PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 25, 2008

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: Docket No. UE 199
PacifiCorp's 2009 Transition Adjustment Mechanism
Rebuttal Testimony and Exhibits

PacifiCorp (dba Pacific Power) submits for filing an original and five copies of PacifiCorp's 2009 Transition Adjustment Mechanism (TAM) Rebuttal Testimony and Exhibits.

It is respectfully requested that all communications related to this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Ste. 2000
Portland, OR 97232
oregondockets@pacificorp.com

Katherine A. McDowell
McDowell & Rackner PC
520 SW 6th Ave, Ste 830
Portland, OR 97204
Katherine@mcd-law.com

Ryan Flynn
Legal Counsel
825 NE Multnomah Street, Ste 1800
Portland, OR 97232
Ryan.flynn@pacificorp.com

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

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

By fax: (503) 813-6060

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

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

Very truly yours,

Andrea L. Kelly /KS

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: UE 199 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of July, 2008, I caused to be served, via E-Mail and Overnight Delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

SERVICE LIST
UE-199

Lowrey R. Brown (C)(W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
lowrey@oregoncub.org

Robert Jenks (C)(W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
bob@oregoncub.org

Jason Eisdorfer (C)(W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
jason@oregoncub.org

Irion A. Sanger (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
ias@dvclaw.com

Katherine A. McDowell (W) (C)
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
Katherine@mcd-law.com

Jason W. Jones (C)
Department of Justice
Regulated Utility & Business Section
1162 Court St, NE
Salem, OR 97301-4096
Jason.w.jones@state.or.us

Kevin Higgins (W) (C)
Energy Strategies LLC
215 State Street, Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Ryan Flynn (W) (C)
PacifiCorp
825 NE Multnomah, Suite 1800
Portland, OR 97232
Ryan.flynn@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Kelcey Brown (C)
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97301
Kelcey.brown@state.or.us

Randall J. Falkenberg (C)
PMB 362
8343 Roswell Road
Sandy Springs, GA 30350
consultrfi@aol.com

Peter J. Richardson (W) (C)
Richardson & O'leary
PO Box 7218
Boise, ID 83707
peter@richardsonandoleary.com

Greg Bass (W)
Sempra Energy Solutions LLC
101 Ash Street HQ09
San Diego, CA 92101
gbass@semprasolutions.com

Alvin Pak (W)
Sempra Energy Solutions LLC
101 Ash Street HQ09
San Diego, CA 92101
apak@sempraglobal.com

Carrie R Meyer

Carrie Meyer
Coordinator, Administrative Services

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

2009 TRANSITION ADJUSTMENT MECHANISM (TAM)

Rebuttal Testimony and Exhibits

July 2008

Case UE-199
Exhibit PPL/106
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Gregory N. Duvall

July 2008

Q. Are you the same Gregory N. Duvall who provided direct testimony in this proceeding?

A. Yes.

Purpose and Summary

Q. What is the purpose of your testimony?

A. My testimony has two parts; a Transition Adjustment Mechanism ("TAM") update and corrections section and a rebuttal section.

First, in the TAM update section, I provide contract, fuel and forward price updates to the Company's net power costs and incorporate two new renewable resources that will be in service by the end of the year. I also explain data corrections to the April filing. These corrections include correcting for the point of delivery to Mid-Columbia ("Mid-C") for the Goodnoe Hills wind facilities, adding the Company's filed wind integration charge for wind resources under contract that were not included in the April filing, and corrections to the wind profiles of the Glenrock and Rolling Hills wind facilities.

Second, in the rebuttal section of my testimony, I address the following issues:

- The proposed adjustments from intervenor direct testimonies that the Company agrees to incorporate, at least in part, into net power costs. These include the use of shut-down screens, similar to what Mr. Falkenberg proposed, to correct commitment dispatch logic in the Generation and Regulation Initiatives Decision Tools ("GRID") model for the Currant Creek and Lake Side plants; removal of uneconomic dispatch of call option contracts, if any; elimination of monthly and weekly modeling of forced outages in favor of annual outage derate modeling; removal of gas resources from the Company's ramping adjustment; and an adjustment to the market cap assumptions in calculating the Transition Adjustment, as proposed by Mr. Kevin C. Higgins.

- The proposed Staff and intervenor adjustments that the Company contests, which include Ms. Kelcey Brown's adjustment removing the hydro forced outages; Mr. Randall J. Falkenberg's adjustments to de-optimize the dispatch of the Sacramento Municipal Utility District ("SMUD") and Black Hills sales contracts and to change the price imputed for the SMUD contract, add the Biomass non-generation agreement, modification of the planned outage schedule, use of de-ration modeling, changes to the hydro modeling (VISTA), inclusion of non-firm transmission, changes to California ISO fees, inclusion of transmission imbalance charges, and removal of SP15 transmission area in GRID; and Mr. Higgins' adjustment to the weighted value of energy in calculating the Transition Adjustment.

Q. Using the TAM updates, data corrections and the adopted adjustments, have you recalculated the Company's forecast net power costs ("NPC") for 2009?

A. Yes. System normalized NPC are now $1.190 billion for the test period, a $60.8 million increase from the system NPC forecast of $1.129 billion in my direct testimony. Exhibit PPL/107 summarizes the cost impact of the TAM updates, data corrections and adopted adjustments on a total company basis.

Q. What is the increase in forecast net power costs on an Oregon-allocated basis?

A. As illustrated on Exhibit PPL/108, on an Oregon-allocated basis the Company's forecasted normalized net power costs for calendar year 2009 are approximately $304.3 million, an increase of $15.7 million from the April filing of $288.6 million. This would result in an overall increase to rates of approximately 6 percent.

Q. What are the primary drivers for the increases in net power costs since the Company's filing in April?

A. The increase reflected in the TAM update is almost entirely attributable to higher prices for electricity, coal and natural gas. The cost increases are mitigated by two new wind facilities and the extension of the termination date for the Condit Hydro license.

Q. Please describe the environment for net power costs now facing the Company.

A. The June 30, 2008 Official forward price curve used in this update is over 25 percent higher than the December 31, 2007 Official forward price curve used in Company's April filing. The Company has not experienced rising net power costs of this magnitude since the Western energy crisis.

Q. Is the Company's experience regarding increased net power costs unique or transitory?

A. No. At its meeting on June 19, 2008, the Federal Energy Regulatory Commission ("FERC") discussed the causes and potential duration of rising electricity costs.

The presentation by the analysts from FERC's Office of Enforcement stated "that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country." It also showed that the forward prices for July and August of 2008 were significantly higher than last years, and indicated that "[t]here is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years."

As discussed at the Oregon Commission's July 15, 2008 natural gas outlook meeting, similar trends are apparent in the natural gas markets, with many gas utilities expect to file double-digit increases to rates in their purchased gas adjustment mechanisms for 2009.

Q. Mr. Falkenberg suggests that the Commission use the Company's 2009 budgeted system NPC as a benchmark for this filing. Does this make sense?

A. No. The Company agrees that it is important to review relevant benchmarks in setting NPC in this case. In the volatile, rising power cost environment now facing the Company, however, benchmarking the filing against the Company's historical budget estimates only serves to demonstrate that energy market costs are increasing much faster than any one predicted. A more accurate set of benchmarks can be found in the Company's most recent actual NPC.

Q. What are the Company's most recent actual system NPC?

A. The Company's actual system NPC for 2007 were $975 million, $140 million higher than NPC in rates from UE 179.

In UE 191, the Commission set the 2008 TAM at $980 million. The

Company's most recent actual NPC for the twelve months ending May 31, 2008 were approximately $1.055 billion. The Company's actual NPC for 12 months ending May 31,2008 are already $75 million above the $980 million system NPC set in the 2008 TAM.

Q. Are actual NPC benchmarks available on an historical basis?

A. Yes. Exhibit PPL/109 shows the Company's actual NPC as compared to NPC in Oregon rates since 2000. This exhibit shows that the Company has consistently spent more on net power costs to serve its customers than it has recovered in rates. However, the trend and magnitude of this situation in recent years is the most significant aspect of this exhibit.

Q. What is your general observation about what has caused the Company's actual costs to outpace the level included in rates?

A. NPC have been steadily increasing industry-wide. In addition, GRID and other linear programming power cost models fail to capture all actual costs by assuming optimal system operation with some, but not all, of the constraints that the Company faces on a real-time basis.

These factors are exacerbated when, as in this case, intervenors selectively use historical trends for certain costs inputs without a corresponding look at costs trends that would increase costs; propose modeling adjustments without a demonstration that the Company's modeling approach is imprudent or unreasonable; and propose arguments designed to reduce NPC for procedural or technical reasons, ignoring the reality of the NPC cost increases the Company faces.

Q. What is your conclusion on the operative standard by which the Commission should set NPC?

A. The Commission should review the reasonableness of the Company's proposed NPC using the same prudence standard it applies to other aspects of the Company's business operations. As a matter of prudence, the Company will generally seek to optimize its system. But there are limits on what the Company can achieve in this regard in real-time operation. The Commission should not hold the Company to a level of perfection in the operation of its system that is impossible for any utility to achieve. For this reason, actual cost benchmarks are an important reality check in this process.

TAM - Net Power Costs Updates and Corrections

Q. Please describe the TAM net power costs updates.

A. The net power costs updates include the following contract data and forward price curve updates. Exhibit PPL/107 provides a summary of the impact on total Company net power costs for each of these items.

- Condit hydro generation – net power costs are updated to reflect the extension of the Company's license to operate the Condit facility until October 1, 2009.
- Borah Brady wheeling rate – net power costs are updated for the wheeling rate received from Idaho Power Company.
- Transmission Contract between the Bonneville Power Administration ("BPA") and PacifiCorp – net power costs are updated to include a new contract entered into by the Company for 75 megawatt transmission

capacity to deliver the Company's generation to a new load substation located on the BPA transmission system. The new substation is required to reliably serve growing loads in the Yakima, Washington service area.

- Hermiston Losses – the update reflects the latest information available on the amount of losses related to wheeling the Hermiston generation through BPA's transmission system.
- Short-term firm transactions – net power costs are updated to reflect new short-term firm purchase and sales contracts entered into since the April filing.
- Official forward price curve – the official forward prices are updated to reflect the June 30, 2008 curves, which includes updated indexed contracts, mark to market value of natural gas transactions, financial swaps, as well as reshaped hydro generation.
- Coal costs – net power costs are updated to incorporate the latest changes in Company's coal contracts and mining operations.
- Sierra Pacific energy price – net power costs are updated for the demand and energy prices of the sales contract to Sierra Pacific for the last two months of the contract term.
- Mid Columbia contract costs – the Company's share of the costs of the purchased power contracts with the Douglas and Chelan Public Utility Districts ("PUDs"), for generation from the Wells and Priest Rapids projects, respectively, are updated based on the latest proformas from the PUDs.

- BPA wind tariff charges – the wind integration costs are updated to include the expected BPA tariff applicable to wind projects. This tariff will apply to the Company's Leaning Juniper and Goodnoe Hills wind facilities that are interconnected to BPA's transmission system.
- Seven Mile Hill II – net powers costs are updated to reflect the generation from this 19.5 MW wind facility located in Wyoming, which is expected to be in service in December 2008 and will be included in the Company's update to the Renewable Adjustment Clause ("RAC") filing in Docket UE 200, and
- Glenrock III – net powers costs are updated to reflect the generation from this 39 MW wind facility, which is expected to be in service in December 2008 and will be included in the Company's update to the RAC filing in Docket UE 200.

Q. Please describe the coal cost increases noted above in greater detail.

A. Coal price increases at our generation facilities are being driven by a variety of factors, including increases in commodity costs (oil, steel and gas), the impact of contract re-openers, and higher mine operating costs. This update reflects an increase in the cost of fuel supplied by the Arch coal purchase due mainly to a price re-opener as well as contract escalation; increases in coal costs from the Jim Bridger mine due to increased depreciation and depletion associated with the underground mining operations, increased royalty costs, as well as increased labor, benefits and overall operating costs; and an increase at the Deer Creek mine caused by a combination of increased costs in materials and supplies, increased labor, benefits, insurance and royalties.

