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A DIVISION OF PACIFICORP

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May 13, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attention: Filing Center

RE: **UM 1355 – Rebuttal Testimony of PacifiCorp**

PacifiCorp (dba Pacific Power) submits for filing an original and five (5) copies of its rebuttal testimony in the above-referenced matter.

PacifiCorp is submitting rebuttal testimony by the following witnesses in this proceeding.

- David J. Godfrey, Director, Asset Management and Compliance
- Mark H. Smith, Director, Generation Planning
- Mark R. Tallman, Vice President, Renewable Resource Acquisition
- Gregory N. Duvall, Director, Long Range Planning and Net Power Costs

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com.

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Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea L. Kelly /JS

Andrea L. Kelly
Vice President, Regulation

Enclosures
Cc: UM 1355 Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the date indicated below by email and/or US mail, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: May 13, 2009.

Carrie Meyer

Carrie Meyer
Coordinator, Administrative Services

Docket No. UM-1355
Exhibit PPL/101
Witness: David J. Godfrey

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of David J. Godfrey

May 2009

Q. Please state your name, business address and position with PacifiCorp (the Company).

A. My name is David J. Godfrey. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah. My position is currently the director, asset management and compliance for PacifiCorp Energy.

Q. Have you testified previously in this proceeding?

A. Yes. I provided direct testimony in April 2009.

Summary of Testimony

Q. Please summarize your testimony.

A. My rebuttal testimony responds to certain issues raised by Commission Staff witness Ms. Kelcey Brown, the Industrial Customers of Northwest Utilities (“ICNU”) witness Mr. Randall J. Falkenberg and the Citizens’ Utility Board (“CUB”) witness Mr. Bob Jenks regarding forced outage rates. My testimony addresses the following issues raised by Staff, ICNU and CUB:

- The exclusion of lengthy outages from the 48-month average,
- The exclusion of imprudent outages and the use of benchmarking to adjust plant performance,
- Adjustments to the 48-month historical average for new capital investments,
- The use of a weekday/weekend split, and
- The data reporting requirements recommended by CUB.

Exclusion of Lengthy Outages from the Historical Average

Q. What is the Company's rebuttal position on the proposed exclusion of lengthy outages from the 48-month average?

A. The Company continues to support retaining all outages in the 48-month average, but will agree that an exception may apply in the most extreme cases of extended duration, with a clarification. The Commission should clarify that the costs of outages excluded based upon duration are generally recoverable through deferred accounting.

Q. Why is the Company's position important from the standpoint of fair cost recovery?

A. PacifiCorp does not have a power cost adjustment mechanism ("PCAM") in Oregon. Therefore, unless an outage is reflected in the forced outage rate, PacifiCorp's only means of recovering the costs associated with the outage is through deferred accounting. Under the Commission's deferred accounting guidelines, a petition must be filed when the cost is incurred and the Commission may require that an outage either cause substantial harm or be unforeseeable before it will allow deferred accounting. See Order No. 05-1070 at 5. If ordinary outages ineligible for deferred accounting are excluded after the fact from the forced outage rate, PacifiCorp will lose any opportunity for cost recovery for these outages.

Q. Can you provide an example?

A. Yes. In UE 191, the Commission excluded from PacifiCorp's forced outage rate the portion of a lengthy outage associated with a manufacturer defect over 28 days. While there was no allegation that the outage was PacifiCorp's fault, the effect of the Commission decision was to preclude recovery for costs incurred during the outage after 28 days. PacifiCorp had no ability to file for deferred accounting for these costs because the Commission decision excluding the outage from the forced outage rate came long after the outage. ICNU claims that removal of such outages "will provide utilities with incentives to achieve good performance," ICNU/100, Falkenberg/10, implying that long outages are also imprudent outages. But the example from UE 191 demonstrates that the two are not synonymous. The removal of lengthy outages appears only to create an incentive for shorter, but more frequent and perhaps more costly, outages.

Q. Is this a material issue for PacifiCorp?

A. Yes. PacifiCorp has an aging generation fleet. With this large and aging fleet comes an increased probability of unexpected and unplanned outage events. In a simplistic example of an automobile, as the car ages there are more parts and systems that approach their end of life. As one part is replaced, that cannot guarantee that another part will not fail in the future. If one plotted the amount of repairs versus time, it would show that the rate of failure is increasing for the car, but not necessarily for a particular part or system. ICNU testifies that lengthy outages may be infrequent, but they have a material cost impact because they result in relatively larger amounts of lost energy. ICNU/100, Falkenberg/11. The Company concurs with this observation.

Q. If the "most extreme cases of extended duration" outages were removed from the 48-month average, how should they be treated?

A. The Company proposes that all the hours associated with that event be removed from the 48-month average and replaced with the same amount and type of hours from the timeframe immediately preceding the event.

Q. Please provide an example.

A. If it was determined that a 58-day outage was an anomalous event that unfairly biases the 48-month average, the Company would remove the forced, equivalent forced, maintenance, equivalent maintenance and equivalent planned derate hours from that 58-day period and replace them with the same categories from the preceding 58 days. In this manner, the 58 days removed are replaced with hours that more closely represent the manner that the plant would have been operating if the event had not occurred. This is a better approximation than just extending the period to include 48 months or replacing the hours with a similar time from historical data.

The Exclusion of Imprudent Outages and Benchmarking

Q. What is the Company's position on the proposed exclusion of individual outages from the forced outage rate for imprudence?

A. While the Company agrees that prudence is a prerequisite to cost recovery, it objects to an overly simplistic application of this principle to the forced outage rate. There are two primary issues of concern. First, the Commission should reject any suggestion for exclusion of particular outages because of individual error, mistake or negligence. The Commission has previously recognized that imprudence requires a higher showing, that of management failure, before an outage may be excluded.

Second, the Commission should review the prudence/management efficacy of a utility's maintenance practices on a system basis, not an individual plant or outage basis.

Q. Why should the Commission review the prudence of a utility's plant maintenance on a system basis, rather than an individual outage basis?

A. For three reasons. First, an individual outage approach is asymmetrical where only subpar performance is adjusted and exemplary performance is not rewarded. Second, the only comprehensive way to evaluate a company's operation is to look at it as a whole and compare it to peer groups. Third, since the imprudence of outages is a function of management failure, not individual mistake, the best way to judge the efficacy of management is to review plant maintenance on a system basis, not a one-off basis.

Q. How should the Commission review the prudence of a utility's maintenance practices on a system basis?

A. With several important caveats, the Company agrees that references to NERC/GADs benchmark data is useful to review the prudence of a Company's maintenance practices. First, it is critical to understand the peer group used for the benchmarking. It is imperative that the right conversion technology is compared, unit size and composition, operating regime and age. All of these factors can skew the results and give false expectation if not fully understood and appropriately corrected.

Second, the Company does not support the use of benchmarking to single out specific units against an industry-wide benchmark to establish future performance. PacifiCorp operates its generation assets as a fleet to maximize the benefit to its customers. To select a single unit is inconsistent with this philosophy.

Third, the Company does not support benchmarking against a single statistic. To fully understand how a company is performing, it is important to view a variety of performance factors, *e.g.*, planned outage hours, capacity factor, etc., since these are all related. For example, a proposal to benchmark only forced outage rates could provide an incentive to a utility to spend more than reasonably necessary on planned outages to lower forced outage rates.

Q. Does the Company support Staff's proposal to benchmark forced outage rates against NERC/GADs forced outage statistics?

A. No, for several reasons. First, the Company does not support the use of benchmarking to establish future performance and cost recovery. While benchmarking is useful to trend fleet performance against a peer group, outside of a more comprehensive, performance-based ratemaking proposal, benchmarking does not supply the specific, cost-of-service data the Commission needs for forecasting rates.

Second, the Staff proposal raises many of the concerns cited above. It is not clear how Staff would form the comparable peer group, the proposal appears to benchmark plants on an individual, rather than fleet, basis, and the proposal focuses only on forced outage rate data, not more comprehensive statistics on plant availability or capacity factor.

Third, compared to the most recent NERC/GADs peer data available (from 2006), PacifiCorp's overall capacity factor was 9 percent higher than industry average. This suggests that benchmarking, if done correctly, would increase the Company's rates above cost-of-service levels, depriving customers of the significant benefits they now enjoy from the Company's above-average plant maintenance and availability.

Adjustments to the 48-Month Average for New Capital Investments

Q. What is the Company's rebuttal position on proposed adjustments to the 48-month average to account for new capital investments?

