Oregon

Kate Brown, Governor

Public Utility Commission
3930 Fairview Industrial Dr. SE
Salem, OR 97302
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

May 28, 2015

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97308-1088

RE: Docket No. UE 294 – In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision. (Power Cost)

Enclosed for filing is Public Utility Commission Staff Opening Testimony (Power Cost).

/s/ Kay Barnes
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: Kay Barnes@state.or.us

PUBLIC UTILITY COMMISSION
OF OREGON

UE 294

STAFF OPENING TESTIMONY OF

JOHN CRIDER

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision.

(POWER COST)

May 28, 2015

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

May 28, 2015

Q. Please state your name, occupation, and business address.

A. My name is John Crider. My business address is 3930 Fairview Industrial Dr. SE., Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Staff's analysis and concerns regarding the Power Cost portion of Portland General Electric's rate case in this filing.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

1. Staff/101………………… Qualification Statement
2. Staff/102………………… Staff Memo Re: Forced Outage Calculation
3. Staff/103………………… EIA Capacity Factor Table
4. Staff/104………………… SEC 8K Filing (Coyote Springs Outage)
5. Staff/105………………… PGE Load/Resource Balance 2009-2015

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, COYOTE SPRINGS FORCED OUTAGE RATE

Q. Please describe the forced outage rate for a generating plant.

A. According to the North American Electric Reliability Council (NERC), the body authorized to set national reliability standards for the electric power industry, a forced outage occurs when a generating plant is removed from service due to an emergency or other unanticipated equipment failure.[1] Forced outages are differentiated from maintenance outages based on their unanticipated, and hence unplanned, nature. The Forced Outage Rate (FOR) is a measure of the likelihood of a generating unit being unavailable for service when called upon due to an unplanned (typically an emergency) shut down of the plant.

Q. How is a typical 'FOR' calculated?

A. In general, a forced outage rate is expressed on an annual basis as the ratio of the number of hours the plant was unavailable due to an unplanned, emergency outage divided by the sum of the total service hours and unplanned outage hours for that unit during the year. Another way of expressing this idea is that the FOR is a ratio of:

$$\boldsymbol{FOR} = \frac{\text{Hours the unit is unavailable due to unplanned outage}}{\text{Total hours the unit was expected to be available for a given year}}$$

Q. Is this the only such measurement of reliability for a unit?

A. No. NERC defines many different reliability measurements related to outages and outage rates. FOR, is the simplest and perhaps most common measure. However, by including or excluding the number of hours related to certain

[1] NERC Glossary of Terms used in NERC Reliability Standards (updated May 19, 2015) at 37, which can be found at: http://www.nerc.com/files/glossary_of_terms.pdf

events such as maintenance outages or derating, different metrics are created and defined[2].

Q. Other than 'FOR', what other relevant reliability metrics does NERC utilize?

A. By including in the FOR calculation the hours that the unit is unexpectedly derated (that is, hours that the unit is forced to generate at levels lower than its maximum due to maintenance issues), the new calculation is referred to as the "effective forced outage rate", or EFOR. This metric provides a measure not only of simple unit availability (as FOR does) but also gives an indication of how close to maximum output the unit can be operated. In periods of low demand on the system, there may be no reliability impact due to a unit being derated because it is not being called upon to generate at maximum to serve load. However, in periods of high demand when the unit is needed at full power; derating becomes more critical and will influence both operations and NVPC. In both cases, a lower value for the metric (FOR or EFOR) means a greater expectation that the unit will be available when called upon.

Q. Does the commission have a standard method for determining a plant's 'FOR'?

A. The Commission has used a standard calculation for the determination of thermal plant FOR since 1984.[3] This basic method uses a rolling annual

[2] See IEEE Standard 762 for complete set of reliability measures and definitions (http://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf)
[3] See 1984 Memorandum from William Warren with attachments, filed in Docket UM 1355 as Staff Exhibit 102. This memorandum with exhibits is attached as Exhibit Staff/102.

average of the actual unplanned outage hours over the last 48 months in order to determine the FOR. In Order Nos. 09-479 and 10-414 issued in Docket UM 1355, the Commission clarified how the calculation should account for unplanned outages of extreme length. In Order No. 10-414 the Commission gave explicit instruction on how FORs for coal plants shall be calculated in Commission proceedings.

Q. Describe the primary contested issue in that docket.

A. The primary issue in Docket UM 1355, as noted in Commission Order No. 10-414[4] was the determination of a coal unit's FOR in the event of an extended unplanned outage during the preceding 48 months.

Q. Why is this issue important?

A. Each year every utility forecasts its upcoming test year power cost projection (Net Variable Power Cost, or NVPC) which, upon Commission approval, is then collected through rates. The power cost projection is a result of modeling the economic dispatch of resources to meet load over the entire test year, and a summing of the costs to do so. The NVPC is directly affected by the FOR assumed for each plant. An increase in a plant's FOR translates into an increased likelihood of that plant being unavailable at some time during the model run. Any change in availability translates into a potential change in the NVPC. Therefore, an accurate projection of NVPC is in part dependent on the FOR accurately modeled for each plant.

[4] Commission Order No. 10-414, pp. 3-6.