Q. Please describe the corrections included in the Company's net power costs filing.

A. As shown on Exhibit PPL/107, this filing includes three corrections. First, the delivery point of the Goodnoe Hills wind facility has been moved to the Mid-C transmission area modeled in GRID based on the arrangement in the wheeling contract that the Company has with the BPA. Second, the Company has now included the generation under all contracts from wind facilities in the calculation of wind integration charges. The third correction is to the wind profiles of the Glenrock and Rolling Hills wind facilities in the first six-hour block in 2009. In total these corrections increase system net power costs by approximately $1 million.

Q. Are there any other corrections?

A. Yes. The Company also made corrections to the outage rates of Currant Creek and Lake Side. However, this will be addressed later in my testimony.

Q. Are these corrections within the scope of the TAM?

A. Yes. The Company believes that data corrections are within the proper scope of the rebuttal testimony in this case. The Company has always filed corrections to known errors in its rebuttal case, whether these errors work in customers' favor or the Company's, and it made such data corrections in its last TAM rebuttal filing in UE 191.

Rebuttal

I. Fully or Partially Conceded Adjustments

GRID Commitment Logic (ICNU)

Q. Please explain Mr. Falkenberg's commitment logic adjustment.

A. Mr. Falkenberg contends that the GRID model's commitment logic is imperfect because, at certain times, it dispatches two of the Company's gas plants, Currant Creek and Lake Side, in a manner that fails to optimize the system. Specifically, he complains that GRID dispatches the gas plants at times when there is no firm transmission available in the model to take the power to loads or markets. While GRID backs down the gas plants to minimum levels, it also backs down coal plants to compensate for the excess power. This causes NPC to increase.

Q. What specific adjustments does Mr. Falkenberg propose?

A. Mr. Falkenberg proposes a "night-time screen" for both Currant Creek and Lake Side, manually preventing the units from dispatching during certain hours at night, along with an additional screen to shut down Currant Creek for the two months in April and May.

Q. Does Mr. Falkenberg ask the Commission to require changes to the GRID model for future cases?

A. Yes. Before the Company files its next TAM or general rate case, Mr. Falkenberg asks the Commission to require the Company to fix the commitment logic in GRID.

Q. What is your response to the underlying commitment logic issue?

A. While the Company disagrees with much of the rationale and rhetoric of Mr.

Falkenberg's adjustment, it does agree that GRID should simulate normal prudent operation of the system. Absent unusual circumstances, the Company would not run its gas units in a manner that would cause its less expensive coal plants to back down. To the extent that GRID systematically dispatches resources in this manner, the Company agrees that the model needs to be adjusted.

Q. How has the Company addressed this issue to date?

A. The Company has addressed this issue in two ways. First, when it has become clear that the model is systematically dispatching units in an uneconomic manner, the Company has applied manual workarounds (i.e. turning off the ability of the model to dispatch a certain unit at a certain time). Second, the Company has worked to refine and improve GRID's commitment logic in the last two upgrades to the model to eliminate the need for such manual workarounds.

Q. Has the most recent version of GRID completely resolved this issue?

A. No. The most recent version of GRID addresses and ameliorates the issue but did not resolve it in all cases.

Q. Mr. Falkenberg insinuates that the Company has continuously refused to disclose the commitment logic problem to regulators. Is this correct?

A. No. Mr. Falkenberg stated on page 20 in his testimony that "[a]s early as Wyoming Docket No. 20000-ER-03-198, the Company's witness, Mr. Mark T. Widmer, acknowledged that the combustion turbines were dispatched incorrectly in GRID …." The Company has openly addressed the issue by turning off the dispatch of certain units, assuming different fuel costs for committing the gas-fired units, agreeing to adjustments in its rate cases, and developing GRID version

6.2.

Q. Mr. Falkenberg claims that the Company "still refuses to acknowledge" the nightly screens that the Company has used were to correct the commitment logic problem. How do you respond?

A. GRID assumes optimization with some constraints, but not all, that limit the real operations of the Company's system. One of the constraints is that the Company does not have an unlimited market to sell into during the night hours, which is why the market sizes in the graveyard hours are capped at what the Company actually experienced. In addition, the Company limited the operation of the gas-fired units during the night hours, especially the peakers, because they normally do not operate during that time.

Q. How does the Company propose to address the commitment logic issue in this case?

A. The Company agrees that it should apply a manual workaround to prevent systematic uneconomic dispatch of the Currant Creek and Lake Side plants.

With respect to Currant Creek and Lake Side, similar to Mr. Falkenberg's recommendations, the Company proposes to apply a 6-hour night-time screen to these units, plus to shut down Currant Creek during the month of April. The workaround lowers system NPC by approximately $26 million. However, the additional unit plant start-ups result in an increase in fuel and operations and maintenance ("O&M") expense, which increases expenses by $5 million and $3.8 million, respectively.

Q. Does Mr. Falkenberg propose a corresponding adjustment for increased fuel and O&M expense to account for the costs of the additional start-ups modeled?

A. No. On page 28 in Exhibit ICNU/100, Mr. Falkenberg agrees that there is incremental start-up fuel and O&M expenses resulting from the daily cycling of the units; however, he concludes that these costs are already included in base rates and are outside the scope of the TAM.

Q. Do you agree that the additional start-up fuel and O&M expense are already included in base rates and are outside the scope of the TAM?

A. Only partially. These are additional costs that are not included in base rates. Start-up fuel costs for gas plants are part of NPC and are properly included in the TAM. The additional O&M expenses are outside the traditional scope of the TAM. However, if the Commission accepts other adjustments proposed by Staff and ICNU that are outside the scope of the TAM, then consistency requires that the Commission also include the O&M expense associated with the additional start-ups. The NPC included in this rebuttal testimony only include the additional start-up fuel expense.

Q. How does the Company plan to address this commitment logic issue in future filings?

A. The Company is reviewing refinements to the modeling of the normalized net power costs in GRID, as well as replacement of GRID with another model. Until this work is complete, the Company will apply manual workarounds to the GRID model to address uneconomic dispatch. Mr. Falkenberg acknowledged in the

Company's recent Utah general rate case that he did not question whether the Company was making good faith efforts to address this problem and that the manual workarounds were an acceptable interim solution.

Outage Rate Modeling (ICNU)

Q. What are Mr. Falkenberg's adjustments to outage rate modeling?

A. Mr. Falkenberg makes two adjustments to outage rate modeling, which he categorizes as either corrections or modeling enhancements. His proposed corrections, which include blended average outage rates for Currant Creek and Lake Side, the removal of the ramping adjustment for the Gadsby units and revision to the weekend/weekday split, decrease system NPC by $4.3 million. A separate adjustment, which includes proposed annual forced outage rates with weekday and weekend split and removal of ramping for all units, decreases system NPC by an additional $2.6 million. As explained below, the Company agrees in part to Mr. Falkenberg's outage rate modeling adjustments.

Monthly and Weekly Modeling of Forced Outages

Q. Please explain Mr. Falkenberg's proposed adjustment to monthly outage rate modeling.

A. The proposed adjustment would reverse the company's <u>monthly</u> modeling of forced outage rates and substitute <u>annual</u> forced outage rates. Mr. Falkenberg believes his adjustment is appropriate because monthly modeling is not industry practice and outages are random.

Q. Do you agree with the proposed adjustment?

A. Yes, but only if the weekday/weekend split for modeling outages is also eliminated. If the Company reverts to more general, annual modeling of forced outages because of the fundamental randomness of such events, there is no justification for the retention of the weekday/weekend split in the forced outage rates. Mr. Falkenberg admitted in the Company's recent Utah general rate case that the weekday/weekend difference only "amounts to around 1 percent." Because this difference is so small, it is not discernable in a monthly comparison of historical outage rates by unit, such as that set forth in Exhibit PPL/110.

Q. Does the change to annual outage rates constitute a methodological change outside the scope of the TAM?

A. No. In UE 191, the Commission reviewed adjustments to the Company's calculation of its forced outage rates. However, if the Commission believes that this change is outside the scope of the TAM and should be taken up in the UM 1355 investigation of the modeling of forced outages or in a general rate case, as Staff suggests for hydro outage rate methodology changes, then the Company would propose to retain its current modeling of monthly outages with weekday/weekend split.

Q. What is the impact of reverting to an annual forced outage rate and eliminating the weekday/weekend split in the forced outage rate?

A. Combined with the removal of gas units from the Company's ramping adjustment discussed below, this change decreases system NPC by approximately $4 million.

Q. **Does this adjustment include the corrections to the outage rates of Currant Creek and Lake Side you mentioned earlier?**

A. Yes.

Ramping

Q. Please describe Mr. Falkenberg's ramping adjustment.

A. The Company has added a ramping adjustment to its NPC to account for decreased availability when generating units are started-up and shut-down. Mr. Falkenberg proposes to remove this adjustment**.**

Q. Please explain why the Company included its ramping adjustment.

A. The logic in GRID assumes that generation units can go from full load to zero instantaneously when being ramped down for maintenance, outages or economic shutdown and can go from zero to full load instantaneously when restarted after planned maintenance, economic shutdown and forced outages. In reality, units are not available at full load when ramping down for maintenance, outages or economic shutdown and when ramping up from outages due to the physical capabilities of the units. Generation is lost while a unit ramps to the minimum level required for synchronizing with the power grid and when ramping up to full load, as well as when a unit is being shut down for maintenance or economic shutdown. The Company's ramping adjustment simply reduces thermal availability to reflect generation not available due to ramping.

Q. Mr. Falkenberg claims that the Company's ramping adjustment is contrary to industry practice. Please respond.

A. The only unusual aspect about the Company's treatment of ramping is that it requires a manual adjustment in GRID, since GRID does not include the ability to ramp units as a part of its dispatch logic. However, there is nothing novel in factoring in ramping into a generation unit's availability.

Q. Mr. Falkenberg claims that the Company lost this issue in the last Washington rate case. Is this true?

A. It is true that the Washington Commission ruled against the Company on an adjustment that they referred to as ramping. The order makes clear, however, that the analysis of this issue focused on calculation of the forced outage rate, not on the reasonableness of adjusting availability for ramping.

Q. Mr. Falkenberg complains that the Company's method of calculating ramping can mischaracterize a gas unit being held in reserve as ramping. Please respond.

A. First, to clarify any confusion on this point, the only gas units included in the Company's ramping adjustment are Gadsby units 1, 2 and 3, which are steam units by design. There are no other gas units included in the ramping adjustment.

Second, the Company agrees that its current ramping calculation could inadvertently cover a gas plant being held for reserves. To adjust for that possibility, the Company agrees to remove the Gadsby units from the ramping adjustment. The impact of this adjustment is included in the adjustment reverting to the annual forced outage rate.

Q. Mr. Falkenberg alleges that this Commission denied a similar adjustment proposed by Portland General Electric ("PGE"). Please comment.

A. The Commission disallowed an adjustment that PGE proposed in the calculation of the forced outage rate for the Colstrip plant in Docket UE 139 to account for "missing generation." The Commission rejected PGE's adjustment on the basis that PGE arbitrarily assigned these unexplained generation shortfalls to its forced outage rate. The only connection between the PGE adjustment and the Company's proposed ramping adjustment is that PGE theorized that up and down ramping periods might be one of several sources of the missing generation. The Commission did not reject an adjustment for ramping in UE 139; instead it rejected a general adjustment for unexplained system aberrations.

Call Options (ICNU)

Q. Please explain the proposed adjustment for a call option contract.

A. Mr. Falkenberg's adjustment proposes to disallow costs associated with Morgan Stanley contract p272158 during the month of June 2009 because the contract did not dispatch. Mr. Falkenberg supports the adjustment on the basis that the Company accepted a similar disallowance in last year's Oregon TAM case.

Q. Do you agree with Mr. Falkenberg's proposed adjustment?

A. No. Mr. Falkenberg is seeking to disallow the call option costs without demonstrating the imprudence of these costs. The Company executed the contract to meet demand and ensure reliable service by providing physical delivery of energy into our load area during periods of increased demand and/or transmission constraints when prices are higher. So even if the contract is not dispatched in GRID, it can provide customers a real benefit in the event of a change in the Company's system and should be included in the Company's net power costs. Mr. Falkenberg's adjustment can be likened to not paying an insurance premium in the months that there were no damage claims. Removal of the call premium in months that the contract did not dispatch is unreasonable.

