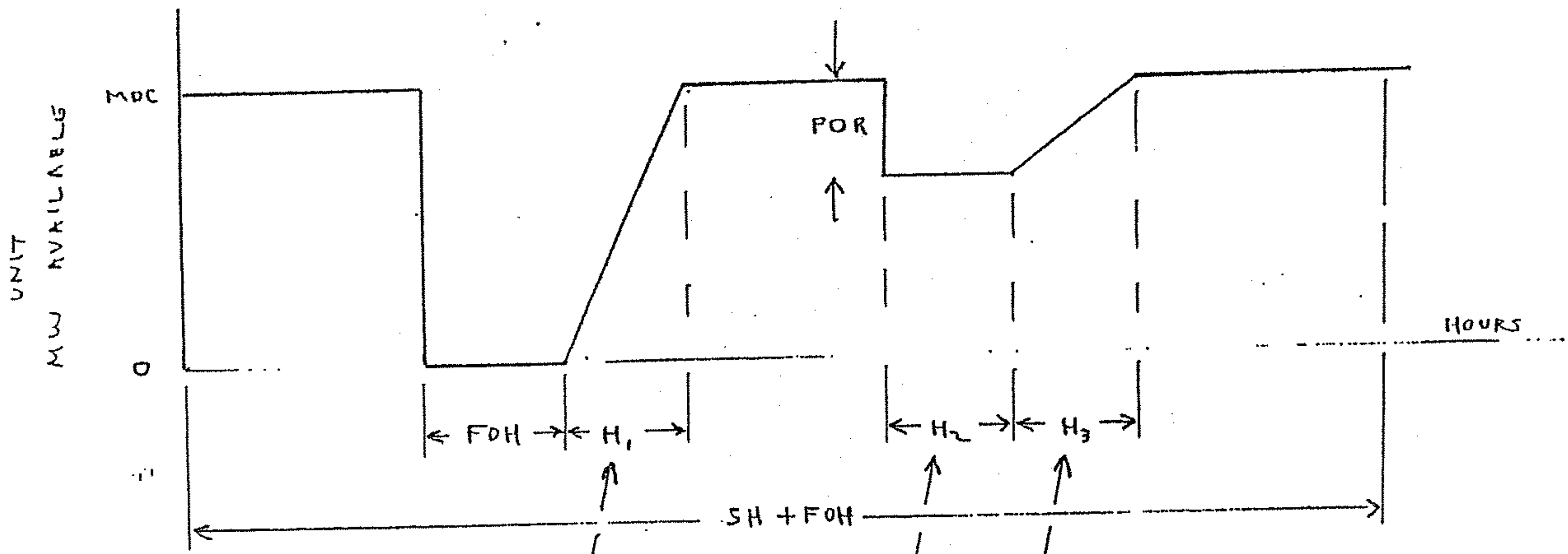
The procedures for calculating EFOH and ESOH are illustrated on the following two pages. The procedures are alike. It can be seen that EFOH and ESOH are the sum of equivalent outage hours for several partial forced or partial scheduled outages.