Q. How did the Commission resolve this issue in Docket UM 1355?

A. The Commission reaffirmed the current and historical practice of using a 48-month rolling average but gave special consideration of outlier years in the data. In the case that a plant's FOR is either lower than the 10th percentile or greater than the 90th percentile of NERC-reported FOR of a similarly sized unit in a given year, then the outlying year's data is discarded from the 48-month rolling average. In its place, the Commission ordered that the discarded data should be replaced by a 20-year rolling average or the lifetime average if the plant has less than 20 years of operation.[5]

Q. Did the Commission order that this method be applied for all generation plants?

A. No. The Commission ordered the 48-month FOR rolling average, with modifications for outlying years, only for coal plants. The Commission did not address the specific issue of modeling FORs for baseload natural gas-fired plants.

Q. Why was the Docket UM 1355 method for excluding outliers from the FOR applied only to coal plants?

A. The original FOR calculation used in Oregon was designed in 1984.[6] At that time, all of the baseload plants owned by utilities serving the state were coal, or in the case of Trojan, nuclear. Until very recently, the price of natural gas made baseload natural-gas fired plants uneconomic compared to coal plants. It was not until the commercial operation of PGE's Port Westward plant in 2007 that

[5] See Order No. 10-414 at 5.
[6] See Exhibit Staff/102.

the Company's portfolio included baseload operation of a natural gas-fired plant.

Q. What do you mean by 'baseload' in this testimony?

A. In this testimony, a baseload plant is one that conforms to the definition provided by the U.S. Energy Information Agency (EIA) in its glossary of electricity terms:

> *A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.*[7]

Q. Is there an operational metric that helps identify a baseload plant from a non-baseload plant?

A. Yes. A plant's capacity factor (CF) is a reasonable measure of baseload operation. The capacity factor compares the total annual energy (MWh) output of a plant to its maximum potential output. Baseload plants typically operate with CF of 30 percent or more, whereas non-baseload plants typically operate with a CF under 20 percent.[8]

Q. Based on its capacity factor, would you consider Coyote Springs a baseload unit?

A. Yes. According to the Company's 2012 Energy Information Agency Form 923 filing,[9] the unit operated at over a 30 percent capacity factor for nine months out of the year indicating baseload operation, similar to a coal plant. Further,

[7] U.S. EIA Glossary of Terms, which is available at: http://www.eia.gov/tools/glossary/index.cfm.
[8] See Exhibit Staff/103 (from Electric Power Monthly, April 27, 2015, Table 6.7.A).
[9] See http://www.eia.gov/electricity/data/eia923/ 2012 report, Page 4 Generator Data at lines 1624-5

since the forecasted natural gas price in the AUT test year is below the 2012 actual gas price, one would reasonably expect Coyote to dispatch even more in the 2016 model than it did in 2012.

Q. How is the forced outage rate for baseload natural gas-fired plants currently modeled by the company in MONET?

A. The Company has two baseload natural gas-fired plants: Coyote Springs and Port Westward.[10] The Company uses the EFOR metric for these two units. In discussing the forced outage rate for these two units, Staff uses the more generic term "FOR", but acknowledges that the Company uses the EFOR metric.

Q. What is Staff's issue with the modeling of EFOR specifically for Coyote Springs?

A. Coyote Springs experienced an extended outage in 2013. In fact, the plant was unavailable more than it was available for service during that year due to a single event.[11] Inclusion of these hours of down time in the EFOR calculation leads to a very large EFOR.

Q. For purpose of comparison, what is a typical EFOR range?

A. According to NERC's Generating Availability Data System (GADS)[12] in the years 2007-2011 (the last published report) the range for EFOR for all plants of all fuel types reporting was about 6.6 percent - 10.1 percent with an average of

[10] Beaver operated as a baseload plant during the 1990s but is no longer economically operated as a baseload unit.
[11] See Exhibit Staff/104.
[12] NERC's Generating Availability Data System, available at: http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

7.8 percent. The EFOR used by PGE to model Coyote Springs is an order of magnitude of order greater than the highest EFOR in this range because it includes the 2013 outlier.

Q. What is the effect of this large EFOR assumed for Coyote Springs in the model?

A. The effect in the modeling is that the plant will be assumed unavailable for generation during a significant portion of the hours it could be generating. The model will use the large EFOR to assume the plant is experiencing an outage and thus the model will not dispatch the plant for generation.

Q. Can this reduction be seen in the model output?

A. Yes. A comparison of the MONET output for the 2013 test year Annual Update Tariff (AUT) and the current 2016 test year AUT shows a decrease in Coyote production (MWh) of roughly five and one-half percent despite a gas price that is cheaper on average by one-third in the current AUT than that assumed in 2013.

Q. To what degree does the assumed EFOR for Coyote Springs affect NVPC?

A. To roughly estimate the effect that this large EFOR for Coyote Springs has on overall NVPC, I ran the MONET model replacing the current Coyote EFOR with that used in the 2013 AUT (prior to the extended outage in 2013). Re-running the model for the 2016 test year with this one change resulted in an approximate $3 million reduction in NVPC.