Q. How do you respond to Mr. Falkenberg's contention that the call option is dispatching uneconomically?

A. The Company agrees that the call option contract should not be dispatched in a manner that increases NPC and agrees to remove the costs associated with uneconomic dispatch using a monthly screen. This adjustment reduces system NPC in the July TAM update by $0.3 million. However, the Company notes that the contract may not have this impact in the updated GRID runs.

Market Caps in the Transition Adjustment (Sempra)

Q. Please explain Mr. Higgins' proposal to relax market cap assumptions in the calculation of the Transition Adjustment.

A. Mr. Higgins recommends that when calculating the impact of the 25 megawatt load decrement, the Company should relax the market capacities by 15 and 10 megawatts at Mid-C and COB markets, respectively. The parties included a similar provision in the UE 170 Stipulation.

Q. Do you agree with this recommendation?

A. Yes, as long as the mechanism ensures the Company's customers remain unharmed by the changes in the value of the transition credits.

II. Company Responses to Fully Contested Adjustments

Hydro Forced Outage Rates (Staff)

Q. Please explain Ms. Brown's proposed adjustment for hydro outage rates.

A. Ms. Brown proposes to exclude hydro forced outages from Company's net power cost calculation, stating that this is a methodology change, more appropriately made in a general rate case. The adjustment reduces system NPC by $11.1

million, or $2.9 million on an Oregon-allocated basis.

Q. Why did the Company add forced outage rates for its hydro plants?

A. Prior to this filing, the Company did not have the data set necessary to include hydro in the four-year rolling average used to calculate forced outages. Now that the Company has the data, it included it in this filing without making any change in the underlying methodology for calculating the forced outage rate. Updates to forced outage rates and adjustments related to outage rates have always been within the scope of the TAM. Indeed, in UE 191, the Commission accepted an adjustment that ICNU made to the forced outage rates, over the Company's objection that the adjustment should be addressed as a policy matter in UM 1355, the Commission's investigation of forced outage rate modeling.

Q. Is Ms. Brown's adjustment correct numerically?

A. No. Ms. Brown overstated the amount of lost hydro generation that is caused by the inclusion of hydro forced outages. Ms. Brown derived her adjustment based on the change in the Company's normalized hydro generation from UE 191. As the Company stated in response to a Staff data request, only a "portion of the difference is due to incorporation of forced outages for the modeled hydro." Ms. Brown attributed the majority of the difference to including forced outages, when, in fact, it caused only a fraction of the difference. In addition, the calculation of this adjustment needs to start from identifying the hours that are lost due to forced outages, which impacts how stream flow would be optimized in VISTA to produce the additional hydro generation.

Q. What do you recommend to the Commission on this adjustment?

A. The Commission should reject this adjustment. The Company's modeling of hydro forced outages is consistent with its modeling of other generating resource outages. Inclusion of hydro in the forced outage rates increases the overall accuracy of the Company's NPC.

SMUD Pricing (ICNU)

Q. Please explain Mr. Falkenberg's proposed SMUD pricing adjustment.

A. Mr. Falkenberg argues that the current revenue imputation at $37 per megawatt hour of the sales contract with the SMUD is not compensatory and should be reset and indexed to the actual contract price. He contends that the up-front payment received from the contract should be recovered over the term of the contract and imputes a price of $42 per megawatt-hour. The adjustment would reduce system NPC by $1.8 million. He also recommends that this amount should be updated each year based on the projected SMUD contract price.

Q. Does Mr. Falkenberg mention the fact that the Commission previously rejected his SMUD pricing adjustment in UE 116?

A. No. In Order No. 01-787, the Commission rejected ICNU's adjustment to increase the $37 per megawatt-hour imputed price associated with the SMUD contract.

Q. Has Mr. Falkenberg presented any new evidence regarding the prudence of the contract that was known at the time the transaction was consummated but was not considered in the Commission's earlier decision on the prudence of this contract?

A. No.

Q. Do you have any other concerns about this proposed pricing adjustment?

A. Yes. The ongoing review of prudence is not consistent with normal regulatory policy and cost-based ratemaking. If this type of adjustment were to be made, it would also need to be applied generally which would result in significant imputed price increases to contracts such as the Mid-C purchase power agreements and the Hermiston fuel agreements. The Company does not recommend this approach.

SMUD and Black Hills Power Contract Modeling

Q. Please explain Mr. Falkenberg's proposed modeling adjustments to the SMUD and Black Hills Corporation contracts.

A. The adjustments propose to substitute actual data for optimized data. The GRID model assumes for normalized purposes that SMUD and Black Hills Corporation ("Black Hills") will maximize the value of their contracts and take the power from the Company in a manner that optimizes the value of the contract to them given the inputs to the optimization model. Mr. Falkenberg proposes to adjust the inputs to reflect actual contract operations, thus removing these two "option" contracts from being subject to the optimization logic of GRID. The adjustments result in a $2.4 million and $2.5 million reduction in total company NPC, respectively.

Q. Do you agree with the proposed adjustments?

A. No. The adjustments have two specific problems. First, the adjustments depart from modeling power costs on a normalized basis. Second and more important, they are examples of one-sided, selective adjustments to the model. If this type of modeling adjustment were adopted, then consistency and fairness require its application to all other purchase or sale contracts as well as generating resources which have "option" features or are modeled in a similar fashion to these two sales contracts.

Q. How did Mr. Falkenberg justify his selection of SMUD and Black Hills contracts in his adjustments?

A. When asked why only these two contracts were selected for his adjustments, Mr. Falkenberg explained that he "did not review all the sales contracts in GRID," and "there are only a handful of call option sales/price shaping sales contracts in GRID." See page 1 of Exhibit PPL/111, ICNU response to Data Request 1.7. It is obvious that Mr. Falkenberg is only interested in making adjustments to one side of the optimization in GRID. Optimization of the Company's system operations decreases NPC on a net basis. Mr. Falkenberg has not proposed "de-optimization" across the board, which would increase NPC and undermine Mr. Falkenberg's arguments on GRID commitment logic. Nor has he provided any justification for selective "de-optimization" of the SMUD contract and Black Hills contract. Moreover, Mr. Falkenberg was unable to provide any documentation or support for his adjustment for the Black Hills Contract. See page 2 of Exhibit PPL/111, ICNU response to Data Request 1.9. His arguments to change the modeling of these two contracts should therefore be rejected.

Hydro Modeling (ICNU)

Q. Please describe Mr. Falkenberg's hydro modeling adjustment.

A. Mr. Falkenberg repeats his proposed adjustment in UE 191 and alleges that the Company's VISTA model for modeling normalized hydro generation overstates the likelihood of extreme hydro conditions. He recommends that the Commission eliminate this alleged bias by changing the weights for the wet, median and dry cases to those he developed based upon historical data. He also recommends that the Commission require the Company to file a complete 40 water year study in its next TAM or general rate case; otherwise the Company should use median hydro only. This adjustment lowers modeled NPC $2.3 million on a total company basis.

Q. Why did the Company incorporate the VISTA model into its power cost modeling?

A. The Company began using the VISTA model to more accurately reflect changing operational characteristics of river systems compared to using a simple historical average of generation.

Q. How does the Company model normalized hydro using the VISTA model?

A. VISTA currently has three exceedance levels: 25 percent, 50 percent and 75 percent. A 25 percent exceedance level means that the Company has a 25 percent chance of exceeding that level of generation (i.e., a "wet" year); a 75 percent exceedance level means the Company has a 75 percent chance of exceeding that level of generation (i.e., a dry year). To set normalized power costs, the Company runs the GRID model using the three exceedance levels and averages the results.

Q. What is Mr. Falkenberg's objection to this approach?

A. Mr. Falkenberg argues for exclusive use of the median, or 50 percent exceedance level. He claims that the Company's current approach inaccurately assumes the same water conditions will occur on all river systems throughout the test period. He also claims that the Company agreed to use of the median case in the most recent Oregon TAM.

Q. Please respond.

A. The Company averages the results of the three different GRID studies using a range of exceedance levels to normalize the outcome of forecasted hydro generation by capturing the different water conditions that can occur on any river system at any time of year. The assumptions this approach makes around the correlation of river systems are appropriate, given that there is some level of correlation and the purpose of the modeling is to normalize hydro conditions.

Q. Did the Company agree to sole use of the median case in the last TAM case?

A. No. Mr. Falkenberg argued in UE 191 that the Company should use the "mean" instead of the "median" in this modeling. The Company opposed this position and argued for continued use of a median case. The Company did not agree, however, to cease reliance on other exceedance levels in its hydro modeling.

Q. Did the Commission ultimately reject Mr. Falkenberg's claim that the Company's hydro modeling was biased in the Company's favor?

A. Yes. In Order No. 07-446, the Commission found no evidence that the "model tends to skew the result in some manner that is more favorable to the Company."

Mr. Falkenberg has presented no new evidence in this case; he is simply making the same arguments that were previously unconvincing to the Commission.

Q. Should the Commission adopt Mr. Falkenberg's proposed approach to hydro modeling?

A. No. The Company's approach to hydro modeling fairly approximates the likelihood of wet, dry and normal water years in setting normalized NPC.

Q. How do you respond to Mr. Falkenberg's request that the Commission require the Company to prepare a full 40 water year study?

A. When the Company calculates the three exceedence levels, the entire available generation history of the hydro facilities is used. The 40 water years that Mr. Falkenberg referred to is a subset of that data base. It is ironic that Mr. Falkenberg would prefer to switch to a smaller sample size for normalized hydro generation when he argues that the Company greatly overstates the severity and likelihood of the "wet" and "dry" hydro scenarios. If Mr. Falkenberg believes that some of the dry conditions in the history are no longer applicable and the more recent history is a better representation of the normalized hydro generation, then the question is whether 40 water years are more accurate than an even shorter history, say four years.

Generating Unit Representation in GRID (ICNU)

Q. Please explain Mr. Falkenberg's proposed heat rate modeling and minimum loading deration adjustments.

A. Mr. Falkenberg argues that the Company's heat rate curves and unit minimum capacities should be adjusted as a result of the use of the deration method to model forced outages. The proposed adjustments result in a reduction to system NPC of $6.2 million.

Q. Do you agree with these adjustments?

A. No. The Company has been using the deration method to model forced outages for over 25 years without the proposed mathematical alterations to the heat rate curves and minimum unit capacities proposed by Mr. Falkenberg. If this was such a glaring error in the methodology, it seems that one of the Company's commissions would have raised an objection to it by now.

Q. Are the examples in Mr. Falkenberg's Exhibit ICNU/111 realistic?

A. No. Mr. Falkenberg's attempt to support his proposed heat rate adjustment is based on the flawed assumption that forced outages result in plants being either on and running at their most efficient level or off. In reality, plant outages result in units running at all different output and efficiency levels depending on the nature of the outage. Mr. Falkenberg's adjustment does not recognize that many forced outages are partial forced outages. He assumes that each plant runs at its most efficient heat rate during partial forced outages, which is simply impossible.

His analogy equating the forced outages to fractionally owned units is unfounded. Responding to the Company's request to explain the differences between fractionally owned units and derated units in the context of adjusting the heat rate for derates, Mr. Falkenberg objected to the request on the ground of it being "vague and ambiguous."

Q. Does the Company apply deration to shared plants?

A. Yes. After adjusting the plant output to the appropriate share, the Company uses the deration method on shared plant in exactly the same manner as it is done for wholly owned plants.

Q. Mr. Falkenberg stated that "PGE applies the very type of technique" that he is proposing. Please comment.

A. Mr. Falkenberg failed to point out the differences between the Company's system and PGE's system and that the Commission supports PacifiCorp's method for use by the Company. PGE has three coal units, while the Company has 26. PGE does not model heat rate curves, while the Company does. PGE's three coal units tend to be in the money most of the time which means they are likely on or off. Just these facts alone would imply that the PGE method, one that assumes coal units are either on or off and never run at levels in between, would significantly understate the costs associated with running a large fleet of coal units over a diversified geography with loads in six states and would therefore be inappropriate for PacifiCorp.

Q. Is Mr. Falkenberg's proposed reduction to the unit minimum capacity reasonable?

A. No. The plant minimum is the plant minimum. Adjusting this makes no sense at all and appears to simply be a mathematical ploy to lower net power costs in the model.

Q. What is your recommendation regarding the heat rate curve modeling and minimum loading deration adjustments proposed by Mr. Falkenberg?