A. CUB proposes adjusting the 48-month average used for the modeling of future rates by amounts included in the justification of new capital investments, if the investment improves the reliability of the generation facilities. The Company does not support this position. First, it is very difficult to quantify an increase in reliability associated with a particular capital investment. Second, it is not clear how the adjustments would relate to the future actual results. Third, the proposed adjustments are one-sided because a capital investment may result in a decrease in availability.

Q. Can new capital investment also result in lower plant availability?

A. Yes. As noted by ICNU, "there are likely to be situations where new capital investment arguably degrades reliability." ICNU/100, Falkenberg/21. Capital investment related to environmental issues can reduce plant availability. CUB's proposal, if applied fairly and symmetrically, could result in rates reflecting reduced availability more quickly than under the current approach.

Q. Please provide additional support for the Company's position.

A. Capital investments are typically made to improve the reliability or availability of the plant by replacing a worn out or poorly performing part or system. However, at the same time there are other parts and systems that are still wearing out and degrading in their performance. The capital investment addresses one aspect of the plant's reliability or availability, but not all aspects of the plant's reliability or availability.

Q. Please provide an example.

A. Again using the example of an automobile, replacing the tires will decrease the probability of getting a flat. However, it will not reduce the risk of the battery dying. While investing a significant amount of capital to address flat tires, equating that to improving battery life would not be practical. Similarly, with the Company's plants the capital investments help maintain or slow the degradation of performance.

The Use of a Weekday/Weekend Split

Q. What is the Company's rebuttal position on the use of a weekday/weekend split for outage rates?

A. The Company does not support a distinction between weekday and weekend rates when modeling unplanned outage rates.

Q. Why does the Company take this position?

A. There are several reasons the Company takes the position it has on weekday and weekend splits:

1) This is a non-standard NERC/GADS calculation.

2) It takes two rates with different denominators and tries to put them on equal footing.

3) The definition of a maintenance outage is based on the ability of the operator to postpone the event. It does not indicate when it actually starts or ends. Therefore, it is possible to have maintenance outages during the weekday, if this is more advantageous to the operator given market and other conditions, even though it could have been postponed.

4) If the event starts on the weekend, it is not guaranteed to be completed during the weekend and in fact the majority of the hours could fall to the weekday.

5) By using a single unplanned outage rate, it avoids any potential gaming of outage classification by the operator.

Data Reporting Requirement

Q. What is the Company's rebuttal position on the data reporting requirement proposed by CUB?

A. The Company feels that these requirements are overly burdensome for several reasons; 1) this level of detail is not required by the NERC/GADS system, 2) the size of the Company's fleet would necessitate an increase in labor- force to comply with such requests, 3) any specific reports on specific events can be requested during discovery, and 4) this type of reporting is not required in any other jurisdiction where the Company operates.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UM-1355
Exhibit PPL/201
Witness: Mark H. Smith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark H. Smith

May 2009

Q. Please state your name, business address and position with PacifiCorp (the Company).

A. My name is Mark H. Smith. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is currently the Director, Generation Planning.

Q. Have you previously testified in this docket?

A. Yes. I sponsored direct testimony in April 2009.

Q. Will you please summarize your testimony?

A. I rebut the portions of the testimonies of Staff witness Ms. Kelcey Brown and Industrial Customers of Northwest Utilities ("ICNU") witness Mr. Randall J. Falkenberg on hydro outages. To respond to the testimony of Staff and ICNU that modeling of hydro forced outages is unnecessary because such outages do not cause spill, I provide several examples showing the contrary. Because the loss of energy associated with these outages is real and measurable, the Commission should allow utilities to model such forced outages in net power costs. Additionally, I briefly respond to ICNU's testimony that planned outages for hydro should be modeled only in low cost months. The variables the Company must consider in planning hydro outages restrict the Company's ability to schedule outages strictly based on economics. Finally, I respond to ICNU's unfounded allegations concerning the methodology that the Company is developing to model forced outages in hydro.

Q. Please explain why some of the Company's hydro projects that have "storage" capabilities spill water even when the outages do not last very long.

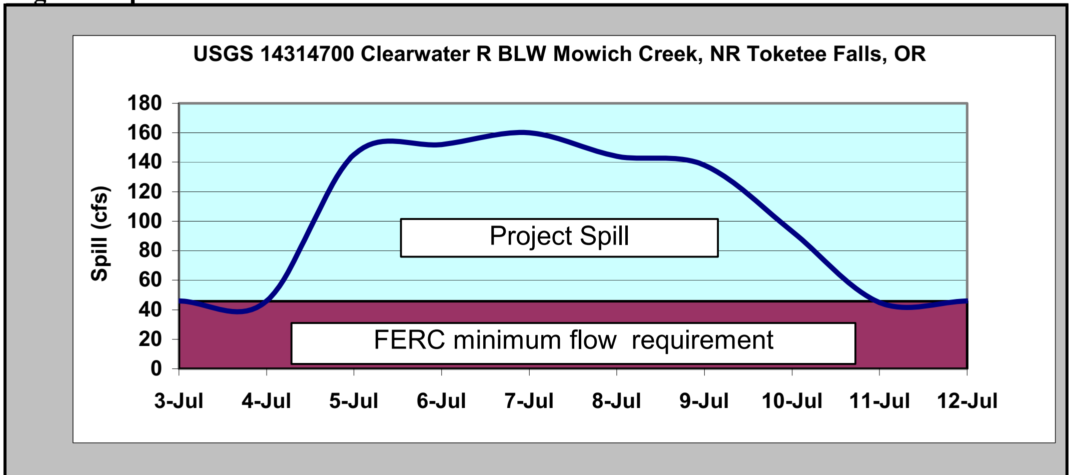
A. The function of the "storage" at those projects is limited to daily shaping, and the Company does not have the flexibility to store water for future use. Even in the case of outages that have been planned ahead of time, there could be spill when the outage is relatively long. The Lewis River system is capable of storing water for a longer time period. However, sometimes the requirements by various regulations will lead to spill.

Q. Can you provide instances of forced outages that have resulted in spill?

A. Yes, see figures 1-3 for illustrations of forced outages that have resulted in spill on "storage" projects. Figures 1 and 2 show two North Umpqua projects, where storage capacity is insufficient to avoid spill in the event of a forced outage.

In Figure 1, the entire period of forced outage caused spill and loss of energy.

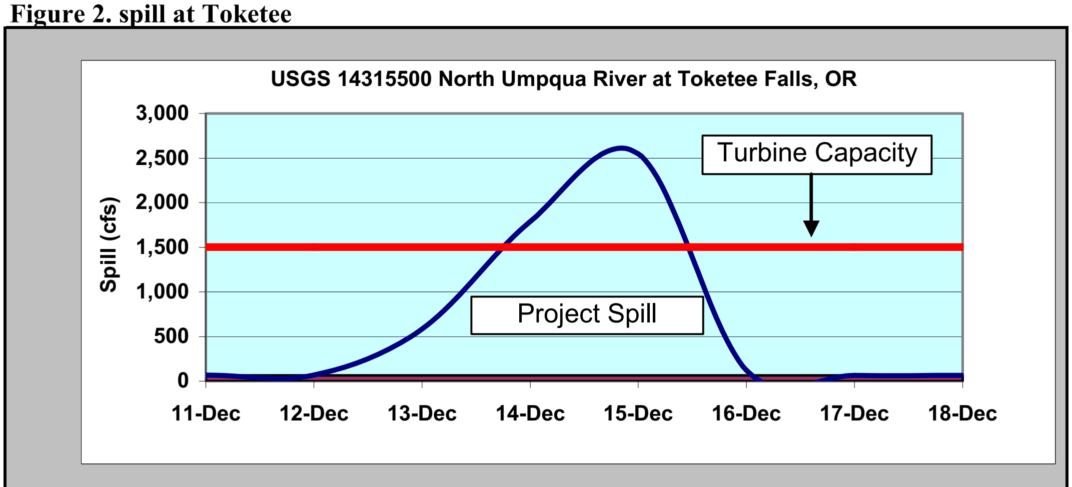
Figure 1. spill at Clearwater No. 2



Clearwater No. 2	Start	End	Duration (hours)	Spill (dsf)	H/K	MWh's lost to Spill
	7/8/06 19:12	7/10/06 9:00	37.8	238	42.5	243