Q. How does Staff compare the Coyote Springs natural gas-fired plant to a typical coal plant?

A. With the exception of the fuel type, the plants are quite similar. Coyote Springs has a capacity of about 240 megawatts, similar in size to a small-to-mid sized coal plant. As mentioned previously in my testimony, the Company's MONET April update shows that the unit as modeled operated at a high capacity factor for nine months out of the year indicating baseload operation, similar to a coal plant. Due to its functional and operational similarity to a coal plant, Staff believes it is appropriate to treat Coyote Springs in a similar fashion to a coal plant when determining outage rates.

Q. Does Staff find that data outliers should be excluded from the FOR calculation for Coyote Springs?

A. Yes. The inclusion of data outliers adversely affects the forecast of NVPC.

Q. Please explain the effect that data outliers have on the forecasted NVPC.

A. Generally speaking, including an unusual outage event in the calculation of an average outage rate will unreasonably increase the average FOR and subsequently increase the NVPC projection. Power cost calculations are expected to reflect a normalized view of costs. Normalized, in this sense, means that some years will project costs higher than normal and some years will project costs less than normal, but over time these diversions from normal will essentially balance each other. Abnormal or extreme outages skew the average calculation in an unreasonable manner by giving undue weight to the abnormal event. The resulting NVPC will then be overestimated and may result in overpayment by ratepayers. These are the same concerns that led the Commission to previously revise the FOR methodology for coal plants, and Staff believes the rationale also applies to other baseload generation plants, irrespective of fuel source. Staff thus contends that the method adopted by the Commission for excluding outliers from forced outage rates for coal plants is also appropriate to apply to baseload natural gas-fired plants.

Q. What would be the effect of the Commission's finding that baseload natural gas-fired plants must be treated similar to a coal plant under Docket UM 1355 in regard to determining FOR?

A. Generally, FOR would reflect the appropriate normalized outage rate for modeling purposes. Specifically, in this case, if the Commission were to view Coyote Springs as functionally similar to a coal plant for the purpose of determining forced outage rate, the Commission's treatment of outlier data as set out in Order No. 10-414 should be applied to the determination of EFOR for Coyote Springs. Application of the order would result in the data for year 2013 being discarded from the calculation as an outlier, and the EFOR being recalculated as described in the order. The Company would then re-compute the test year NVPC using the substituted EFOR value and re-running the MONET model.

Q. Is this Staff's recommendation?

A. Yes, Staff recommends that for the purpose of determining the forced outage rate for Coyote Springs, the Commission require PGE to exclude outliers from the calculation. Coyote Springs, a baseload natural-gas-fired plant, is the functional equivalent of a baseload coal plant, and therefore PGE should be required to apply the methodology for the coal-plant forced outage rate calculation as described in Order No. 10-414 on an ongoing basis. Staff further recommends that the revised FOR be modeled in MONET and the model re-run in order to calculate the effect of this one change on NVPC.

ISSUE 2, SUPER PEAK CONTRACT

Q. What is the Super Peak contract?

A. According to PGE, the Super Peak Energy Purchase contract is a simple energy purchase over the super-peak hours (hours 2 PM to 9 PM each day except Sunday).

Q. When was the Super Peak contract first utilized in the calculation of NVPC?

A. The cost associated with this Super Peak contract was initially incorporated in the 2011 AUT.

Q. Why was the Super Peak contract needed?

A. The Company's least-cost planning has historically relied on market transactions for meeting load in order to defer large investments in generation plants. The Super Peak capacity contract was secured as the least-cost, least-risk solution for supplying enough capacity to serve load during the Company's peak load hours in August and September. In the past, without the contract PGE would be forced to serve the peak load with short term market purchases which would result in a higher cost to customers.

Q. Has there been a significant change to the company's generation fleet since 2011?

A. Yes. As can be seen in Exhibit Staff/105, the deficiency between the Company's load obligation and the capacity of its generation fleet has been decreasing as the Company adds new resources. For the immediate future, according to the charts, the Company projects a surplus of resources as compared to load. In large part this is due to the addition of the Port Westward II (PW2) plant and the planned addition in 2016 of the Carty plant to PGE's generation portfolio.

Q. How does this resource sufficiency relate to the Super Peak contract?

A. The original need for the contract was to ensure PGE's ability to serve load during the peak load hours of the summer. Because PGE's generation fleet did not have sufficient capacity to deliver enough energy to serve load during the highest demand hours, the Company instituted the contract to cover this potential shortfall. With the addition of Carty and PW2 plants, going forward PGE will be able to meet the peak load demand from its own resources, thereby negating the need for the Super Peak contract.

Q. Does the MONET modeling provided by the Company support this assertion?

A. Yes. The output from the latest submitted MONET modeling run shows that the unused capacity of PW2 alone during August and September is greater than the energy purchased through the Super Peak contract during those months. When also considering the additional capacity from the Carty plant, which is assumed online by June 2016, the model results show that the two plants together provide unused capacity at a level nearly double the energy purchased through the Super Peak contract.

Q. How does the cost of the contract compare to the cost of generation from Carty or PW2?

A. On a per-MWh basis, the cost of the Super Peak contract is almost twice the average production cost at either plant, based on the MONET output.