A. The Commission should reject these unfounded proposed adjustments. The adjustments are based on flawed analysis and are inconsistent with the application of the deration method the Company has used and this Commission has employed for many years.

Biomass Non-Generation Contract (ICNU)

Q. Please describe Mr. Falkenberg's adjustment for the Biomass Non-Generation contract.

A. Mr. Falkenberg recommends a reduction to Company's NPC by $0.5 million on the expectation that the previous contract with Biomass would be available again for the test period.

Q. Do you agree with the adjustment?

A. No. Mr. Falkenberg's entire justification for this adjustment is that "(i)n each of the past three years the Company has agreed to a non-generation agreement with the Biomass project." The Company does not currently have a 2009 contract with Biomass, and is not clear if there will be one and in what terms. Such adjustment is inconsistent with the process of determining normalized net power costs under the TAM. Therefore, it should be rejected by the Commission.

Planned Outages (ICNU)

Q. Please describe the adjustments to planned plant outages proposed by Mr. Falkenberg.

A. Mr. Falkenberg contests the schedule the Company used for its planned outages and substitutes his own schedule by using a version of the actual outage schedules from the past four years. Mr. Falkenberg's adjustment decreases system NPC by $5.0 million.

Q. Do you agree with the adjustment methodology that Mr. Falkenberg is proposing?

A. No. Mr. Falkenberg's proposed outage schedule is unreasonable and unworkable. He has proposed it as a means of reducing net power costs without showing that the Company's proposal, which is based on the Company's historical outage scheduling practices, is unreasonable. His method involves running four GRID runs, each with a one-year historical maintenance schedule and then averaging the results together.

Q. Why is this alternative schedule unworkable?

A. One example would be the screens used by Mr. Falkenberg for addressing the commitment logic and option contracts. In theory, the screens would have to be developed separately for each of the four GRID studies and may be different across the four studies. However, I don't believe Mr. Falkenberg reformulated his screens for each of the four studies. Another complexity would be trying to estimate the impact of a particular change. It would involve comparing one set of four studies with another set of four studies. In addition, there would not be one final GRID study.

Q. What other problems exist with Mr. Falkenberg's proposal?

A. Normalizing maintenance requires the maintenance of all plants in the test period which is not what Mr. Falkenberg has done in his proposal. In each of his four studies, only a subset of the generation fleet is maintained. Additionally, Mr. Falkenberg bases his proposed method on history, without any recognition of changes to the resource mix of the fleet and emerging maintenance issues relating to air quality and other environmental issues.

Q. What other concerns do you have with Mr. Falkenberg's proposed planned outage adjustment?

A. His adjustment significantly reduces net power costs by shifting plant maintenance from one month to another when there is no showing that the Company's proposal is unreasonable, deviates from general historical practice or has resulted in the over recovery of NPC. Aggressive modeling assumptions on maintenance lower the cost of prudent plant maintenance costs and can affect the reliability of the system. For all of these reasons, the Commission should reject Mr. Falkenberg's planned maintenance adjustment.

SP15 and Cal ISO Wheeling Expense (ICNU)

Q. Please describe Mr. Falkenberg's proposed adjustment to the SP15 and the Cal ISO wheeling expenses.

A. Mr. Falkenberg recommends the Company's system net power costs be reduced by $6.4 million if the Commission rejects his adjustment to include non-firm transmission in GRID. He argues that the SP15 transmission area is not connected to any other transmission areas modeled in GRID, and as such, the customers do not benefit from the Company's hedging strategy using the SP15 transmission area. This adjustment removes the SP15 transmission area and the Cal ISO charges from the Company's net power costs.

Q. Is his argument valid?

A. No. As Mr. Falkenberg stated, many of the transactions at SP15 are financial hedges that do not require physical deliveries, and only a portion of the physical delivery comes from outside the SP15 area. The argument that "the benefits of the Company's hedging strategy cannot be realized in a test year prepared up to 13 months in advance of the ultimate transactions" is without basis. It is correct that the projected net power costs will not capture the actual market conditions in the test period. However, the model is designed to simulate the market conditions at that time by dispatching thermal units against market, and by including system balancing sales and purchases. The short positions included in the Company's calculation may not be closed at the actual market prices during the test year, but they are closed at the simulated market conditions consistent with any other positions.

Q. What other concerns do you have regarding this adjustment?

A. This proposed adjustment is illogical and unreasonable. It is no more sensible than an adjustment that removes Mid-C or Palo Verde as a trading hub from the GRID model. In addition, it is proposed as a fallback adjustment if his proposed non-firm wheeling adjustment is not accepted; yet it has nothing to do with non-firm wheeling. As explained by the Company, the transactions at SP15 are part of the overall strategy to hedge the long position at an illiquid market in a liquid market. The hedges are not entirely for economic reasons, but for risk of not being able to balance the system. Due to the nature of a model with perfect foresight, there doesn't seem to be any such risk in GRID. This in only one of the realities that a model can not capture.

Q. Should the Cal ISO wheeling expenses be removed?

A. No. The Cal ISO wheeling expenses that Mr. Falkenberg referred to are the total

Cal ISO charges that include fees in addition to wheeling expenses. These fees are incurred whenever the Company needs to transfer power through the Cal ISO system, whether for going into or coming out of the SP15 transmission area, or passing through the Cal ISO area.

Q. Is Mr. Falkenberg's adjustment correct numerically?

A. No. Mr. Falkenberg actually understated what he intended to do by including changes that are not related to removing the SP15 transmission area and the Cal ISO charges. For example, when he removed the non-firm transmission that he built in from the comparison GRID scenario to create the no-SP15 GRID scenario, he not only removed the non-firm transmission linked to SP15 but also between other transmission areas. As a result, the increases in NPC from the comparison scenario are overstated. Mr. Falkenberg also appears to have included the adjustment to EFOR in his no-SP15 scenario.

Q. What is your recommendation regarding Mr. Falkenberg's adjustment on the SP15 transmission area?

A. The Commission should reject this adjustment because Mr. Falkenberg's supporting arguments and calculations are without merit.

Q. Mr. Falkenberg also recommended an adjustment to how the Company calculated the Cal ISO fees for the test period. Do you agree to this adjustment?

A. No. The Company estimated the fees based on the latest information available and the assumption that the amount of activities with the Cal ISO has been increasing since the latter part of last year. The Company's estimate is reasonable.

Transmission Imbalance (ICNU)

Q. Please describe the adjustment for transmission imbalances.

A. Mr. Falkenberg proposed an adjustment to include the benefit of transmission imbalances in the normalized net power costs, stating that those imbalances are a low-cost resource to the Company. The adjustment reduces system NPC by $3 million.

Q. Do you agree with his adjustment?

A. No. It is not true that the Company benefits from those imbalances.

Q. What are transmission imbalances?

A. Transmission imbalances refer to the deviation of scheduled generation and actual generation. Because the Company is the control area operator, it is responsible to balance the load and resources within the control area at any given time. The amount of energy actually generated by the third party generators often does not match what they schedule, as a result, the Company has to supply power to cover shortages, or absorb surplus generation.

Q. How are other parties charged or paid for the imbalances?

A. Based on the FERC tariff, if the deviation is within one percent, the Company is paid or pays the market prices, depending on whether the Company needs to deliver or receive power for the differences between scheduled and actual generation. If the deviation is beyond one percent, the Company is paid with a ten percent "premium" or pays a ten percent "discount" from the market prices, depending on the directions of the differences. When the deviation caused by non-intermittent generators becomes even bigger, the "premium" and "discount" becomes bigger.

Q. Doesn't that mean the Company receives the benefits?

A. No. When the Company pays other parties or gets paid by other parties for imbalances, it is only to "make whole" for the costs that the Company has incurred. These imbalances occur within-the-hour, where there is no market for such transactions. As the result, the Company has to either back down its own low-cost generation or have additional generation available to cover the load.

Q. Is there another problem with this adjustment?

A. Yes. Consistent with the perfect foresight assumed in GRID, there are no transmission imbalances in its normalized modeling. Therefore, there would not be any so called "benefits" to the Company.

Q. Is Mr. Falkenberg's adjustment correct numerically?

A. No. Mr. Falkenberg used the Company's transmission imbalances that the Company delivered and received, took ten percent of the sum of the two and put into GRID as free energy, which, in essence, changed the net position of the system. For example, if the amount delivered is 100 megawatts and received is 70 megawatts, the net change to the Company's system should be to deliver 30 megawatts. However, in his adjustment, he added the two numbers and multiplied the result by 10 percent to arrive at the adjustment of 17 megawatts of free resource to the Company's system. This is an illogical and incorrect calculation which results in an erroneous result.

Q. What is your recommendation regarding this adjustment?

A. Mr. Falkenberg's adjustment for transmission imbalances should be rejected because his argument is unsupported and his calculations are incorrect.

Transition Adjustment (Sempra)

Q. How does the Company respond to Sempra witness Mr. Higgins' proposal to change how PacifiCorp's transition adjustment is calculated?

A. PacifiCorp is concerned that Sempra's proposal would shift costs to non-direct access customers resulting in cross-subsidization.

Q. Please explain.

A. Mr. Higgins' proposal effectively assumes that PacifiCorp will be able to sell off 100 percent of any freed-up power to market. Mr. Higgins offers no evidence supporting this assumption. Indeed, the GRID model demonstrates that real system constraints make this result unlikely. If the transition credit assumes a result that cannot be achieved, other customers will pay higher costs.

Q. Has the Commission considered this approach in the past?

A. Yes. In fact, for the first few years of direct access, the Company assumed market sales of freed-up power (including transaction costs) to establish the transition adjustment. In 2004 in Order No. 04-516 in UM 1081, the Commission adopted a GRID-based approach for setting PacifiCorp's transition adjustment after the issue was fully litigated. Staff supported adoption of the GRID-based approach.

Q. Do Mr. Higgins' proposed changes to the GRID-based approach cause additional concerns?

A. Yes. The use of one set of assumptions for establishing NPC and another set of assumptions for setting the transition credit could cause unintended consequences, especially in current rising-cost power markets. Mr. Higgins presented no assurances that customers could be protected from such outcomes.

Q. Does this conclude your testimony?

A. Yes.

Exhibit PPL/107
Duvall Exhibit

Case UE-199
Exhibit PPL/107
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

SUMMARY OF CHANGES TO NET POWER COSTS

July 2008

Oregon TAM - UE 199
Total Company Net Power Costs
Update and Rebuttal
July 25, 2008

Oregon TAM 2009 (April '08 Filing)		NPC ($) =	**1,129,101,025**
		$/MWh =	**$ 18.72**

Oregon TAM 2009 (July '08 Filing):

		Impact ($)	NPC ($)
Update, one-off			
1	Condit Hydro Generation	(3,695,541)	
2	Borah Brady Wheeling Rate	525,788	
3	Transmision Contract between BPA and PacifiCorp	1,220,215	
4	Hermiston Losses	(1,119,336)	
5	Short Term Firm Transactions	(12,190,581)	
6	Official Forward Price Curve	42,852,885	
7	Coal Costs	52,410,934	
8	Sierra Pacific II Energy Price	(75,372)	
9	Mid Columbia Contract Costs	356,553	
10	Seven Mile II Wind	(3,290,217)	
11	Glenrock III Wind	(5,003,089)	
12	BPA Wind Integration Charges	917,373	
Correction, one-off			
1	Delivery Point of Goodnoe Wind Facitlity	(3,767)	
2	Wind Integration Charge of Purchased Power Contracts	1,105,031	
3	Wind Profiles of Glenrock and Rolling Hills	(73,640)	
	System balancing impact of all adjustments	12,900,818	
	Total Adjustments from April Filing =	86,838,055	
	Oregon TAM 2009 NPC, prior to adopted adjustments		**1,215,939,080**
Adopted, cumulative			
1	Annual Derates	(4,041,655)	
2	Commitment Logic Screen	(26,300,632)	
	Additional Startup Fuel Costs	4,592,140	
3	Call Options	(312,240)	
	Total Adopted Adjustments =	(26,062,387)	
	Oregon TAM 2009 NPC, July '08 Update		**1,189,876,694**

Exhibit PPL/108
Duvall Exhibit

Case UE-199
Exhibit PPL/108
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