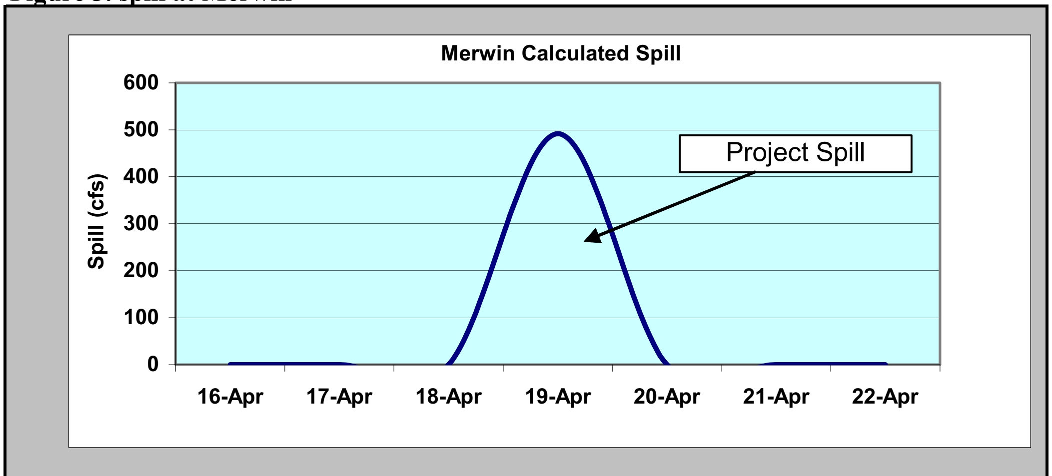
Figure 2 shows that during the period of the spill, only when the amount of spill is below the turbine capacity, there is loss of energy.

Figure 2. spill at Toketee



Toketee	Start	End	Duration (hours)	Spill (dsf)	H/K	MWh's lost to Spill
	12/14/06 20:50	12/15/06 8:55	12.08	3,054	33.5	2,455

Figure 3. spill at Merwin



Merwin	Start	End	Duration (hours)	Spill (dsf)	H/K	MWh's lost to Spill
	4/19/09 6:10	4/19/09 7:40	1.5	492	13	154

In the Merwin example in Figure 3, in the event of a forced outage, spill gates must be opened immediately to maintain flow downstream of the project within FERC ramping limits. More extreme events can occur and spill losses can be more significant during periods of higher project inflows or outflows.

The above examples clearly demonstrate that forced outages at PacifiCorp hydro projects have resulted in spill and lost generation. Such occurrences do lower total generation capability in actual operations and should be modeled.

Q. Can all planned outages occur during periods of lowest cost?

A. No. Due to staffing availability, license requirements or inflow availability, outages cannot always be scheduled during periods of lowest cost. For example, some outages on the North Umpqua are required by the FERC license to occur during periods of higher inflow when energy losses are potentially the greatest.

Q. ICNU alleges that there are "serious problems" with PacifiCorp's approach to modeling hydro outages, which should be solved before such modeling is allowed. Can you respond to this allegation?

A. Yes. First, the Company disputes the allegations that its modeling lacks transparency or that it exaggerates the impact of outages on hydro generation. Second, the Company questions the appropriateness of ICNU importing its litigation positions and discovery on this issue from other states into this generic docket. Third, the decision before the Commission in this case is whether to adopt a policy allowing modeling of hydro forced outages, not to resolve ICNU's litigation positions on the specific design of PacifiCorp's modeling.

Q. What conclusion do you draw from the above discussion?

A. Because of the limited storage capabilities of the Company's hydro projects, outages do cause spill of water that lead to lost energy, even when the outages are planned. The Commission should permit utilities to adopt methodologies to model lost energy due to outages. Also, it is not possible, nor reasonable, to require the Company to schedule hydro maintenance outages entirely based on economics due to various requirements placed on the projects by the operating licenses.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UM-1355
Exhibit PPL/302
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark R. Tallman

May 2009

Q. Please state your name, business address and present position with PacifiCorp (the "Company").

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resource Acquisition.

Q. Are you the same Mark R. Tallman who submitted direct testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to testimony submitted by Oregon Public Utility Commission Staff ("Staff"), the Citizens' Utility Board ("CUB") and the Industrial Customers of Northwest Utilities ("ICNU") with respect to their recommendations on Issue III of the consolidated issues list related to wind availability reporting and forecasting. While Issues IV and V relate to wind plants as well, it appears the parties have embedded their wind-related Issue IV and Issue V comments within their testimony on Issue III; therefore, I do not explicitly discuss Issues IV and V in this testimony.

Testimony Summary

Q. Please summarize your reply testimony with respect to Issue III (i): *What wind availability reporting methodology should the Commission adopt?*

A. The Company's position remains that the most relevant data to report associated with wind-powered generation resources is the historical annual energy production. The Company does not have the capability to produce the "wind availability report" proposed by Staff because the information it seeks is not readily determinable. Similarly, ICNU's recommendation to report data comparable to thermal plants for individual wind turbines would be burdensome, in part because North American Electric Reliability Corporation ("NERC") codes for wind outages do not yet exist.

Q. Please summarize your reply testimony with respect to Issue III (ii): *How should wind availability be appropriately applied to forecasting for a rate determination?*

A. The Company, CUB and ICNU appear to be in general consensus that the energy profile resulting from technical studies should be relied on for the rate setting process; however, consistent with the Commission's decision in Order No. 08-548 (Docket No. UE 200), the Company's position remains that the most recent energy profile for a wind resource should be used when setting rates.

Issue III (i) - What wind availability reporting methodology should the Commission adopt?

Q. What is Staff's proposal with respect to wind availability reporting?

A. Staff proposes an annual "wind availability" report showing (A) the maximum theoretical production of an owned wind facility after subtracting lack of availability due to: (B) planned maintenance; (C) line loss; and (D) forced outages, turbine failure or non-scheduled maintenance. In Staff's proposed report, factors "B", "C" and "D" are subtracted from "A" to provide (E) the actual capacity factor for the wind facility in a calendar year.

Q. Is it feasible for the Company to provide this information for a wind availability report?

A. No. The Company is unable to implement Staff's formula of E = A – B – C – D. As I explained in my direct testimony, the output of a wind facility is influenced by multiple and interdependent variables. Wind resources are similar to run-of-river hydro resources in that the fuel source is intermittent. Therefore, the Company has no valid way to determine the amount of energy a wind project might have produced ("A") but for planned maintenance, but for line loss and but for forced outage, turbine failure or non-scheduled maintenance. Because such variables are not independent, and absent expensive technical studies on an annual basis, the Company is not able to derive "A" by translating "B", "C" and "D" into theoretically lost energy amounts. The Company does have "E" (actual output). The Company proposed in my direct testimony to report "E" to the Commission via the Company's annual Federal Energy Regulatory Commission ("FERC") Form 1 report or the Results of Operations report.

Q. Is there an industry standard methodology for performing the calculations required to produce Staff's proposed wind availability report?

A. No.

Q. Does Staff provide an example of how to perform the calculations required to produce its proposed wind availability report?

A. No.

Q. The Company has power purchase agreements ("PPAs" or a "PPA") with third parties that include a provision intended to liquidate energy lost due to certain curtailment events. Is this evidence that the Company can compute Staff's formula of E = A – B – C - D?

A. No. The language in such PPAs is intended to liquidate damage to the seller as a result of the Company calling for curtailment under certain situations. Such curtailments are likely to happen infrequently and for short periods of time (i.e., for a finite number of hours and, typically, for an hour or less). Because there is no established formula for calculating such lost energy while also taking into account all the variables impacting overall production, these PPAs incorporate general intent and remand the lost energy assessment to the seller for subsequent audit by the Company. The result of the damage settlement process will likely be negotiated settlements as the seller has an inherent bias to estimate on the high side and because of the difficulties in making a statistically valid estimate. To date, the Company has not invoked a curtailment pursuant to a wind resource PPA.

Q. What is the significance of the Company's inability to routinely calculate factors "B", "C" and "D" on a stand alone and discrete basis?

A. As described in my direct testimony, detailed after-the-fact technical studies must be performed by expert consultants to estimate factors such as "B", "C" and "D". Many of these variables cannot be directly monitored and, as a result, there is no direct cause and causation link that can readily be established between resource performance and a single variable. This means that one variable (e.g., overall availability or availability for individual turbines) cannot simply be looked at in isolation and a statistically valid conclusion drawn as to why forecasted energy production for the entire resource varied from actual energy production due solely to that variable. As such, entities that perform such studies rely on computer models to help forecast energy production.