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



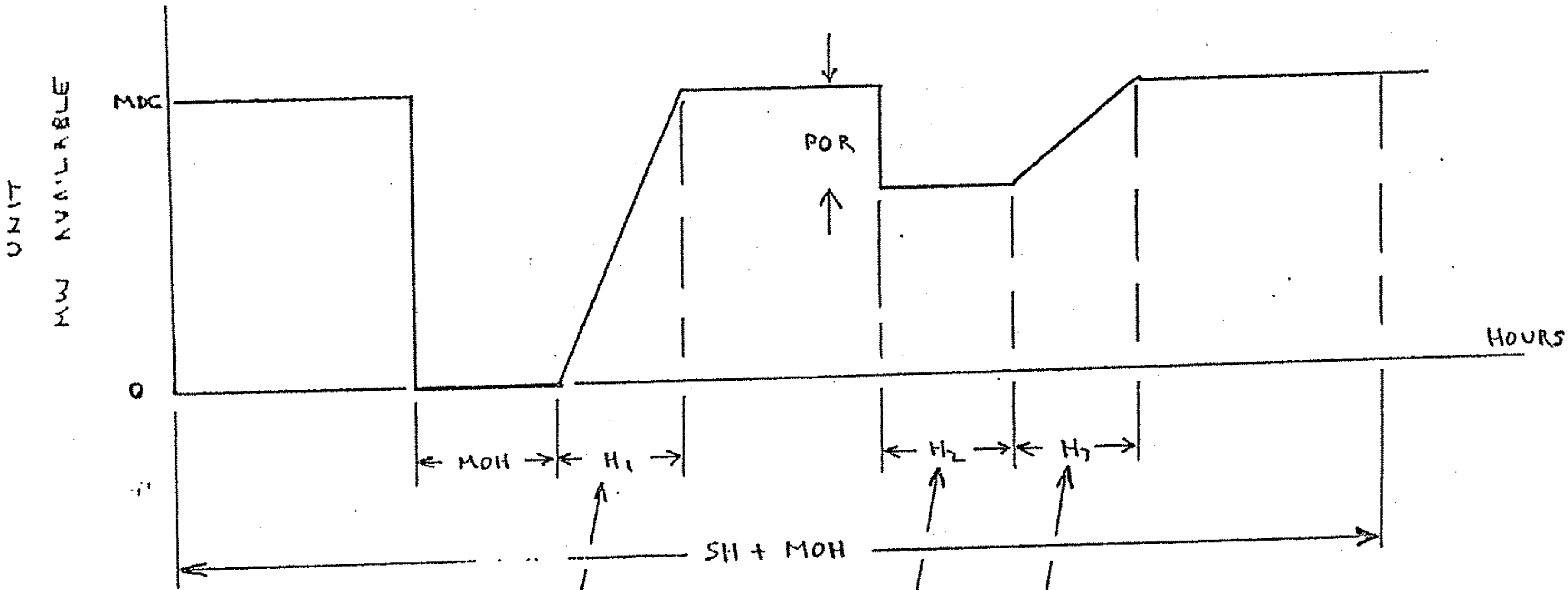
$$EFOH_1 = \frac{1}{2} \times H_1$$

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

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

$$EFOH = EFOH_1 + EFOH_2 + EFOH_3$$

Figure 3
Equivalent Scheduled Outage Hours Illustration



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

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

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

$ESOH = ESOH_1 + ESOH_2 + ESOH_3$

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

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

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

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

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

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

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

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

THERMAL PLANTS

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

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

Portland General Electric

Trojan

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

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

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

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

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

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

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

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

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

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

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

Boardman

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

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

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

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

Colstrip #3

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

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

Colstrip #4

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

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

Idaho Power Company

Valmy 1

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

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

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

Valmy 2

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

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

Pacific Power & Light

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

Jim Bridger 1-4

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

Dave Johnston 1-4

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

Wyodak

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

Centralia 1-2

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

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

PLANNED AND ECONOMY OUTAGES

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

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

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

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

GENERAL INFORMATION

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

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

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

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

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

bjs/1710m

Attachments

Appendix A
Pg. 1

Thermal Plant Performance

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

[1]EOR in percent

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

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

jcp/1014j-1

Appendix A
Pg. 2

Thermal Plants

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

[1]Nameplate rating.

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

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

jcp/1014j-2

Appendix A
Pg. 3

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

[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]FOR, Forced Outage Rate

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

jcp/1014j-3

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.3
Dated July 19, 2006
Question No. 023

Request:

Please identify the specific statements in Staff or intervenor testimony that PGE intended to rebut with the discussion of SB 408 on pages Lesh-Tinker/21-23 of PGE's rebuttal testimony.

Response:

See CUB Exhibit 100, page 2 lines 8-11. Staff and ICNU did not consider SB 408 impacts, see PGE Exhibit 404, pgs. 16-17, and PGE Exhibit 405, pg. 1.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.10
Dated July 19, 2006
Question No. 030

Request:

What is the current status of the Boardman plant? Is it running and, if so, at what loading levels? How long has it been up and running? When did the outage end? Did additional outages occur since that time?