OREGON ALLOCATION OF NET POWER COSTS

July 2008

Allocated NPC to Oregon for 2009 TAM

July 2008 Update

		TOTAL COMPANY				FACTOR			OREGON		
	ACCOUNT	UE-191	CY 2009 FILED	CY 2009 JULY UPDATE		UE-191	CY 2009 FILED	CY 2009 JULY UPDATE	UE-191	CY 2009	CY 2009 JULY UPDATE
Sales for Resale											
Existing Firm PPL	447	24,333,468	24,282,692	24,281,810	SG	25.977%	26.411%	26.411%	6,321,208	6,413,406	6,413,173
Existing Firm UPL	447	26,154,379	25,490,590	25,490,590	SG	25.977%	26.411%	26.411%	6,794,234	6,732,429	6,732,429
Post-Merger Firm	447	2,097,277,718	926,901,220	1,090,894,586	SG	25.977%	26.411%	26.411%	544,818,752	244,807,867	288,120,860
Non-Firm	447	-	-		SE	25.465%	25.525%	25.525%	-	-	-
Total Sales for Resale		2,147,765,564	976,674,502	1,140,666,986					557,934,195	257,953,702	301,266,462
Purchased Power											
Existing Firm Demand PPL	555	72,620,358	71,979,766	73,739,631	SG	25.977%	26.411%	26.411%	18,864,899	19,010,886	19,475,691
Existing Firm Demand UPL	555	50,238,162	47,419,394	47,496,461	SG	25.977%	26.411%	26.411%	13,050,581	12,524,140	12,544,495
Existing Firm Energy	555	93,251,746	88,770,208	92,909,589	SE	25.465%	25.525%	25.525%	23,746,920	22,658,406	23,714,974
Post-merger Firm	555	1,798,247,893	804,581,876	982,337,139	SG	25.977%	26.411%	26.411%	467,138,503	212,501,579	259,449,286
Secondary Purchases	555	-	-	-	SE	25.465%	25.525%	25.525%	-	-	-
Seasonal Contracts	555	9,197,540	9,513,690	10,426,290	SSGC	23.565%	24.488%	24.489%	2,167,404	2,329,710	2,553,315
Other Generation Expense	555	-	3,278,604	5,500,239	SG		26.411%	26.411%	-	865,926	1,452,692
Total Purchased Power		2,023,555,698	1,025,543,538	1,212,409,349					524,968,306	269,890,647	319,190,452
Wheeling Expense											
Existing Firm PPL	565	32,639,496	31,366,571	31,031,711	SG	25.977%	26.411%	26.411%	8,478,901	8,284,360	8,195,919
Existing Firm UPL	565	157,430	172,448	172,448	SG	25.977%	26.411%	26.411%	40,896	45,546	45,546
Post-merger Firm	565	72,742,842	81,123,193	83,334,742	SG	25.977%	26.411%	26.411%	18,896,717	21,425,795	22,009,897
Non-Firm	565	420	144,177	190,077	SE	25.465%	25.525%	25.525%	107	36,801	48,517
Total Wheeling Expense		105,540,188	112,806,389	114,728,978					27,416,621	29,792,502	30,299,878
Fuel Expense											
Fuel Consumed - Coal	501	504,036,230	513,042,882	566,883,629	SE	25.465%	25.525%	25.525%	128,354,785	130,953,100	144,695,836
Cholla / APS Exchange	501	54,138,635	55,371,186	57,393,458	SSECH	23.497%	25.914%	25.899%	12,721,205	14,348,737	14,864,300
Fuel Consumed - Gas	501	20,256,747	7,652,800	23,437,129	SE	25.465%	25.525%	25.525%	5,158,459	1,953,361	5,982,277
Natural Gas Consumed	547	399,872,050	369,250,420	331,998,558	SE	25.465%	25.525%	25.525%	101,828,972	94,250,381	84,741,923
Simple Cycle Combustion Turbines	547	16,906,672	18,666,117	20,150,907	SSECT	23.497%	23.941%	24.342%	3,972,639	4,468,777	4,905,224
Steam from Other Sources	503	3,670,593	3,442,195	3,541,671	SE	25.465%	25.525%	25.525%	934,731	878,613	904,004
Total Fuel Expense		998,880,927	967,425,599	1,003,405,352					252,970,791	246,852,969	256,093,564
Net Power Costs		980,211,249	1,129,101,025	1,189,876,694					247,421,525	288,582,416	304,317,432
									Variance from UE 191:	41,160,891	**56,895,908**
										Variance from April Filed	**15,735,016**

Case UE-199
Exhibit PPL/109
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

NET POWER COSTS IN RATES vs. ACTUAL

July 2008

PacifiCorp
NPC In Rates vs. Actual
Oregon

	2000	2001	2002	2003	2004	2005	2006	2007	2008
NPC in Rates	573.8	984.0	591.7	648.2	598.0	643.6	796.5	834.4	980.2
Actual NPC	841.1	1210.4	677.7	598.2	745.6	782.8	783.2	974.6	
Difference	(267.3)	(226.4)	(86.0)	50.0	(147.6)	(139.2)	13.3	(140.2)	

Case UE-199
Exhibit PPL/110
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

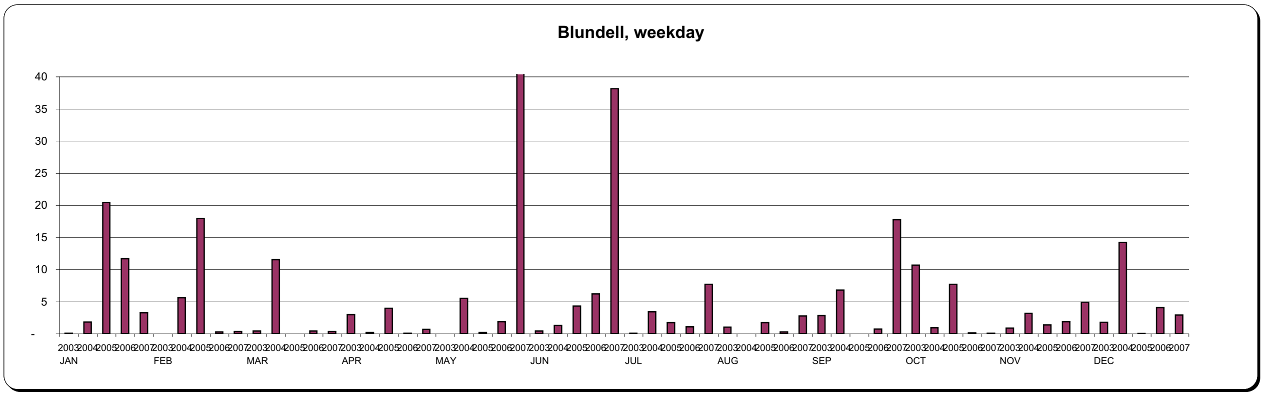
PACIFICORP

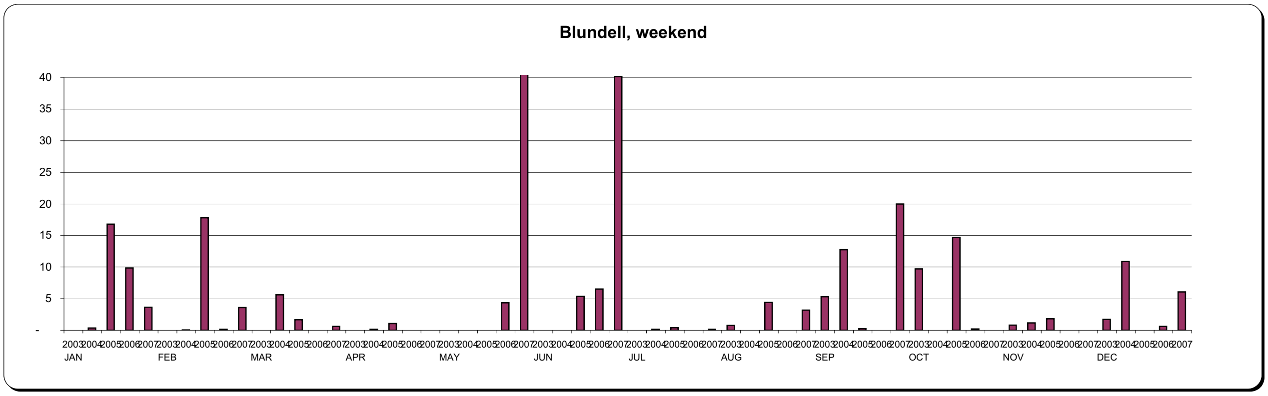
Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