Q. What is Staff's recommendation regarding the Super Peak contract?

A. Staff believes the evidence shows the Super Peak contract to be neither least-cost nor necessary to serve load during the 2016 test year. Staff recommends that the Company provide a MONET modeling run with this contract removed. If the result of the new modeling run shows that PGE's load obligations can be met at a lower NVPC without the Super Peak contract, validating the evidence presented in this testimony, then the cost of the contract should be removed from this proceeding's MONET modeling and the NVPC recalculated to reflect this.

Q. What is your estimate of the impact of the removal of the super peak contract on the NVPC?

A. I changed the Super Peak contract modeled capacity to zero and re-ran the MONET model. With no other input changes, the model returned an NVPC calculation of about $250,000 less than the original model run.

Q. Please summarize Staff's recommendations

A. Staff has identified two issues, each resulting in what Staff believes is an overestimation of NVPC for the test year (2016). In Issue 1 Staff believes the current method of EFOR calculation for the Coyote Springs generation unit results in a significantly higher-than-average forced outage rate being modeled in MONET. The high forced outage rate results in a less-than-optimal dispatch solution, and consequently an overestimate of NVPC. Staff recommends applying to Coyote Springs the FOR method for excluding outliers that the Commission has already adopted for baseload coal plants through Docket UM 1355. In Issue 2 Staff notes that the Super Peak contract is no longer needed with the addition of over 600 MW of new thermal capacity to PGE's generation fleet. Staff recommends removing this contract from the test year modeling and to recalculate the NVPC estimate.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

May 28, 2015

WITNESS QUALIFICATION STATEMENT

NAME: JOHN CRIDER

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR UTILITY ANALYST, ELECTRIC RESOURCES AND PLANNING

ADDRESS: 3930 FAIRVIEW INDUSTRIAL DR. SE, SALEM, OR 97302

EDUCATION: BACHELOR OF SCIENCE, ENGINEERING, UNIVERSITY OF MARYLAND

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2012. My current responsibilities include analysis and technical support for electric power cost recovery proceedings, with an emphasis on variable power costs and purchases from qualifying facilities. Prior to working for the OPUC I was an engineer in the Strategic Planning division for Gainesville Regional Utilities (GRU) in Gainesville, Florida. My responsibilities at GRU included analysis, design and support for generation economic dispatch modeling, wholesale power transactions, net metering, integrated resource planning, distributed solar generation and fuel (coal and natural gas) planning. Previous to working for GRU, I was a staff design engineer for Eugene Water & Electric Board (EWEB) where my responsibilities included design of control and communications system in support of water and hydro operations.

I am a registered professional engineer in both Oregon and Florida.

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

May 28, 2015

PUBLIC UTILITY COMMISSIONER OF OREGON

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

July 31, 1984

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

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

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

AUG - 1 1984

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

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

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

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

Data Request

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

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

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

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

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

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

WGWarren

William G. Warren
Manager
Energy Division

ger/05611

Attachments

cc: Roger Colburn
Scott Girard

DATE: 05/18/84

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

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

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

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

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

PUBLIC UTILITY COMMISSIONER OF OREGON
INTER-OFFICE CORRESPONDENCE

(NOT FOR MAILING)

DATE: July 18, 1984

TO: Bill Warren

FROM: Tom Harris

SUBJECT: Thermal Plant Performance

INTRODUCTION

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

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

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

DEFINITIONS

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

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

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

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

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

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.

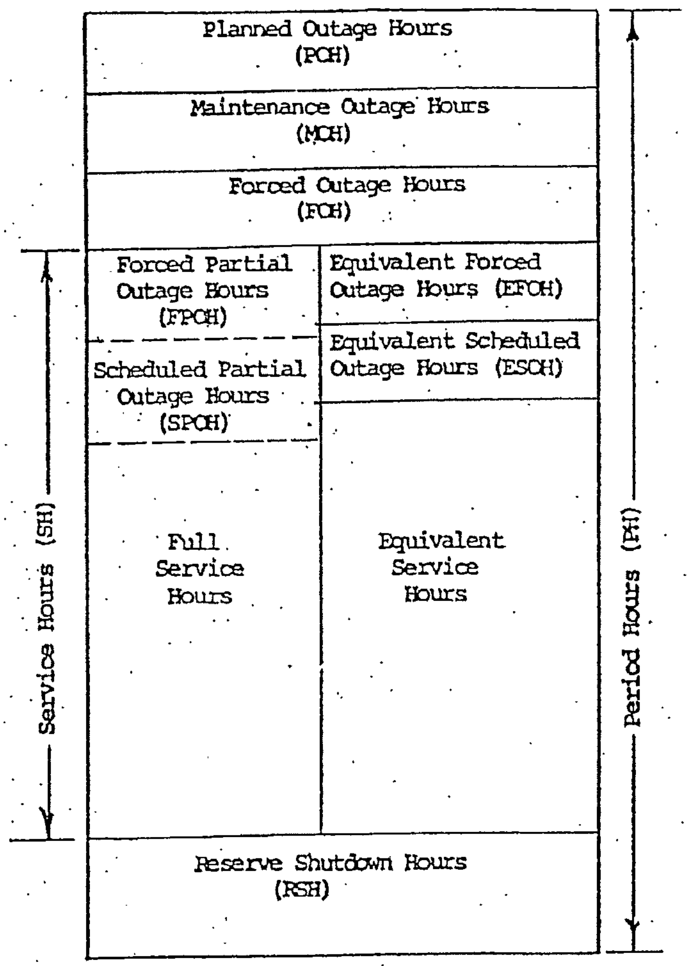
MW Net - Megawatts Net - Net megawatts available from a unit or plant excluding station use. For our purpose here:

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

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

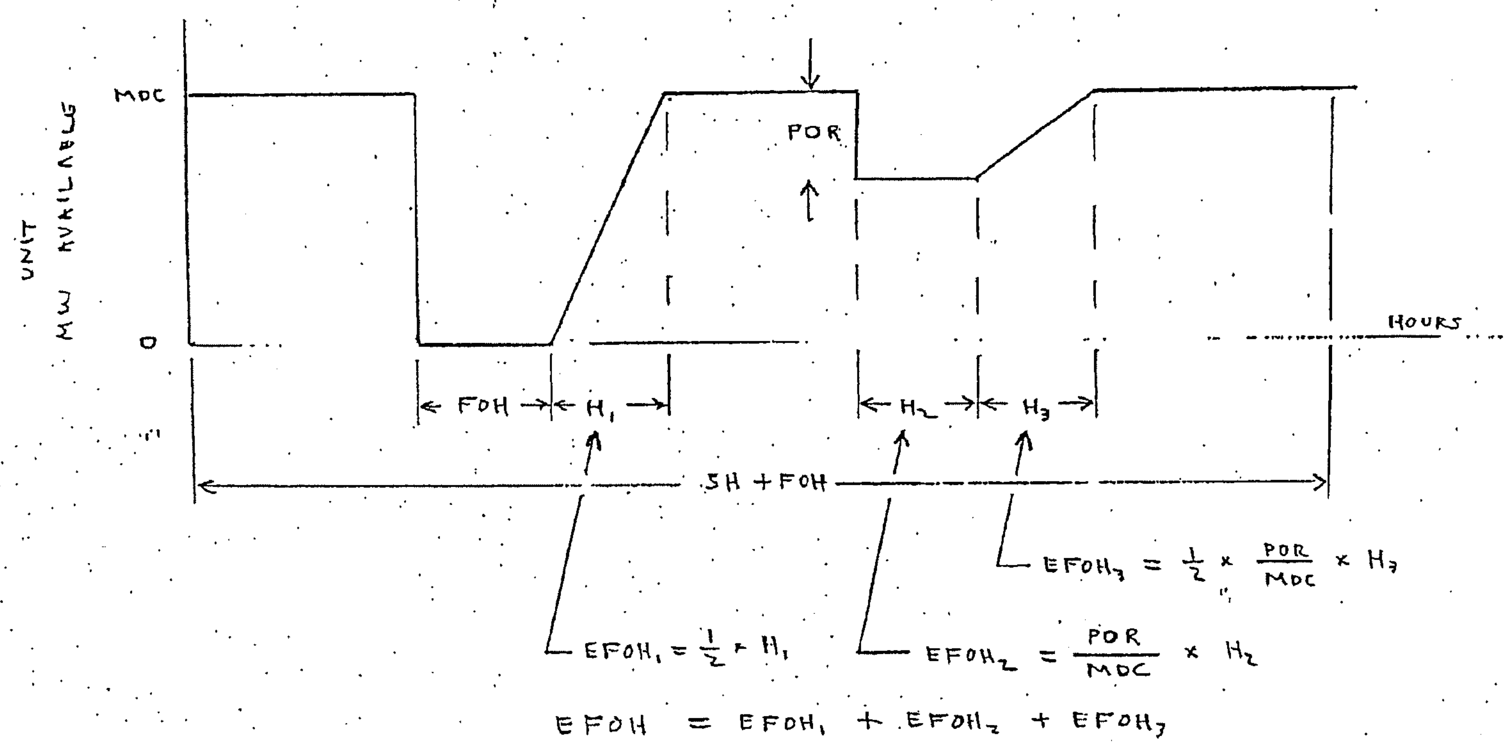
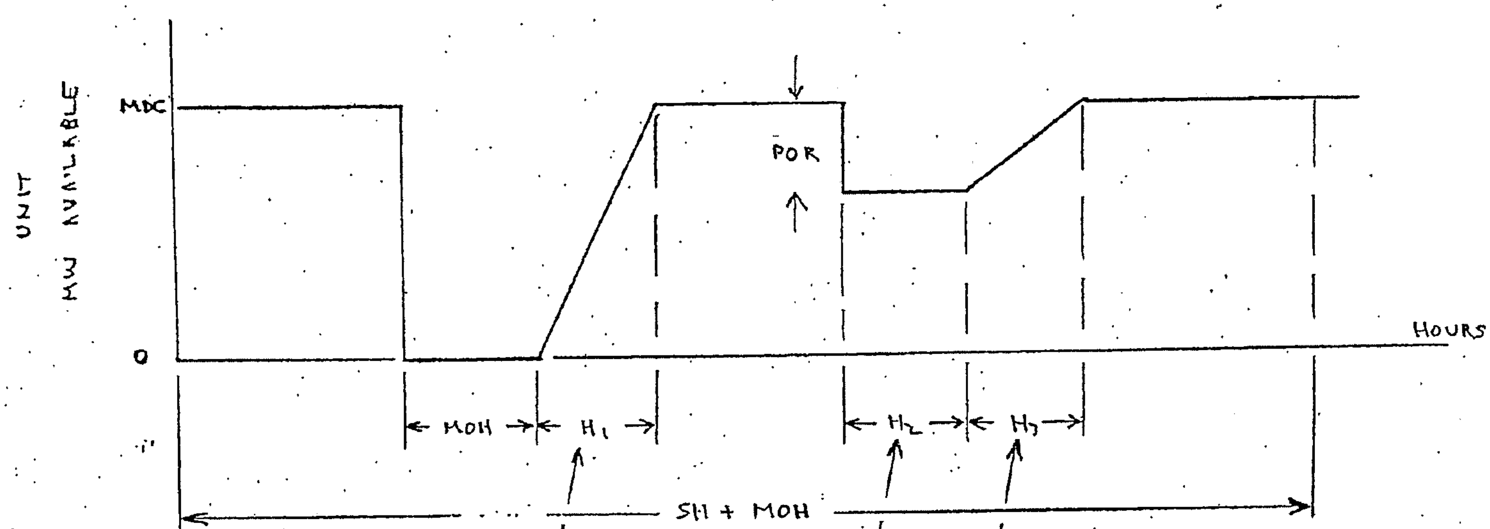