Q. Will the Company's reporting recommendation result in the type of information Staff seeks?

A. Yes. The Company's recommendation to commission new technical studies on a periodic basis and using actual data is intended to supply the type of information Staff appears to seek (e.g., are annual variances from the previous technical study due to meteorological issues, operational issues or a combination). The Company's recommendation is to order a new technical study every five years or when it is evident that such a new study should be performed (i.e., earlier or later than five years). This approach is consistent with Staff's view that the historical performance of the generating unit is the best predictor of what will occur in the future. (Staff/100, Brown/2, lines 7-9)

Q. What is ICNU's proposal with respect to wind availability reporting?

A. ICNU testifies that the Company should prepare wind availability reports for the Commission based on NERC outage codes for thermal plants; however, NERC outage codes for wind plants do not currently exist.

Q. What is the current status at NERC of establishing codes applicable to wind resources?

A. NERC is in the final stages of establishing the reporting requirements and the associated codes applicable to wind-powered generation resources. The timing for the finalization of this process is not currently known.

Q. How does the Company respond to ICNU's reporting recommendation?

A. It is burdensome to ask the Company to create reports when NERC has not yet fully developed its requirements with respect to wind-powered generation resources. Once NERC codes applicable to wind resources are fully developed and finalized, the Company will begin collecting that data.[1] Until such time as finalized NERC codes are available, the Company believes that the most relevant data to report associated with wind resources is the historical annual energy production. The Company currently reports this information via its annual FERC Form 1. The Company could also make this information available in its annual Results of Operations report filed with the Commission each year.

Q. Will the availability of NERC codes for wind resources enable the Company to produce the annual "wind availability report" sought by Staff?

A. No. Because of the interdependent nature of variables that can impact productions levels, NERC codes will not likely enable the Company to perform the calculations sought by Staff. However, the NERC codes will be of use to consultants who perform updated technical studies on a periodic basis. This further supports the Company's position that technical studies should be updated on a periodic basis by experts with the appropriate tools (e.g., the appropriate computer programs) and with an adequate amount of actual data to re-establish the energy profile for a wind resource. The re-established energy profile would

[1] Subject to availability of data via the supervisory control and data acquisition system. Fiber failures (e.g., due to rodent damage) or other reasons can result in data acquisition gaps.

then become the most recent reliable data used for setting rates during subsequent test periods.

Issue III (i) - How should wind availability be appropriately applied to forecasting for a rate determination?

Q. What are ICNU's and CUB's positions with respect to Issue III (i)?

A. ICNU proposes that utilities be required to use, for a "sufficiently long period of time," the same wind output assumptions for power cost models as were used in the resource acquisition process. Similarly, CUB proposes that the performance forecast (i.e., capacity factor) that was used in the competitive bidding process be used during the first five years of a wind resource.

Q. Are these positions similar to the Company's proposal?

A. Yes, the positions are similar; however there is one key difference. In the Company's recent Renewable Adjustment Clause ("RAC") proceeding, the Commission stated that the "[t]he most recent reliable data should be used to set rates for the test period". Docket No. UE 200, Order No. 08-548, p. 21. In some instances, as in the RAC proceeding, there may be updated consultant reports that are a more appropriate basis to forecast wind energy production. Consistent with the Commission's decision in the RAC, the Company continues to recommend that the most updated, reliable information should be used in setting rates.

Q. CUB raised a concern that utilities can alter the outcome of a competitive bidding process by inflating wind capacity factors and therefore proposes to link the capacity factor estimate to the request for proposal ("RFP") process. How does the Company respond to CUB's concern?

A. The concern raised by CUB regarding bias is not an issue related solely to utility owned resources. Any entity who submits a false profile during the RFP process has the potential of altering the RFP outcome; regardless of structure (ownership or PPA). The Commission should address this issue on a case-by-case basis if and when evidence is presented that an entity has put forth a false profile. The Commission's approach to setting rates for new wind resources should not be based upon the unproven assumption that a RFP participant might submit false profiles for the purpose of altering an RFP's outcome.

Q. For clarification, please describe what the most recent reliable data would be for forecasting wind-powered generation resources owned by another party?

A. Since the Company is unlikely to have access to the most recent energy production study for resources owned by another party, the most recently reliable data would be historical actual metered energy production or periodic estimates provided by the Company's contractual counterparty.

Q. Does this complete your rebuttal testimony?

A. Yes.

Docket No. UM-1355
Exhibit PPL/400
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Gregory N. Duvall

May 2009

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power ("Company").

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon, was responsible for directing the analytical effort for the Multi-State Process ("MSP"), and currently direct the work of the integrated resource planning group, the load forecasting group, and the net power cost group in the Company.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the Company's rebuttal position on the modeling of thermal outage rates in GRID, which is the Company's production cost model used in the ratemaking process. The Company's direct testimony of Mr. David J. Godfrey presented the Company's approach to forecasting plant availability for planning and scheduling and recommended use of the NERC/GADs Equivalent Unplanned Outage Factor ("EOUF") for all baseload plants and the NERC/GADs Equivalent Unplanned Outage Rate ("EUOR") for flexible plants. While this formula is appropriate for forecasting, my rebuttal testimony clarifies that the Company needs a rate, not a factor, for purposes of modeling net power costs in GRID. For purposes of modeling net power costs, the Company agrees with the position of most of the other parties to this docket to retain the Commission's current approach, Equivalent Outage Rate ("EOR"), except with respect to gas peaking plants.

In addition, I rebut certain portions of the testimony of the Industrial Customers of the Northwest ("ICNU") witness Mr. Randall J. Falkenberg and draw the following conclusions:

- ICNU's proposed methodology for determining planned outage schedules is arbitrary, creates impractical maintenance schedules, and has many details that would need to be worked out before it could be considered a methodology. It should be rejected. In addition, I present the Company's method which is logical and understandable and should be adopted by the Commission.
- ICNU's proposal to arbitrarily alter the physical characteristics of thermal plants is not reasonable or realistic, is one-sided and should be rejected by the Commission.
- ICNU argues that PacifiCorp's ramping adjustment should not be included in the forced outage rate. The Company is willing to unbundle the ramping adjustment from the forced outage rate and treat it as a separate adjustment to

GRID. ICNU's argument that the Company has not supported its ramping adjustment is unfounded.

Thermal Outage Rate in GRID

Q. What is the Company's position on modeling thermal outage rates in GRID?

A. The Company continues to support using the NERC/GADs standards EUOF and EUOR for forecasting plant availability, as explained in the direct testimony of Mr. Godfrey. However, these formulas do not apply to modeling plant availability in GRID for the purpose of setting rates. For this purpose, the Company agrees with Portland General Electric ("PGE"), Citizen's Utility Board ("CUB") and ICNU that there should be no change from the current calculation for forced outage rates for all plants, EOR. The exception is for gas peaking plants, which the Company addresses separately below.

Q. Why is the Company proposing a different approach for forecasting and rate modeling?

A. Forecasting plant availability and modeling plant availability in rates are two different exercises. The Company's direct testimony focused only on the appropriate formula for forecasting. In reviewing the direct testimonies of the other parties, most of which addressed modeling plant availability in rates, the Company realized that it had addressed the overall question in Issue I ("What forecasting methodology should the Commission adopt for thermal generating plants?), but failed to clearly address the modeling sub-issue I(D) ("What is the appropriate methodology for calculating forced outage rates and how should that be applied within the power cost model?").

Q. Why can't the Company use the same formula for forecasting plant availability and modeling plant availability in rates?

A. First, for forecasting thermal plant availability, the Company proposed use of a factor, EUOF, which works well for forecasting but cannot be used directly for setting rates. The difference between a factor and a rate is in the denominator: the denominator in a factor is all period hours, which is appropriate when forecasting overall availability. In contrast, the dominator in an outage rate is all hours when the unit is available for dispatch in the period, which include service hours, maintenance outage hours and forced outage hours.

Second, while the Company proposed use of a rate formula, EUOR (a NERC/GADs standard term), for forecasting the availability of flexible resources, EUOR is inferior to the Commission's current formula for modeling outage rates, EOR, because EUOR omits Equivalent Planned Dispatch Hours ("EPDH") while EOR includes EPDH. To use EUOR, the Commission would have to add EPDH to the formula, which is the same as EOR.

Q. What is the Company's current EOR calculation?

A. The Company uses the following calculation for EOR:

Equivalent Outage Rate ("EOR") = Equivalent Unplanned Outage Rate ("EUOR") with the Equivalent Planned Derate Hours ("EPDH") added to the numerator.

The terms EUOR and EPDH are defined in the direct testimony of Mr. Godfrey and are NERC/GADs terms. The term EOR is not an official NERC/GADs term, but is a composite term specified in the 1984 Oregon Staff memo which is provided as Staff/102, Brown/5, using the formula for EOR at the top of the page[1].