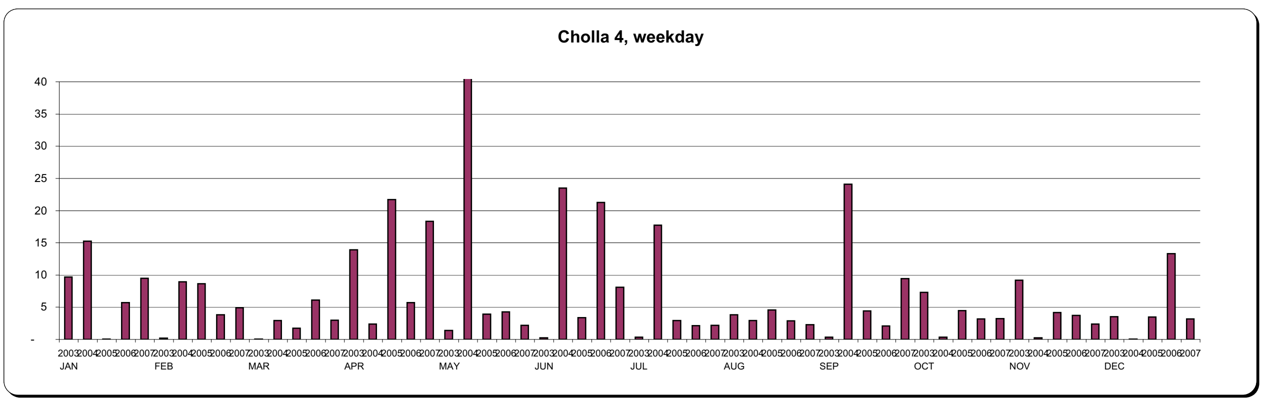
HISTORICAL FORCED OUTAGE RATES

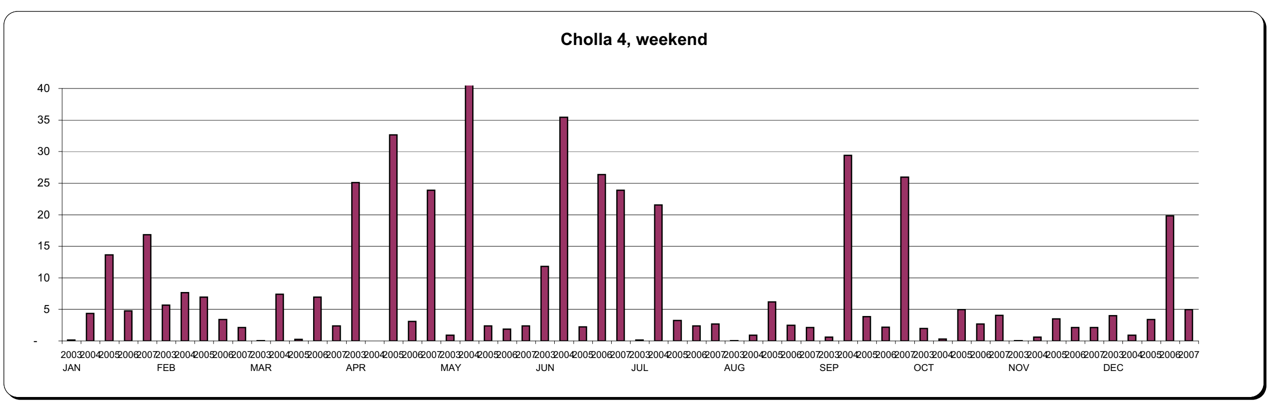
July 2008

5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

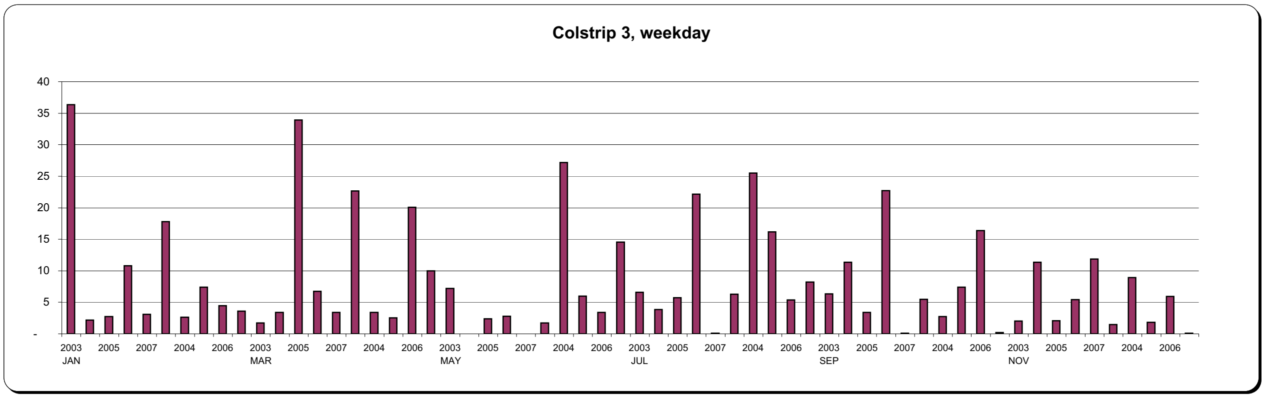


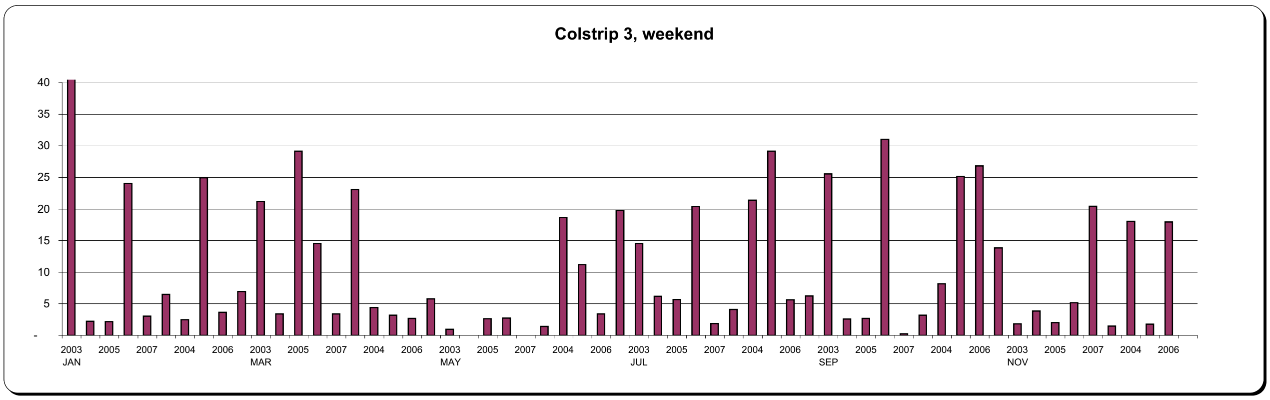


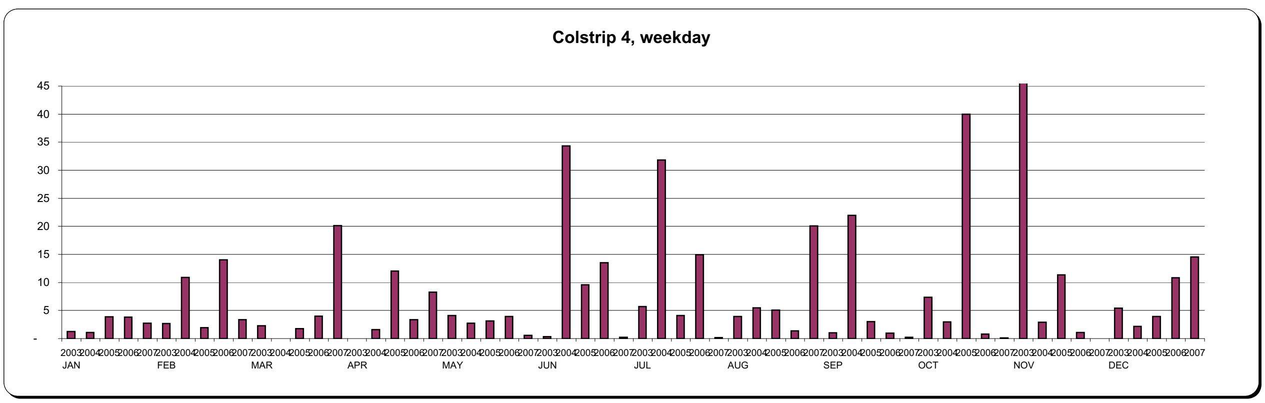




5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month







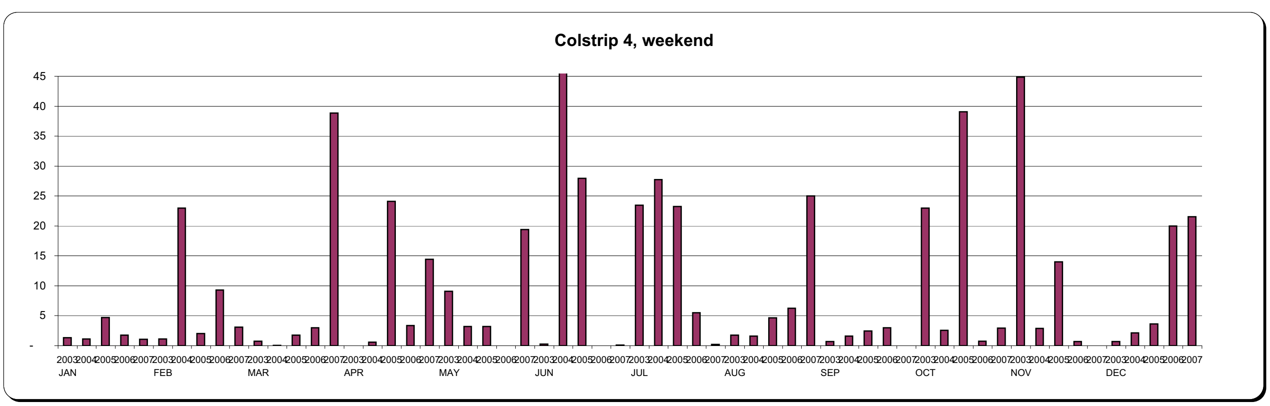
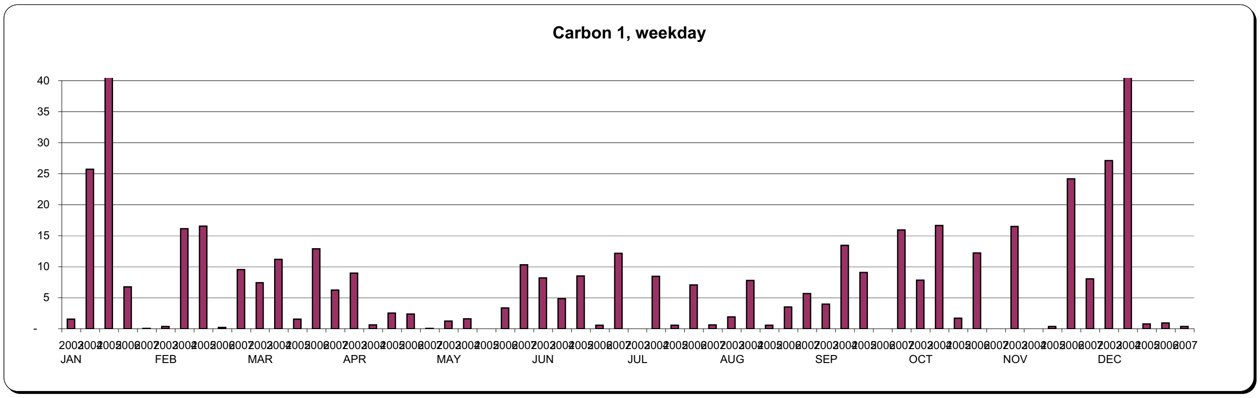
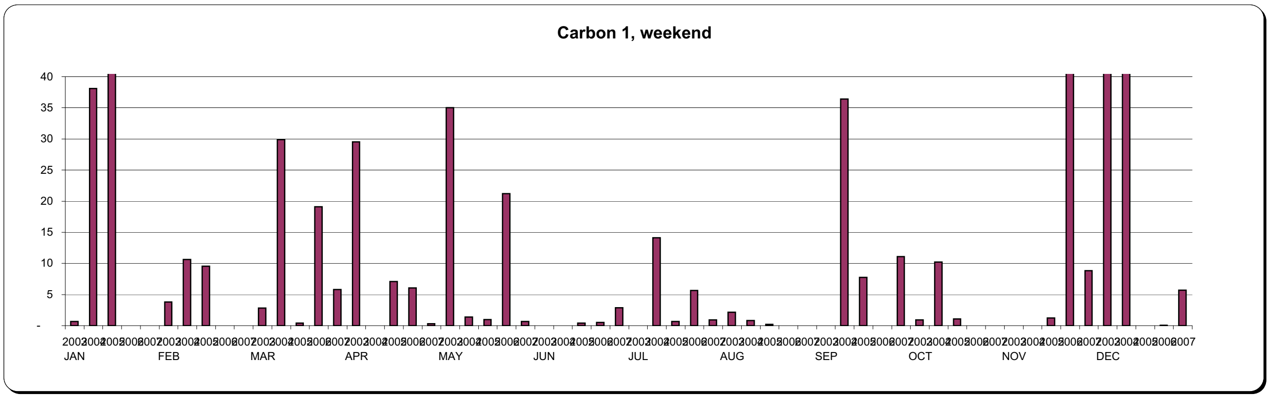
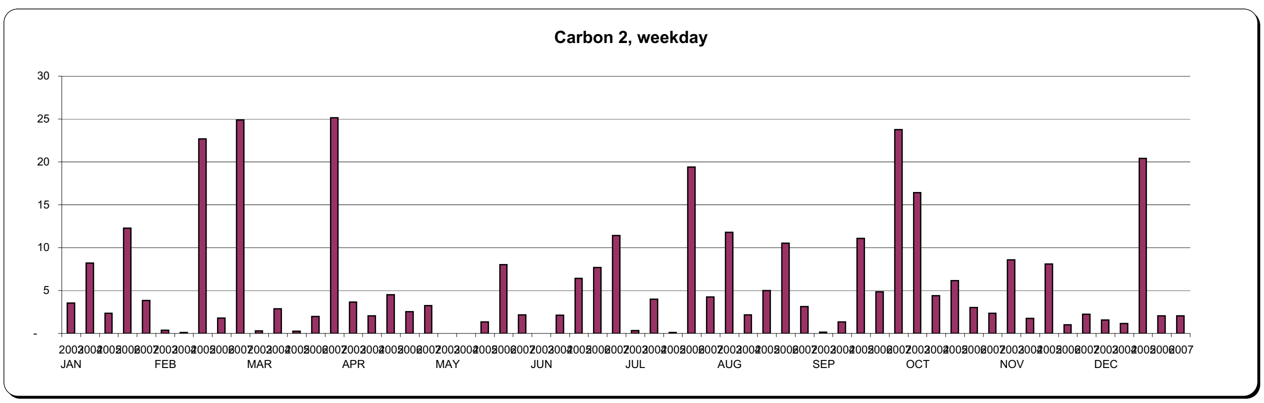