FIGURE 3

EQUIVALENT SCHEDULED OUTAGE HOURS

ILLUSTRATION



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

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

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

$ESOH = ESOH_1 + ESOH_2 + ESOH_3$

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, <u>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</u>.

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

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

[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

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

May 28, 2015

Independent Statistics & Analysis
U.S. Energy Information Administration

Tools Learn About Energy News
Sources & Uses Topics Geography Search eia.gov A-Z Index

Don't forget to reserve your seat at the 2015 EIA Energy Conference June 15-16.

Electric Power Monthly

Data for February 2015 | Release Date: April 27, 2015 | Next Release: May 26, 2015
| full report

Previous Issues
Issue: March 2015 Format: pdf

Table 6.7.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, January 2013-February 2015

	Coal	Natural Gas				Petroleum		
Period		Natural Gas Fired Combined Cycle	Natural Gas Fired Combustion Turbine	Steam Turbine	Internal Combustion Engine	Steam Turbine	Petroleum Liquids Fired Combustion Turbine	Internal Combustion Engine
Annual Factors								
2013	59.7%	48.2%	4.9%	10.6%	6.1%	12.1%	0.8%	2.2%
2014	60.9%	47.8%	4.8%	10.0%	NA	12.8%	1.1%	7.1%
2013								
January	61.2%	46.3%	3.6%	7.3%	4.6%	10.0%	0.7%	2.7%
February	60.6%	46.7%	3.4%	6.7%	4.7%	9.7%	0.4%	2.0%
March	57.7%	44.1%	4.0%	6.8%	5.7%	9.6%	0.3%	1.9%
April	51.3%	40.4%	4.3%	7.3%	6.1%	11.6%	0.6%	2.4%
May	52.9%	41.5%	4.5%	9.5%	5.2%	13.0%	0.7%	2.1%
June	63.4%	50.9%	5.1%	14.7%	6.9%	15.4%	0.8%	1.7%
July	67.9%	58.3%	8.5%	18.6%	8.4%	17.5%	2.1%	2.3%
August	66.3%	60.2%	6.8%	17.6%	8.5%	14.4%	0.9%	2.2%
Sept	61.2%	52.6%	5.6%	14.0%	6.7%	14.1%	1.3%	2.0%
October	54.4%	45.4%	3.9%	8.5%	5.5%	12.7%	0.7%	2.0%
November	56.2%	44.9%	3.9%	7.1%	4.5%	7.3%	0.6%	2.2%
December	63.7%	47.1%	4.6%	8.5%	6.1%	10.2%	0.7%	2.7%

baseload

non-baseload

2014								
January	70.9%	46.9%	6.4%	9.4%	NA	19.4%	3.7%	7.3%
February	71.6%	42.2%	4.2%	8.8%	NA	12.2%	0.8%	6.3%
March	61.4%	39.5%	4.4%	6.9%	NA	13.7%	1.1%	5.8%
April	50.9%	40.3%	3.4%	6.9%	NA	9.5%	0.5%	4.9%
May	53.8%	44.3%	4.8%	9.5%	NA	10.3%	0.7%	9.5%
June	64.5%	50.7%	5.1%	11.4%	NA	15.3%	1.0%	7.3%
July	68.0%	57.0%	5.8%	14.6%	NA	16.1%	1.1%	8.8%
August	67.5%	60.5%	6.1%	16.2%	NA	15.3%	1.5%	8.4%
Sept	59.2%	54.8%	5.2%	12.2%	NA	13.7%	0.8%	8.1%
October	50.8%	48.5%	4.7%	10.3%	NA	9.7%	0.8%	6.5%
November	56.1%	42.8%	4.1%	7.6%	NA	7.5%	0.9%	6.4%
December	56.8%	45.6%	3.3%	5.7%	NA	10.7%	0.5%	5.8%
2015								
January	57.8%	51.1%	3.7%	6.4%	NA	12.3%	0.5%	8.0%
February	65.4%	51.7%	6.1%	8.4%	NA	21.9%	1.6%	6.7%