Q. Why does the Company support continued use of the Commission's EOR formula for setting outage rates?

A. EOR meets the primary goal in modeling outages, which is to capture all of the outages and derates associated with the thermal fleet and model them in a manner that results in the proper amount of unavailable generation. As shown in Exhibit PPL/401, unavailability is divided into two main categories; outages and derates. Within these categories, there is additional granularity for planned, maintenance and unplanned (forced) events, for a total of six categories.

All three derates along with forced and maintenance outages are included in the EOR. Planned outages are the only type of unavailability that is not included in the EOR but modeled separately.

Q. All parties other than Staff support continuation of EOR. Can you comment on the Staff approach?

A. Yes. Staff has proposed an availability factor, similar to the Company's EUOF. While Staff's factor formula could be used for forecasting plant availability for scheduling and planning, as explained above, the Company cannot use a factor directly for setting rates in GRID. Putting aside the issue of modeling maintenance outages differently from forced outages (which is addressed in Mr.

[1] For PacifiCorp, the terms Synchronous Hours, Pumping Hours, EFDHRS, and EMDHRS in the equation on line 5, PPL/100, Godfrey/5 are all zero. Thus the equation for EUOR simplifies as follows:

$$EUOR = \frac{FOH + EFOH + MOH + EMDH}{FOH + MOH + SH}$$

The term ESOH from the 1984 staff memo includes both EMDH and EPDH, thus making it the same as the Company's formula for EOR.

Godfrey's rebuttal testimony and could be addressed through a separate adjustment to EOR, if appropriate), EOR otherwise appears to be a reasonable means of converting Staff's equivalent availability factor into a rate formula useful in setting net power costs.

Q. What type of plant should the EOR described above be applied to?

A. The EOR should be applied to all thermal plants except peaker plants.

Q. What is the Company's rebuttal position for peaker plants?

A. After reviewing the direct testimony of other parties, the Company supports using the EFOR(d) on peaker plants, after allowing the Company a reasonable period (12 months) to gather the data necessary to implement this approach.

Q. What should the Commission consider to be the definition of peaker plant?

A. A peaker plant should be defined as a simple cycle combustion turbine, consistent with the Revised Protocol that has been adopted by the Commission for inter-jurisdictional allocation of the Company's revenue requirement.

Q. What is the difference between the EOR and the EFOR(d)?

A. They are the same, except the EFOR(d) excludes Maintenance Outages from the outage rate. This is acceptable to the Company for its peaker plants, Gadsby units 4, 5 and 6 only. Exclusion of Maintenance Outages from the outage rate for combined cycle plants or coal plants is not reasonable because of the relatively high load factor of these plants. This makes it impossible to perform Maintenance Outages when the plant would have otherwise not been economic to run.

New Resources

Q. What is the Company's position on forecasting availability for new resources for which there is no historical data?

A. The Company re-iterates its proposal to use the manufacturer's or project guarantee for the first year. Then as actual operating data is collected, it would be used to calculate the four-year historical average, using a weighted average. The Company proposes that the first year of actual data not be used, as it is skewed by normal start-up issues. By eliminating this data from the historical average, it reflects a more realistic operating profile for the resource.

Q. How does this differ from other parties in this case?

A. The key disagreement appears to be with Staff, which proposes to use industry or NERC/GADS average data for the years where four years of data is not available. CUB also suggests the use of industry data, combined with additional, plant-specific data.

Q. Why does the Company disagree with this approach?

A. The use of industry or NERC/GADS average data does not account for specific design and operating constraints that are present in a given project.

Planned Outage Schedule

Q. What is the generic policy question before the Commission on planned outages?

A. The question, as defined by the issue list, is what methodology the Commission should adopt for modeling planned maintenance (e.g., average vs. forecast).

Q. Does PacifiCorp agree with Staff, ICNU and CUB that it should continue to use a 48-month average to model planned outages?

A. Yes.

Q. Does ICNU go on to present a very detailed, PacifiCorp-specific approach for modeling planned outages?

A. Yes. ICNU proposes an out-of-model financial adjustment based on the results of four GRID studies, none of which are the normalized study used for setting rates. Specifically, ICNU calculates the financial adjustment by taking the difference between the average net power cost from these four alternative studies and the base net power cost study. ICNU's proposal would require each GRID study presented by the Company or any party to be accompanied by four additional GRID studies. The average net power costs of these four additional GRID studies overrides the results of the base power cost study.

Q. Is ICNU's proposal outside the scope of this docket?

A. Yes. ICNU's proposal goes beyond generic policy setting into a detailed, Company-specific implementation proposal. Given the nature and schedule of this generic policy docket, it is difficult for PacifiCorp to adequately respond to ICNU's many unfounded litigation contentions and accusations. The Commission should either reject ICNU's planned outage proposal as unreasonable on its face or defer the issue to PacifiCorp's pending Transition Adjustment Mechanism ("TAM"), UE 207, or general rate case, UE 210.

Q. ICNU self-proclaims the use of an out-of-model financial adjustment using four additional GRID studies to be the "gold standard." Do you agree?

A. Absolutely not. This is a sharp departure from any method the Company has ever used. I am not aware of any utility or commission that uses ICNU's proposed method. It is cumbersome and unnecessary, and certainly can not be held up as adding any value over any other method. Use of a normalized, single maintenance schedule in the base power cost study is far superior to ICNU's multi-GRID run proposal.

Q. Please describe the composite outage schedule proposed by ICNU.

A. Based on the information presented by ICNU, the composite outage schedule proposed by ICNU is called the "centering" option, which places one-fourth of each historic outage for each unit in the center about the mid-point of the historic outage time. Each outage is rounded to a whole number of days.

Q. What is the result of this method?

A. As shown in Exhibit PPL/402, this centering method produces a chaotic outage schedule with a number of problems. For example, in the spring, there are times with no outages and other times with over 3,000 megawatts on planned outage at the same time. In addition, this schedule removes from service all four units at Jim Bridger at the same time. The schedule also shows fragmented outages for the same unit during the year, and shows the same unit having more than one outage at the same time. When this latter circumstance occurred, the outage schedule would have less total megawatt-hours of outages than the four-year average. The Company believes that fixing these serious flaws in the "centering" method would involve a significant number of subjective judgments. For all of these reasons, the Commission should not adopt ICNU's "centering" proposal.

Q. How does the Company schedule the normalized planned outages?

A. In GRID, the length of the planned outages is based on 48-month historical data, and the planned outages are scheduled in a way that all plants are on maintenance during the test year, even though this is not the actual practice. The outages are scheduled on a control area basis, and within certain windows to take advantage of the market conditions and limit the number of major units on planned outage at one time. Due to the length of the outages, however, it may be necessary for several plants to be on outage simultaneously.

Q. Why doesn't the Company use the historical schedule of the planned outages in its normalized net power cost calculations when it uses historical length of the planned outages?

A. The Company plans for major overhaul of units in a four-year cycle in general. For major overhauls, the outage time is longer. The major overhauls of various units are scheduled at different times and in different years to minimize any significant impact to generation levels and reliability of the system. In addition, the timing of the historical planned outages is impacted by the composition of the resources at the time, market conditions at the time and load at the time. Because of the need to normalize the costs of this four-year cycle into a single test year, the actual historical schedule cannot be used in ratemaking without some modification.

Q. What process does the Company use to place the various units into the model in scheduling outage times?

A. ICNU alleges that the Company's methodology for developing its planned outage schedule is arbitrary and subjective. This is untrue. The Company uses a tree-modeling approach which systemically spreads the planned units for maintenance over defined periods of time, as shown in Exhibit PPL/403. Using history as a guide, the Company understands that spring and fall timeframes are the cheapest periods of time to have plants down. Based on the tree structure, the maintenance of most of the units are sequenced and scheduled in the spring. For normalized rate making purposes, planned outages are scheduled so that all units are on maintenance during the test year, and the timing of the outages are scheduled not to fall within certain periods during the year due to the obligations to serve both the retail load and wholesale contracts. For example, the schedule takes into consideration the need to avoid planned outages in the winter.

With this requirement, it is necessary for several units to be on maintenance outage simultaneously. However, the number of major units on maintenance is not to exceed three on a control area basis. As the result, not all of the plants can be maintained in the spring when the market prices are generally lower. In addition, the units are sequenced to approximate the effect of fully utilizing the same crew by location.