Response:

Current Status as of August 1, 2006: Running at full load

Boardman has been on-line since June 28, 2006; it was released for dispatch July 1, 2006.

For deferral purposes, the outage ended on February 5, 2006. Additional outages have occurred since the end of the deferral period.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.12
Dated July 19, 2006
Question No. 032

Request:

Please provide all root cause analyses conducted related to the Boardman outage.

Response:

There is a Root Cause Analysis of the Boardman LP1 low pressure rotor cracking being performed. PGE has initiated and participated in a multi-disciplinary and multi-company effort to examine potential failure scenarios and determine the root cause and contributing causes of the rotor cracking. The effort requires operational measurements by a consultant firm, scheduled for August, to fully complete its investigation. Additionally, the original equipment manufacturer is conducting its own proprietary analysis of the cracking.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.13
Dated July 19, 2006
Question No. 033

Request:

To the extent Boardman was on outage after February 5, 2006, please explain why PGE did not seek to include the associated replacement power costs in the deferral or, alternatively, why it did not file a new deferral for those costs.

Response:

February 5, 2006, was the date PGE deemed the original outage concluded, see PGE Exhibit 100 page 1. PGE has no request pending for the subsequent outage.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.14
Dated July 19, 2006
Question No. 034

Request:

Please explain why PGE did not file a deferral related to the Boardman outage prior to November 18, 2005.

Response:

The following is from PGE's Application for Deferred Accounting of Excess Power Costs Due to Plant Outage filed November 18, 2005:

> On October 22, 2005, a vibration was detected in the rotor of the low-pressure turbine rotor at Boardman. The plant was taken off line to determine the cause of the vibration. The turbine has been partially disassembled and reassembled; however, repeated efforts to rebalance the rotor have been unsuccessful. The plant continues to experience a temperature sensitive and load sensitive rotor vibration, which makes continued operation of the low-pressure turbine unsafe and potentially destructive. Visual inspection of the rotor indicates no specific problem. After the most recent attempts to run the turbine were unsuccessful PGE has decided to remove the rotor and perform non-destructive examination of it. The actual repair time is also unknown at this time but the plant may not be operational until the end of January 2006, or later.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.38
Dated July 19, 2006
Question No. 058

Request:

Does PGE have any property on or near flood planes? If so, does it consider a one in one-hundred year flood such an unlikely event that it takes no steps to minimize either the cost or damage of such an event?

Response:

PGE carries flood insurance coverage within our main "All Risk" property program. The program provides $133 million in flood limits subject to a $2,500,000 deductible. The program is not limited to 1 in one-hundred year floods. Further, such insurance would not cover costs associated with replacement power - the subject of this docket.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.39
Dated July 19, 2006
Question No. 059

Request:

Reference PGE/400, Lesh-Tinker/14, lines 16-22. Does PGE contend that it has no cost included in rates such as costs for insurance, redundancy, back up systems, etc., that have a likelihood of one in one-hundred years or less?

Response:

No.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.44
Dated July 19, 2006
Question No. 064

Request:

Reference PGE/400/page 24, lines 1-11. Please explain what assumptions PGE makes regarding plant outages in making its decisions to purchase power. Does the Company assume outages will never occur, or does it assume some outages will occur and make allowances for such outages in its purchasing decisions?

Response:

PGE's power operations group—the group that makes energy purchase and sales decisions within PGE—does not consider a forced (a.k.a. unplanned) unit outage component in its energy procurement strategy until a unit actually experiences an unplanned outage. This decision is not an oversight, but instead a thoughtful strategy based on operational experience.

To include a forced outage rate in PGE's purchasing strategy, in essence, would mean that PGE would regularly carry length (i.e., extra power) into the real-time market in the amount of the forced outage rate. This length, if an outage were not to occur, would have to be sold into the wholesale energy market to balance PGE's system. As such, including a forced outage rate would create an undesired trading position for PGE the majority of the time.

Furthermore, in the event PGE experienced an unplanned outage, the volume of power associated with the historical forced outage rate would not be sufficient to cover the majority of any large plant outage and PGE would still have to rely on purchases from the spot market.