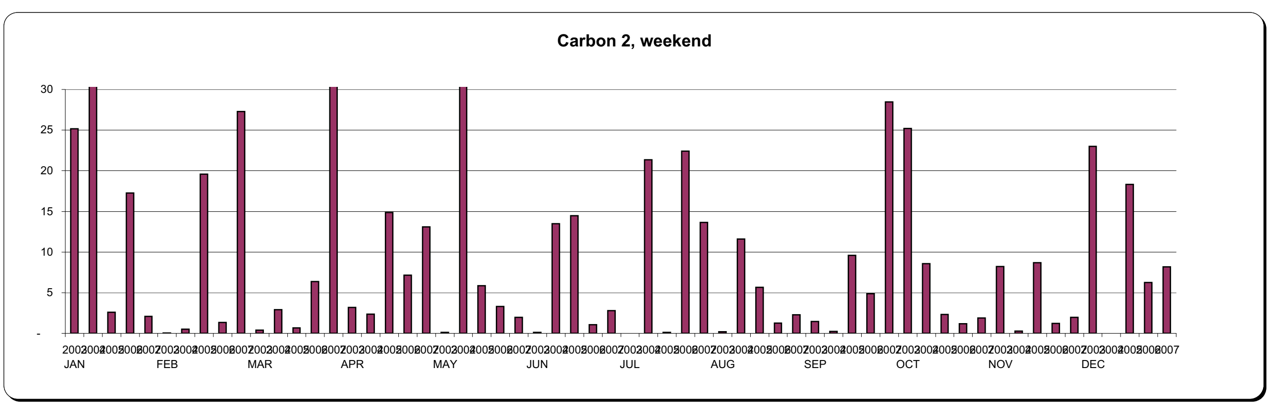
Exhibit PPL/110
Duvall/3

5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

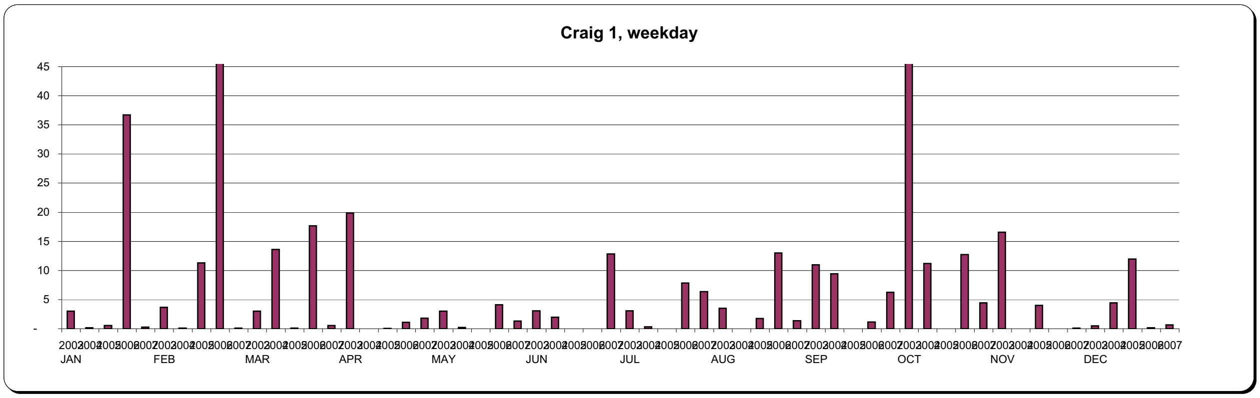


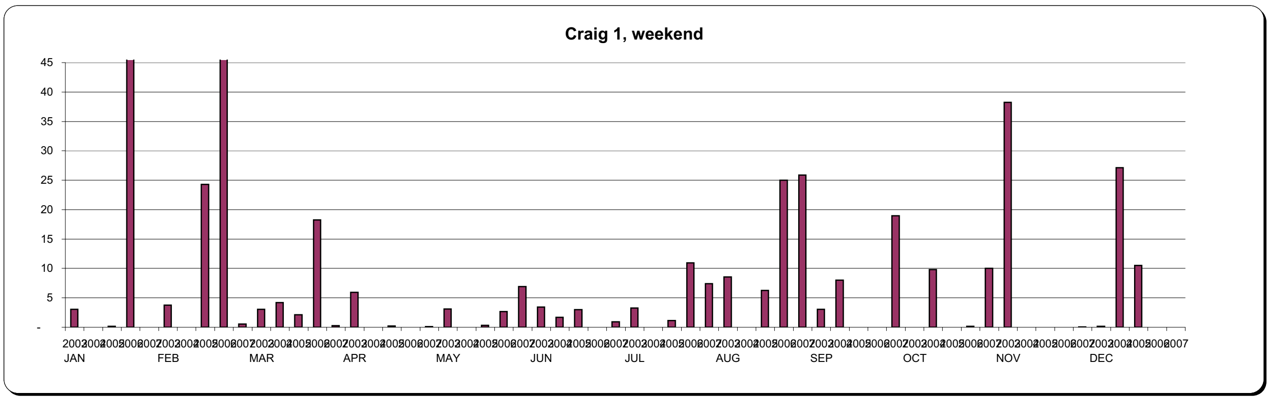


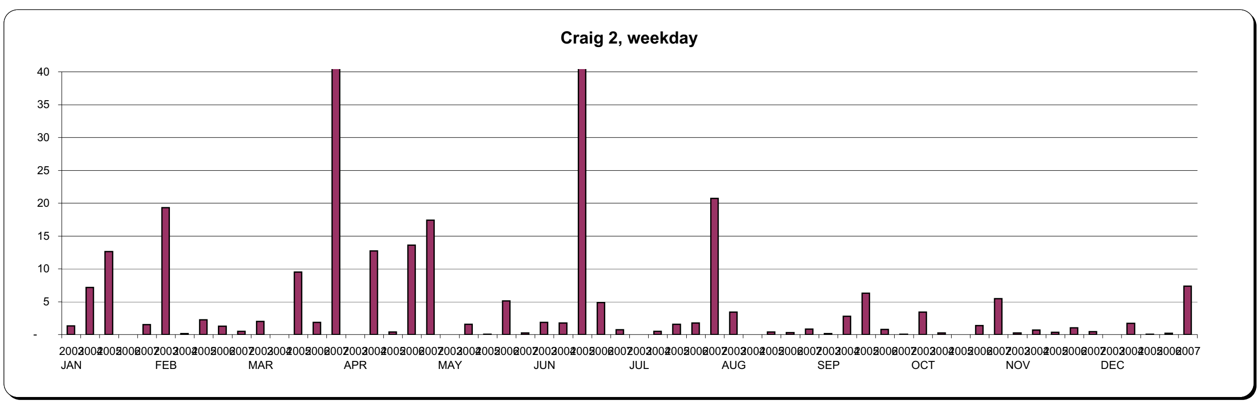


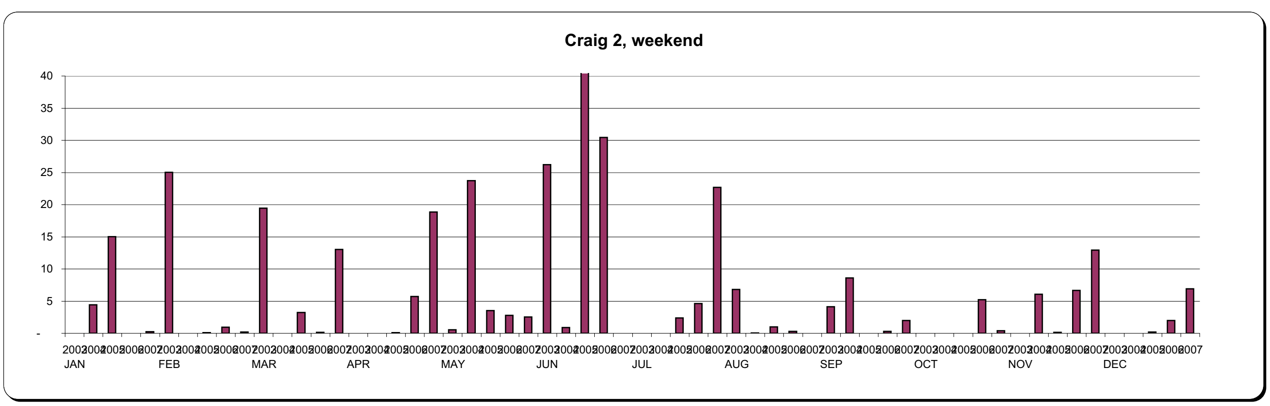


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

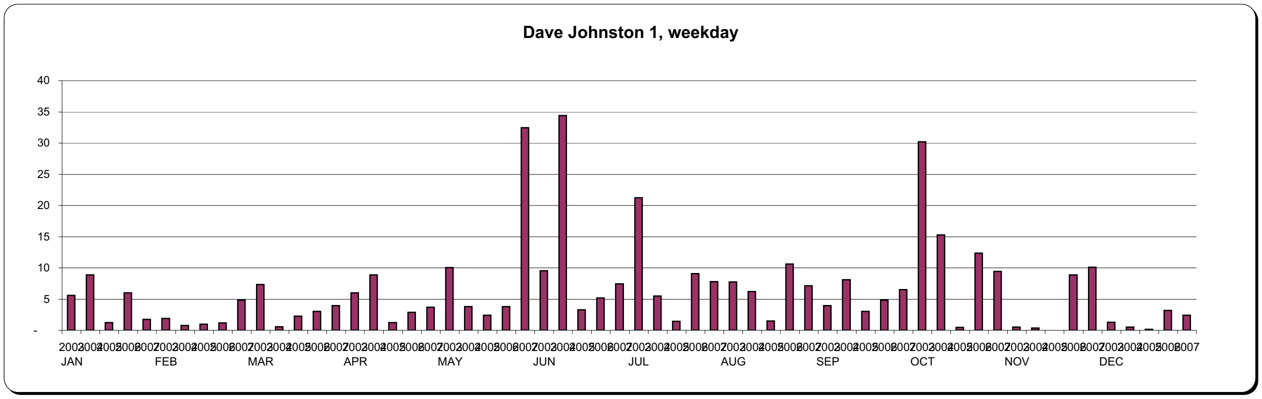


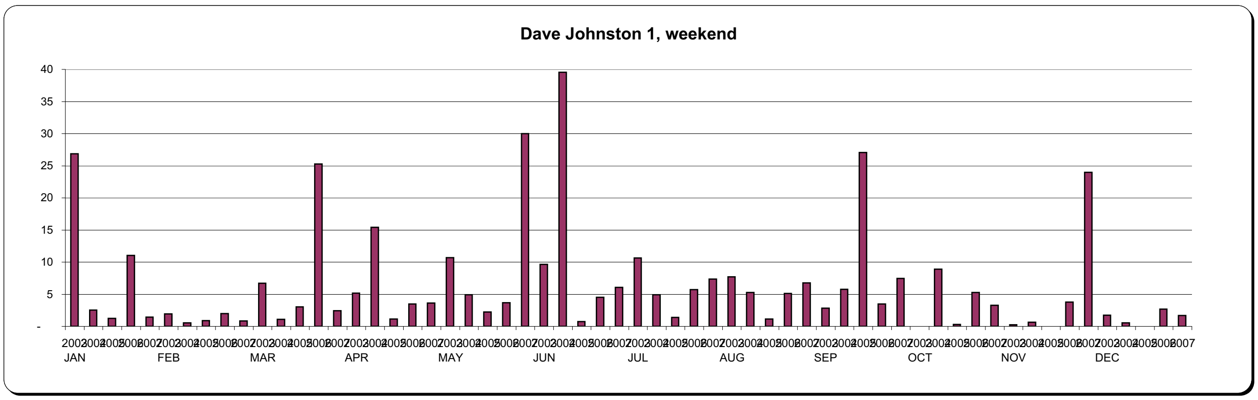