Q. Do you assume the same fixed maintenance schedule in all normalized NPC calculations?

A. No. The schedule of each unit may move a little depending on the length of the normalized planned outages that precede it. However, the structure of the tree will remain the same from one proceeding to another. If the Commission decides to address the implementation of the four-year planned outage average for PacifiCorp in this case, the Company recommends that the Commission find that the Company's tree-based approach is reasonable for developing normalized outage schedules.

Q. ICNU makes a recommendation to move the planned outage for Currant Creek from Fall to Spring. Is this reasonable?

A. No. First, this seems like a PacifiCorp specific issue that is not appropriately addressed in this generic outage docket. Second, ICNU does not present a solid basis for their recommendation. Finally, Currant Creek is a newer plant and does not have long enough a history to suggest a preferred time for the performance-based maintenance. The Company recommends the Commission reject this proposal from ICNU and wait until sufficient history is available to make a more informed decision on the placement of the outages of Currant Creek and PacifiCorp's other combined cycle combustion turbine plants.

Heat Rate and Minimum Load Deration

Q. Like ICNU's litigation proposal for PacifiCorp's planned outage schedule, is the Heat Rate/Minimum Deration issue also a PacifiCorp-specific litigation proposal and therefore outside the scope of this generic policy docket?

A. Yes.

Q. Please describe the application of the deration method by the Company and ICNU's proposed adjustment to heat rates and minimum plant generation levels.

A. The Company's approach derates the maximum capacity of the unit in every hour of the year by an equal percent based on historic forced outage rates, which constitutes a "hair cut" in unit availability. The alternative approach sponsored by ICNU would make adjustments in both the minimum capacity and heat rate of the unit, in addition to maximum capacity adjustment made by the Company. ICNU's approach alters thermal plant heat rate curves to artificially increase their efficiency as compared to the heat rate curves that are developed from actual plant operating data. In addition, ICNU proposes to reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching. Since the Company does not make these two adjustments, ICNU claims that "PacifiCorp's method is simply wrong and can produce absurd results". The Company has never made ICNU's proposed adjustments before, nor has ICNU proposed these two adjustments in Oregon prior to 2008 in UE 199.

Q. Are ICNU's heat rate and minimum generation adjustments reasonable?

A. No. The Company strongly objects to these adjustments and will show that they are one-sided and cause net power costs to be artificially understated.

Q. Please comment on the hypothetical example presented by ICNU on this issue.

A. The hypothetical example provided by ICNU is irrelevant and misleading. In essence, it compares the results of the hypothetical example under two cases; one with the minimum derated by 50 percent and the other without any deration to the minimum generation level. Since the answers do not match, ICNU concludes that the Company's approach of not derating the minimum generation level produces the wrong answer.

Q. ICNU suggests that unless the minimum generation level of thermal plants is derated, then the derated maximum generation could be below the minimum generation. Is this a possibility?

A. No. The Currant Creek example assumes monthly outage rates, which are not used by the Company. This example, as well as the hypothetical example, represents a situation that would never occur on the Company's system (i.e. a unit with an annual outage rate of 50 percent). No thermal unit in the Company's fleet has an annual outage rate greater than 16 percent and no plant has a spread between the minimum generation level and the derated maximum of less than 14 percent. There is no mathematical possibility that could result in the derated maximum generation being below the minimum generation. Much of ICNU's argument on these issues is based on this erroneous assumption.

Q. Should the use of the derating method for modeling forced outages change the heat rate or minimum generation level of a unit?

A. No. In fact, changing the heat rate curve or the minimum generation level can lead to unintended consequences. For example, if a unit is dispatched at a level below the derated capacity, the heat rate will be wrong if it has been changed, since the heat rate at that level is unrelated to the derating. The same type of unintended consequences can occur when derating the minimum generation level.

In that case, the model could dispatch the unit at a level it is not capable of achieving.

Q. Why does ICNU's proposed method significantly understate the heat rates?

A. It is because the derate adjustments are applied incorrectly. The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at its derated maximum capacity, with the assumption that the unit may be dispatched at its stated maximum capacity in GRID if there were not the availability "hair cut." When the unit is dispatched at a level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs. Exhibit PPL/404 shows the heat rate curves under the two methods for a coal-fired unit and gas-fired unit, from minimum to maximum generation level. The exhibit clearly demonstrates that heat input required for various levels of generation is understated using the derate-adjusted heat rate. Superimposed on the heat rate curves is the distribution of hourly generation as produce by GRID using the Company's study that was filed in UE 207. In both cases, there are many hours of dispatch below the derated maximum capacity, which are the generating levels at which ICNU's proposal will understate the heat rate, and subsequently understate net power costs.

Q. Does this suggest that the Company should adjust the heat rates at least to the derated maximum capacities of the units?

A. No. The Company uses the "hair cut" to adjust down a unit's capacity that is still at a relatively efficient level. In actual operations, a unit can be derated to any level between its minimum and maximum capacities.

Q. Does it logically follow that the minimum generation level should be derated because the maximum generating level is derated?

A. No. There is no logic that ties the two together. The purpose of the "haircut" to the maximum generating capability is to exclude the unit from producing generation when it is broken. That is fully accomplished through the "haircut" to the maximum generating capacity.

Q. Is it realistic to derate the minimum generation level of a unit for forced outages?

A. No. The minimum generation level of a unit is based on its technical specification below which it cannot operate. Reducing the minimum generation level of units below their technical capability artificially increases the operating range of each unit thereby incorrectly reducing net power costs. Since PacifiCorp has over 30 thermal units, this can amount to a significant reduction to net power costs that the Company is simply not capable of achieving.

Q. ICNU has compared actual heat rates to modeled heat rates. Is this a useful comparison?

A. It is not an unreasonable comparison for coal plants that run at very high capacity factors. For plants that are flexible and can and do operate at various operating levels and heat rates, the comparison becomes relatively meaningless. The "normal" conditions where the units operate in can be quite different from the actual conditions. Actual conditions can bring hydro, loads and market behavior that is significantly different than "normal." The Commission should heavily discount this comparison of modeled heat rates to actual heat rates.

Ramping Adjustment

Q. What is ICNU's recommendation with regard to the Company's ramping adjustment?

A. ICNU argues that the Company's ramping adjustment should not be included in the outage rate. While the Company includes the ramping adjustment in the outage rate as a matter of modeling convenience and would not object to separating it from the outage rate for input into GRID.

Q. Does ICNU recommend that the ramping adjustment be rejected by the Commission?

A. No. For purposes of this docket, I believe the only recommendation from ICNU on this issue is to separate it from the outage rate. To the extent that ICNU opposes PacifiCorp's ramping adjustment on the merits, this would again appear to be a non-generic issue outside the scope of this docket.

Q. What is the purpose of the ramping loss adjustment the Company modeled in its normalized NPC?

A. The ramping loss adjustment is designed to capture the impact of the generation from a thermal coal-fired unit as modeled in GRID but not available in actual operation when the unit is starting up after being offline.

Q. What is involved in starting up a thermal unit?

A. As stated in Steam, by Babcock & Wilcox[2],

[2] The Babcock & Wilcox Company. Steam. 40th ed. 1992, p. 43-4.

> "Operating procedures vary with boiler design. However, certain objectives should be included in the operating procedures of every boiler: 1) protection of pressure parts against corrosion, overheating, and thermal stresses, 2) prevention of furnace explosions, and 3) production of steam at the desired temperature, pressure, and purity."

The actual time required for each unit to startup is largely dependant on the design of the unit and the temperature of the components. On average for steam generating units, this period of time takes about eight hours if the unit can quickly be brought back online while still hot, or over 24 hours if the units have been allowed to cool.

There are four events of note when discussing startup:

1) Clearance Release – The cause of the outage has been addressed, and the unit is cleared for operations to begin warming the unit.
2) Synchronization to Electric Grid – Steam is flowing to the turbine which is spinning the generator at 3,600 rpm. At this time, the outage is complete for tracking purposes.
3) Unit Available for Dispatch – The unit load has increased to a point where generation can be dispatched based on customer demand.
4) Unit at Full Load – The unit load has increased to the maximum rated capacity.

Q. Does the GRID model consider these procedures and events?

A. No. In GRID, all thermal units are modeled as if they can start up and be available at their full capabilities instantaneously when returning from offline. As a result, the energy output from the generating units is overstated for the duration when the units are starting up. Figure 1 depicts the difference in generation between what is modeled by GRID and what occurs in actual operation.