Values for 2013 and prior years are final. Values for 2014 and 2015 are preliminary. NA = Not Available
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

baseload

non-baseload

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

May 28, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): September 11, 2013

PORTLAND GENERAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Oregon	001-5532-99	93-0256820
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

121 SW Salmon Street, Portland, Oregon 97204
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (503) 464-8000

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure

Portland General Electric Company's (PGE, or the Company) Coyote Springs natural gas-fired plant located in Boardman, Oregon has been out of service since August 24, 2013 due to equipment failures. Coyote Springs has a net capacity of 246 megawatts, which represents approximately 9% of the Company's total net generating capacity.

The Company estimates the repair costs to approximate $2 million. The repairs are expected to be completed and the plant back online by mid-November 2013. At this time, repair costs are expected to be included in operating and maintenance expense. Any potential insurance recovery of the repair costs is subject to a $2.5 million deductible for each event.

As a result of this unplanned outage, the Company expects to incur incremental replacement power costs of approximately $6 million.

PGE will host a conference call with financial analysts and investors on November 1, 2013 at 11:00 a.m. ET to discuss financial results for the third quarter 2013, as well as provide an update on our earnings guidance for the full year, including the impact of the Coyote Springs outage.

Information Regarding Forward Looking Statements

This current report includes forward-looking statements. Portland General Electric Company based these forward-looking statements on its current expectations about future events in light of its knowledge of facts as of the date of this current report and its assumptions about future circumstances. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties and that actual results may differ materially from those projected in the forward-looking statements, which include statements concerning the expected duration of the plant outages, the expected cost of replacement power, the expected cost of repair, and the possibility of insurance recovery. The Company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties included in the Company's most recent Annual Report on Form 10-K and the Company's reports on Forms 10-Q and 8-K filed with the United States Securities and Exchange Commission, including Management's Discussion and Analysis of Financial Condition and Results of Operations and the risks described therein from time to time.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: September 11, 2013

By: /s/ James F. Lobdell
James F. Lobdell
Senior Vice President of Finance,
Chief Financial Officer and Treasurer

CASE: UE 294
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

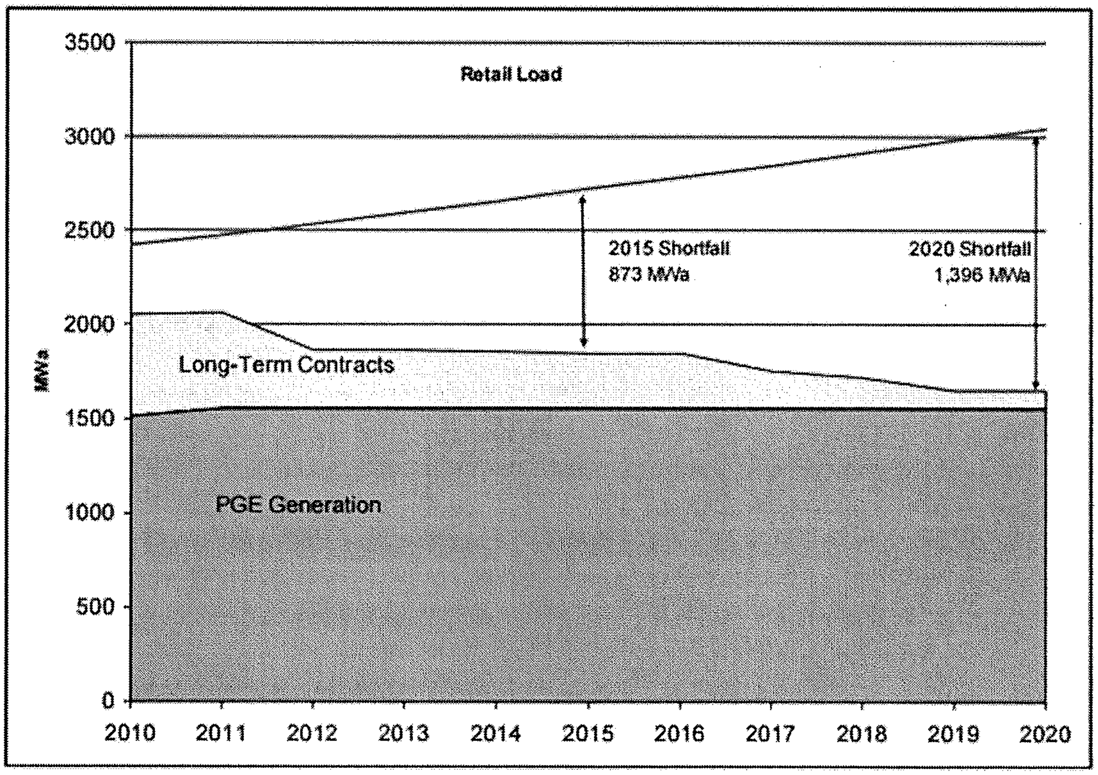
Exhibits in Support
Of Opening Testimony