PGE does, however, take extra precautions during peak periods where the wholesale market conditions are expected to be tight. In such circumstances, PGE will generally carry length into the day-ahead market and real-time market to cover potential contingencies such as load overruns or unit underperformance.

Finally, there are several other potential energy resources available to PGE in the event of an emergency. These options include operating reserves, capacity contracts, and dispatchable standby generation (DSG). The capacity contracts are available on a seasonally limited basis. Similarly, DSG is limited on an annual hourly basis. Both are discussed more fully in UE 180, PGE Exhibit 300. PGE carries operating reserves as required by WECC/NERC guidelines. These include both spinning and supplemental reserves. Reserve requirements for thermal and hydro resources are 7% and 5% respectively, of which half must be spinning.

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.48
Dated July 19, 2006
Question No. 068

Request:

Reference PGE/400, Lesh-Tinker/24, lines 1-11. Does PGE contend that any outage at Boardman was unforeseeable, or just this particular outage? Please explain. Had the repair only taken a few weeks, would PGE have considered this to be a foreseeable outage? Please explain whether it was the outage event itself or the time it took for repair that PGE considered unforeseeable.

Response:

Forced outages by definition are not subject to prediction. NERC defines a forced outage as follows:

> 1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to *unanticipated* failure. (NERC Glossary of Terms Used in Reliability Standards, May 2, 2006) (emphasis added)

August 1, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 7.54
Dated July 19, 2006
Question No. 074

Request:

Reference PGE/400, Lesh-Tinker/24, lines 14-15. Has PGE inquired whether any counter party would consider providing outage insurance? If not, explain why not.

Response:

Yes, PGE has in the past solicited premium quotes for Generating Plant Forced Outage Insurance. This type insurance protection is designed for generating owners to protect against long-term unplanned extended outage. Coverage is triggered by a discrete event of physical loss or damage to insured property that results in a forced outage at the insured generating facility.

With this type of coverage there is a time element deductible [waiting period] before the policy will begin to pay its daily indemnity payments to the insured. Waiting periods for this type of coverage typically range from 30 to 180 days.

As a result of these long deductible periods; this type of coverage yields little economic value to PGE since typically the majority of economic loss is usually sustained within the deductible [waiting period] of the policy.

For example, in 2002 we solicited a long term outage insurance quote for Boardman, the terms were as follows:

Annual Premium: $2,000,000

Deductible: 60-days

Daily indemnity limit: $150,000

Based on the above terms, assuming the premium remained constant, along with the deductible and daily limit, PGE would have recovered approximately $3 million for the deferral period. This is much less than the replacement power costs incurred ($45.7 million) and less than the total premium amounts over the years 2002-2006 ($10 million).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1234

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferred Accounting of Excess Power Costs Due to Plant Outage.	)	AFFIDAVIT OF RANDALL J. FALKENBERG

I, Randall J. Falkenberg, being first duly sworn on oath, depose and say:

1. My name is Randall J. Falkenberg. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU"). My business address is: PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350.

2. I sponsored pre-filed testimony and exhibits on behalf of ICNU in Oregon Public Utility Commission Docket No. UM 1234. Specifically, my pre-filed direct testimony and exhibits, ICNU/100-104, were filed on June 1, 2006.

3. My testimony and exhibits that were previously filed are true and accurate, and no corrections need to be made. If I were asked the same questions today, my answers would be the same.

I HEREBY DECLARE THAT THE ABOVE STATEMENT IS TRUE TO THE BEST OF MY KNOWLEDGE AND BELIEF, AND THAT I UNDERSTAND IT IS MADE FOR USE AS EVIDENCE AND IS SUBJECT TO PENALTY FOR PERJURY.

SIGNED THIS 3 day of August, 2006, at Sandy Springs, Georgia.

Randall J. Falkenberg

SUBSCRIBED AND SWORN to before me this 3rd day of August, 2006.

NOTARY PUBLIC FOR GEORGIA

My Commission Expires: September 13, 2009

NATHANIEL CAINES NOTARY EXPIRES GEORGIA September 13, 2009 PUBLIC COBB COUNTY