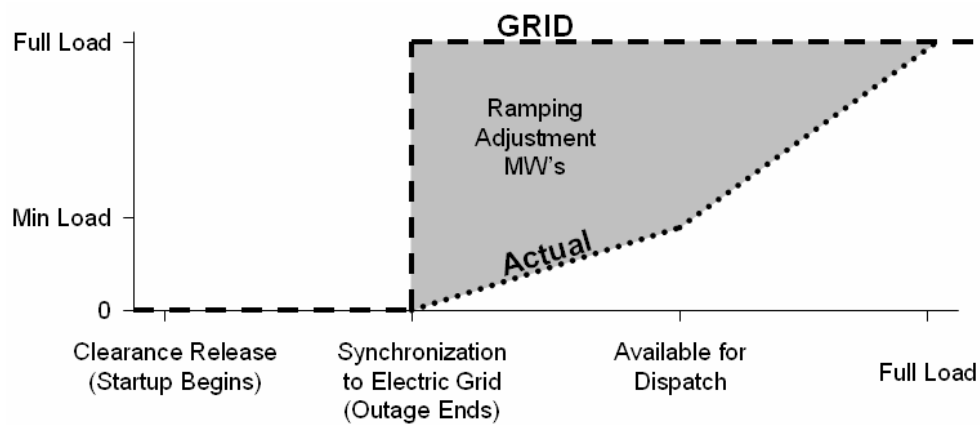


Figure 1. GRID vs. Actual Unit Ramping

Q. How does the Company estimate the ramping loss adjustments for the coal-fired units?

A. The ramping losses are calculated, based on actual 48-month historical hourly data, as the difference between a thermal unit's availability and actual generation within a conservatively assumed maximum of a twelve-hour window after the unit returns from being offline for any reason. The estimates are also limited to only include the differences that are greater than ten percent of the availability. If the differences fall within ten percent of the availability in less than twelve hours, any differences after that time are also excluded from the estimates. That is, it is assumed that there are no ramping losses after twelve hours even if the unit still has not reached its availability, and it is also assumed that there are no ramping losses if the difference between unit's availability and generation is less than ten percent of the unit's availability.

Q. Does the Company model ramping loss adjustment for the gas-fired units?

A. No. Although the gas-fired units may not be available instantaneously after returning from any offline period, the time for them to start up is much shorter. For an hourly model like GRID, the difference is not as significant. The Company's Gadsby units 1, 2 and 3 are steam generating units by design, although they are gas-fired. However, for simplicity, they are treated the same as other gas-fired units and do not have ramping loss adjustments.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. UM-1355
Exhibit PPL/401
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

North American Electric Reliability Corporation/Generating Availability Data System (NERC/GADS) Classifications for Unavailability

May 2009

North American Electric Reliability Corporation/Generating Availability Data System (NERC/GADS) Classifications for Unavailability

NERC/GADS has two main categories of unavailability; outages and de-ratings. Within these categories, there is additional granularity for planned, maintenance and unplanned (forced) events.

A Outages

An outage exists whenever a unit is not synchronized to the grid system and not in a Reserve Shutdown state. An outage starts when the unit is either desynchronized from the grid or when it moves from one unit state to another (for example, goes from a Reserve Shutdown to a Maintenance Outage.) The outage ends when the unit is synchronized to the grid or moves to another unit state[1].

i Planned

An outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks, and occurs only once or twice a year. Turbine and boiler overhauls or inspections, testing, and nuclear refueling are typical Planned Outages.

ii Maintenance

An outage that can be deferred beyond the end of the next weekend (Sunday at 2400 hours), but requires that the unit be removed from service, another outage state, or Reserve Shutdown state before the next Planned Outage. Characteristically, a Maintenance Outage can occur any time during the year, has a flexible start date, may or may not have a predetermined duration, and is usually much shorter than a Planned Outage.

iii Forced

An outage that requires immediate removal of a unit from service, another Outage State, or a Reserve Shutdown state. This type of outage usually results from immediate mechanical, electrical or hydraulic control systems trips and operator-initiated trips in response to unit alarms.

1 Generating Availability Data System, DATA REPORTING INSTRUCTIONS, page III-7.

B De-ratings

A de-rating exists whenever a unit is limited to some power level less than the unit's Net Maximum Capacity. A de-rating starts when the unit is not capable of reaching 100% capacity. The available capacity is based on the output of the unit and not on dispatch requirements. The de-rating ends when the equipment that caused the de-rating is returned to service, whether it is used at that time by the operators or not.

More than one de-rate can occur at one time. It is important to list each event list in order of its impact with the least amount of impact shown before the next de-rate with more impact[2].

i Planned

A de-rating that is scheduled well in advance and is of a predetermined duration.

ii Maintenance

A de-rating that can be deferred beyond the end of the next weekend but requires a reduction in capacity before the next Planned Outage. A de-rating can have a flexible start date and may or may not have a predetermined duration.

iii Forced

A de-rating that requires an immediate reduction in capacity.

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2 Generating Availability Data System, DATA REPORTING INSTRUCTIONS, page III-14.

Docket No. UM-1355
Exhibit PPL/402
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

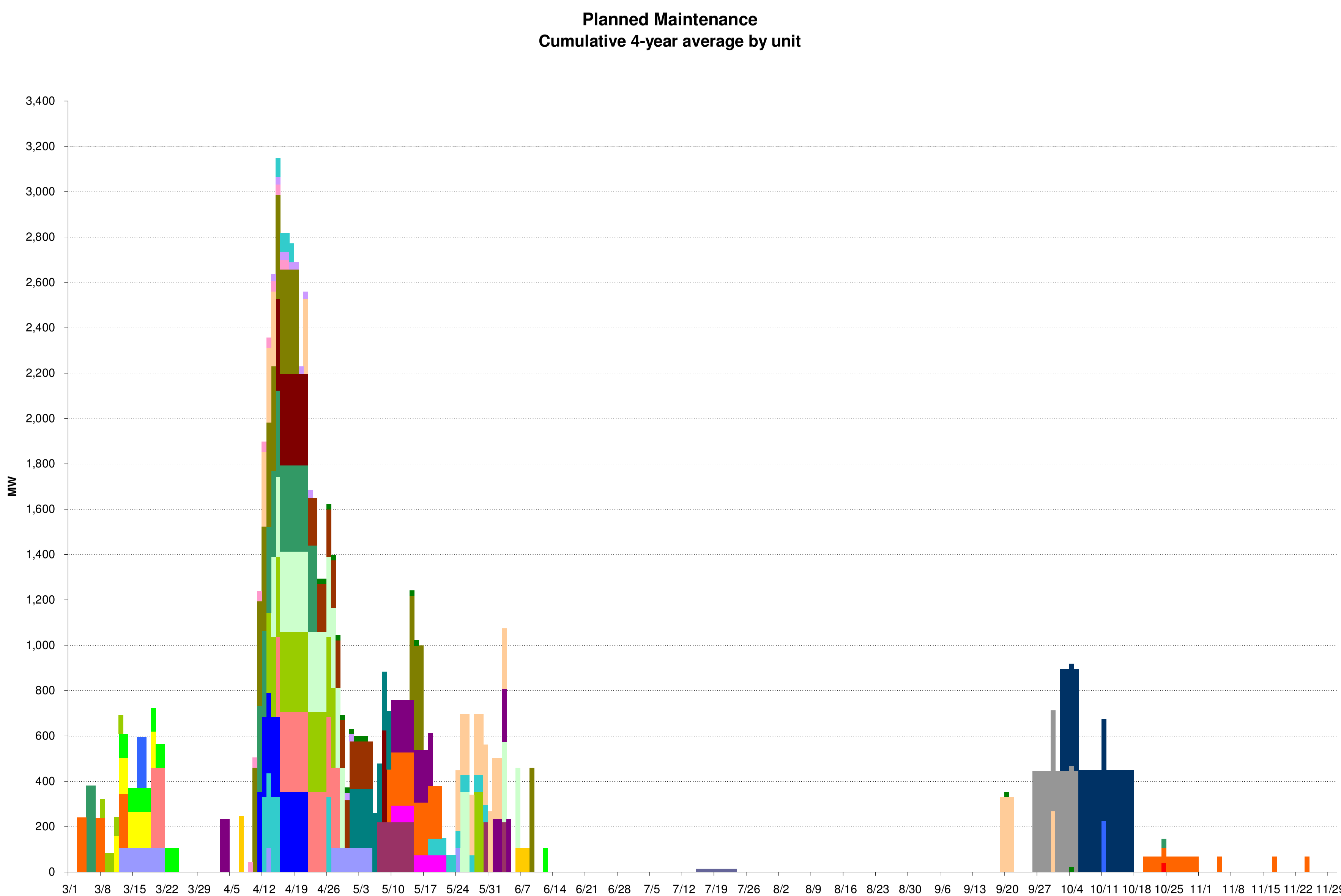
PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