May 28, 2015

Load resource balance – 2009 to 2015

From PGE 2009 IRP – page 4

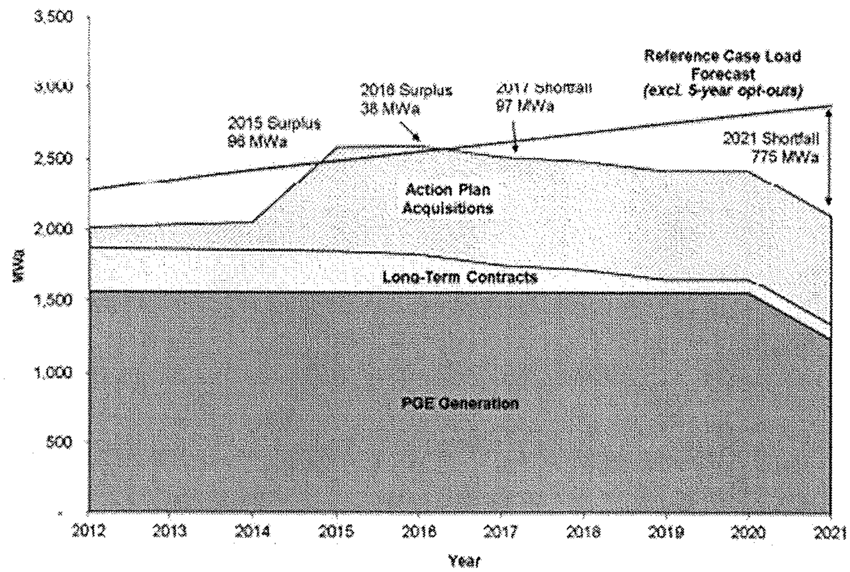
Figure ES-0-1: PGE Energy Load-Resource Balance to 2020



2009 IRP

From the 2011 Update – p 10.

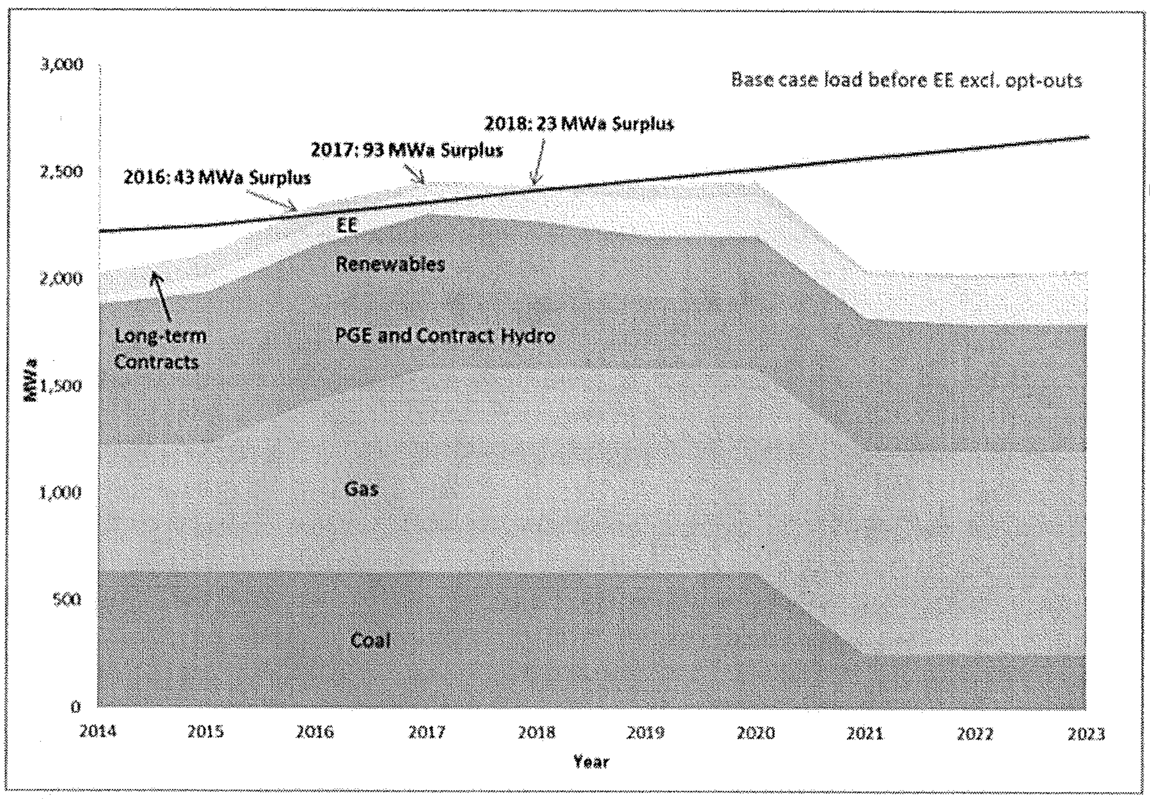
Figure 1-1: Energy Load-Resource Balance to 2021 after Action Plan Acquisitions



2011 IRP

From 2013 IRP p 3

Figure 1: PGE's projected annual average energy load-resource balance



2013 IRP