ICNU Planned Maintenance Proposal

May 2009

Exhibit PPL/402
Duvall/1



Docket No. UM-1355
Exhibit PPL/403
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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

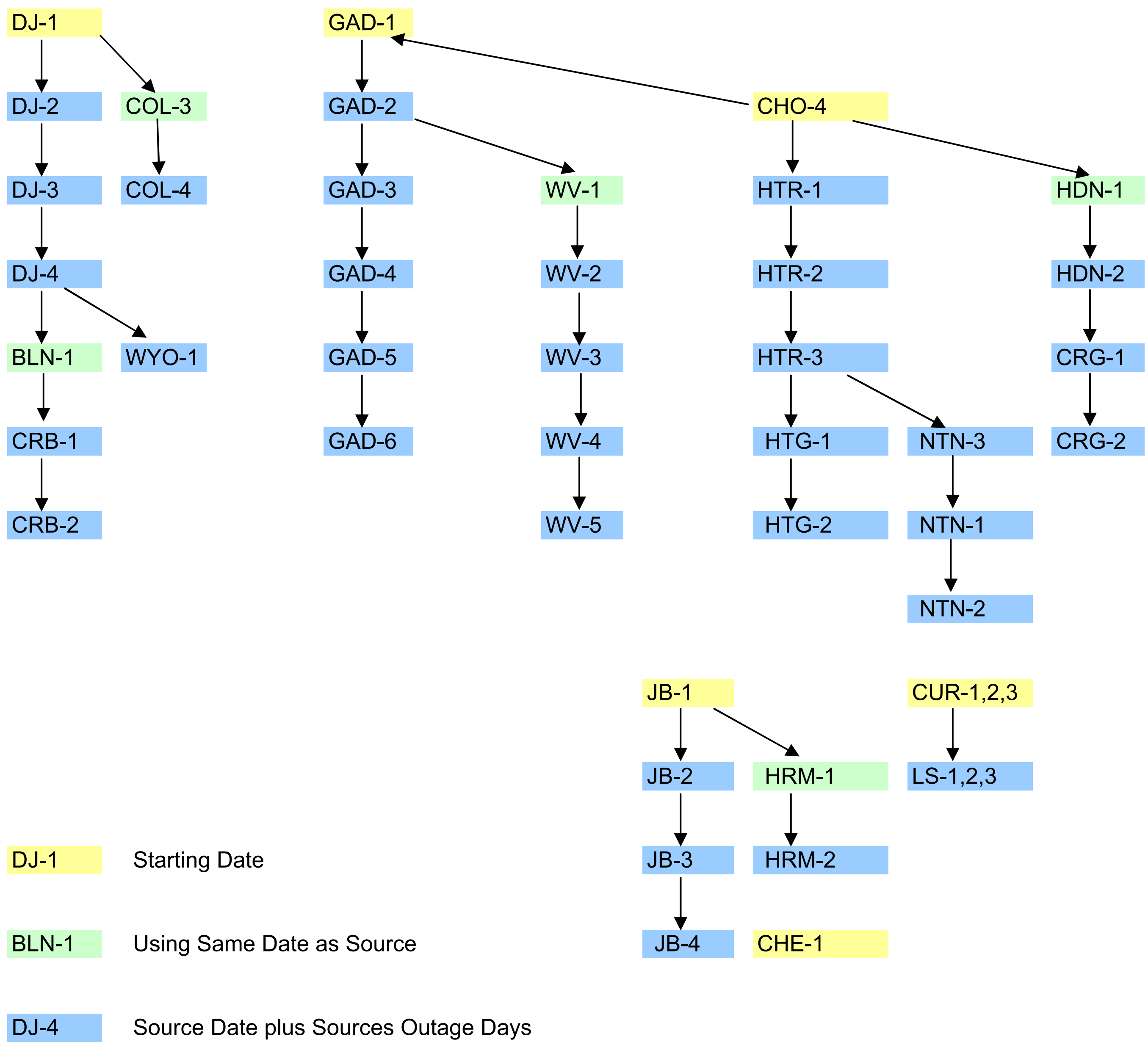
PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

PacifiCorp Planned Maintenance Tree

May 2009

Progression of Maintenance



Docket No. UM-1355
Exhibit PPL/404
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

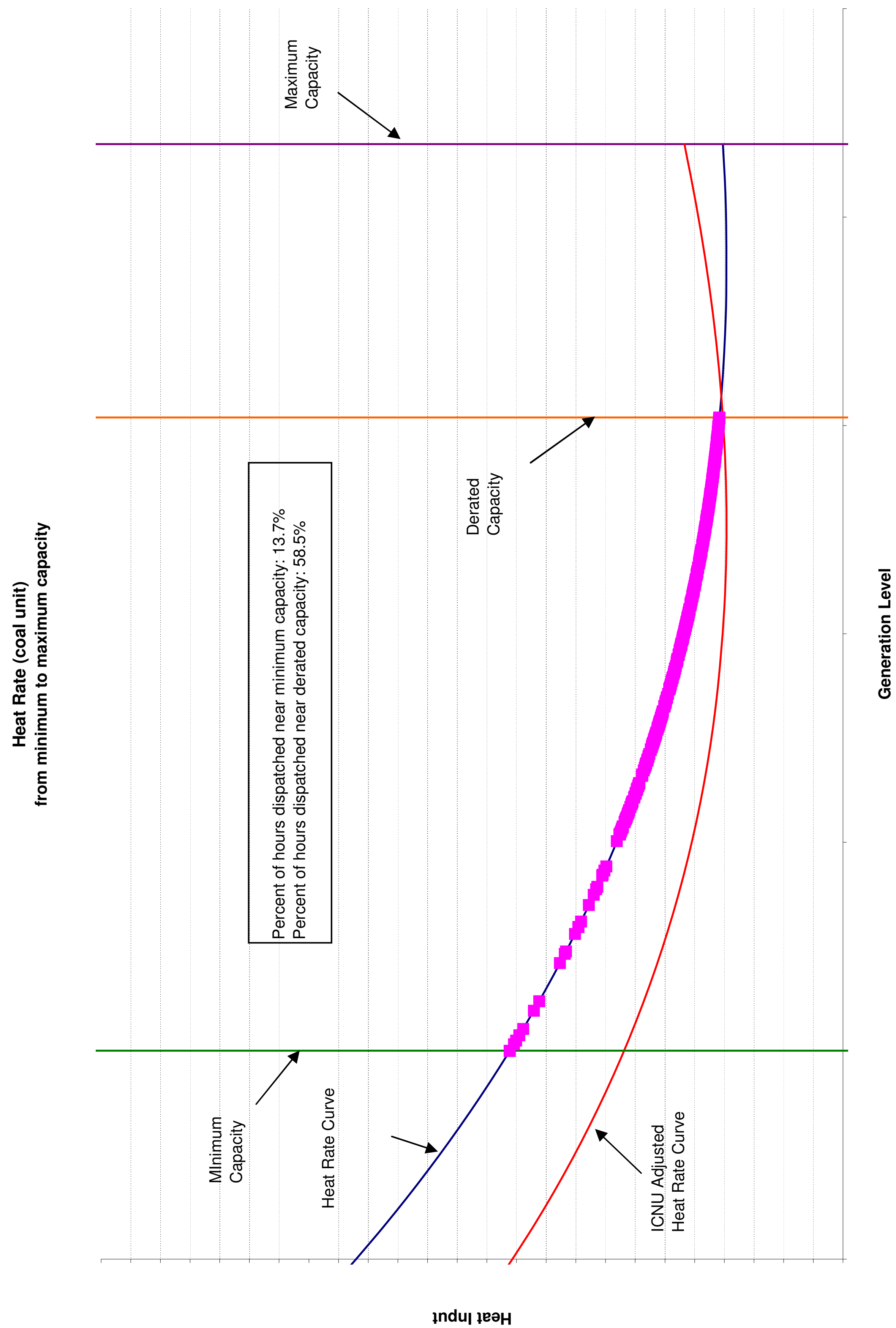
OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Coal and Gas Heat Rates

May 2009


Heat Rate (coal unit)
from minimum to maximum capacity
Percent of hours dispatched near minimum capacity: 13.7%
Percent of hours dispatched near derated capacity: 58.5%
Maximum Capacity
Derated Capacity
MInimum Capacity
Heat Rate Curve
ICNU Adjusted Heat Rate Curve
Generation Level
Heat Input

Heat Rate (gas unit)
from minimum to maximum capacity