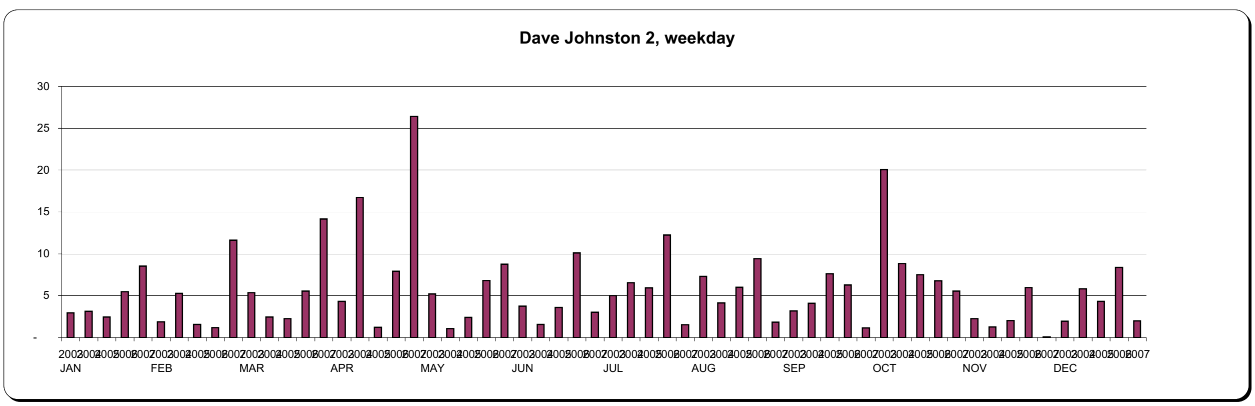


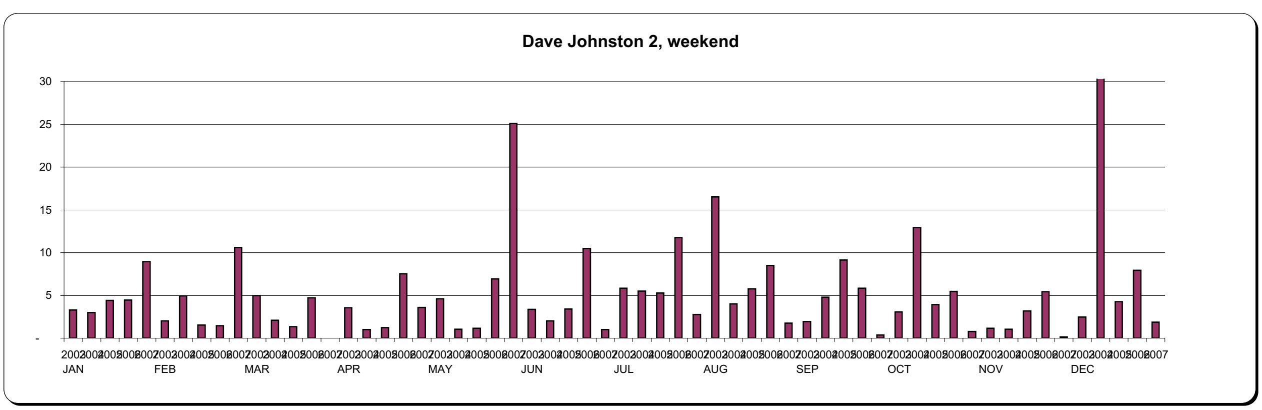


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

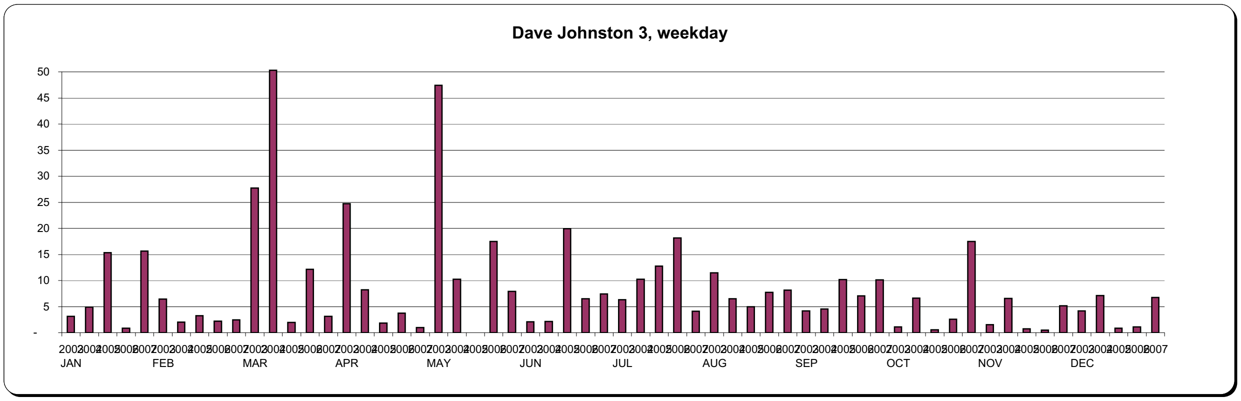


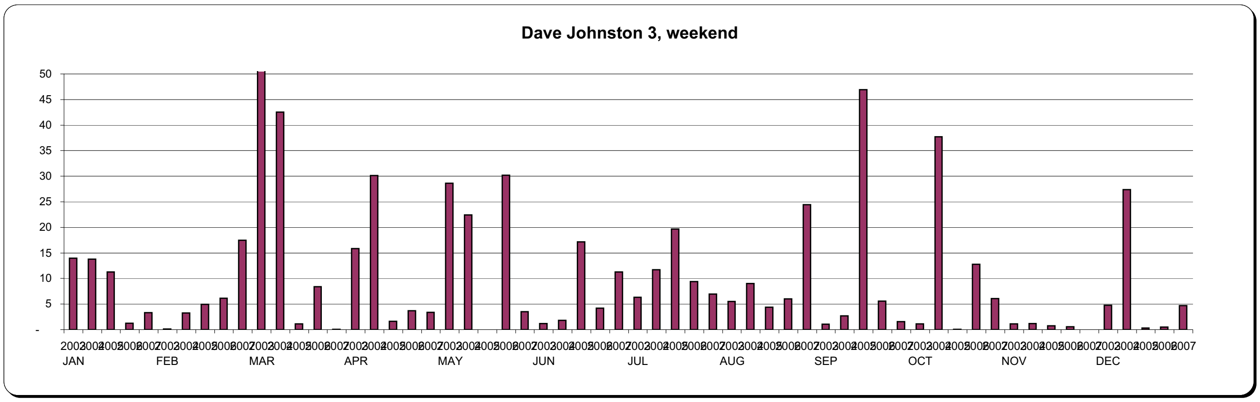


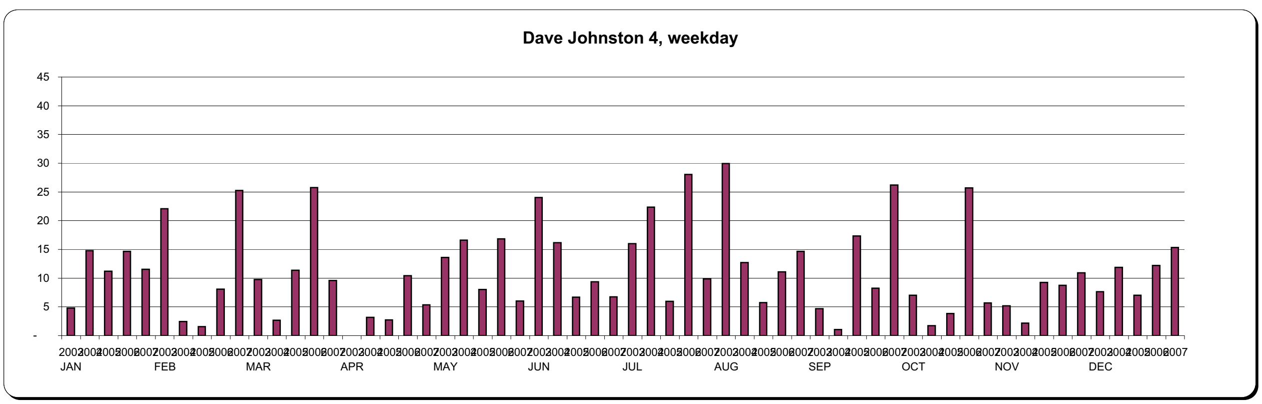


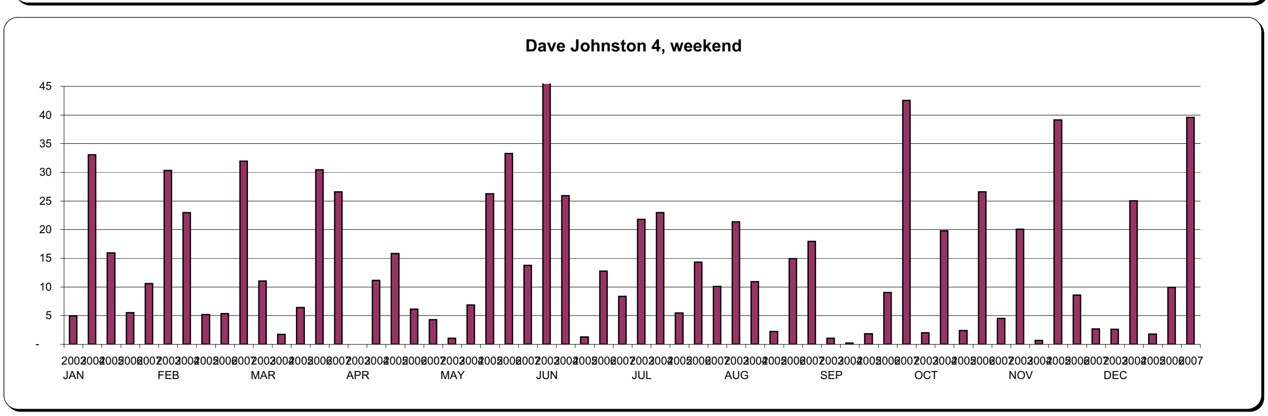


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

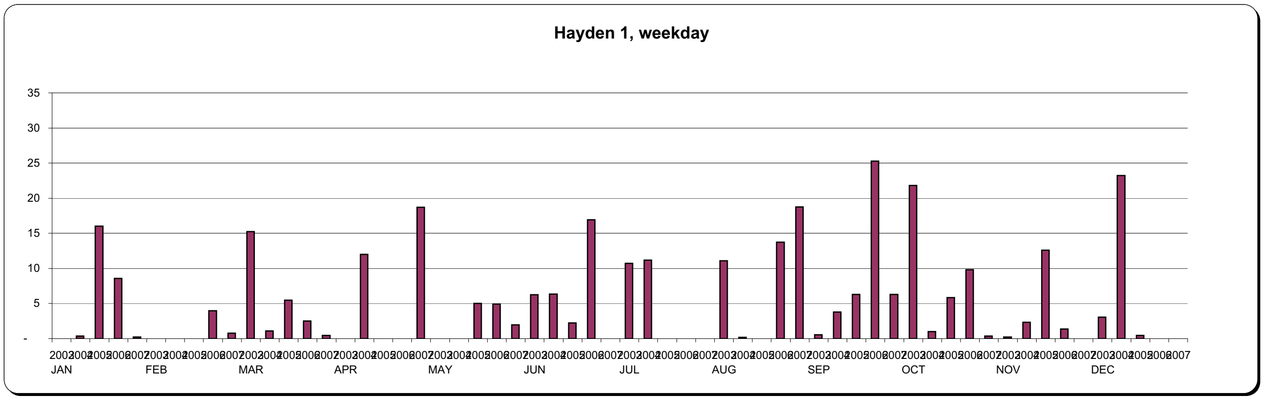


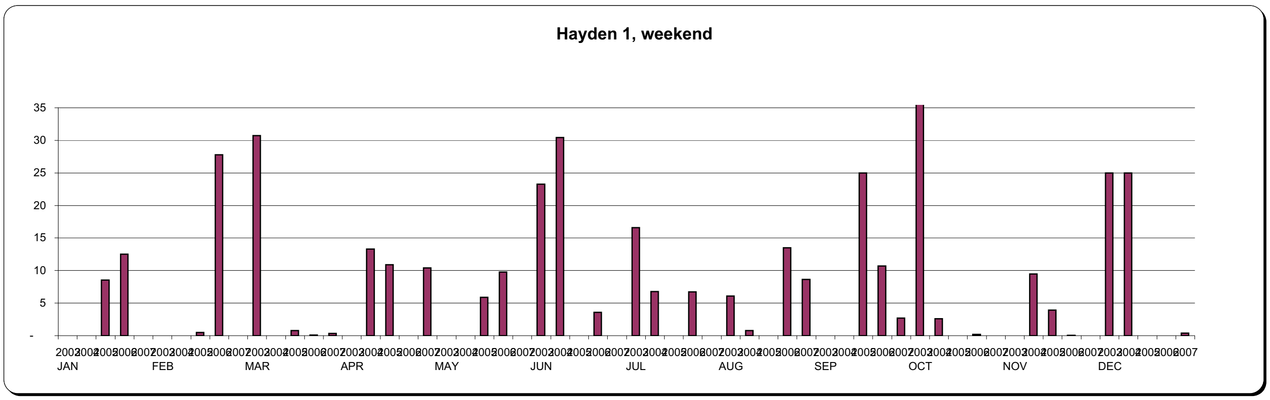


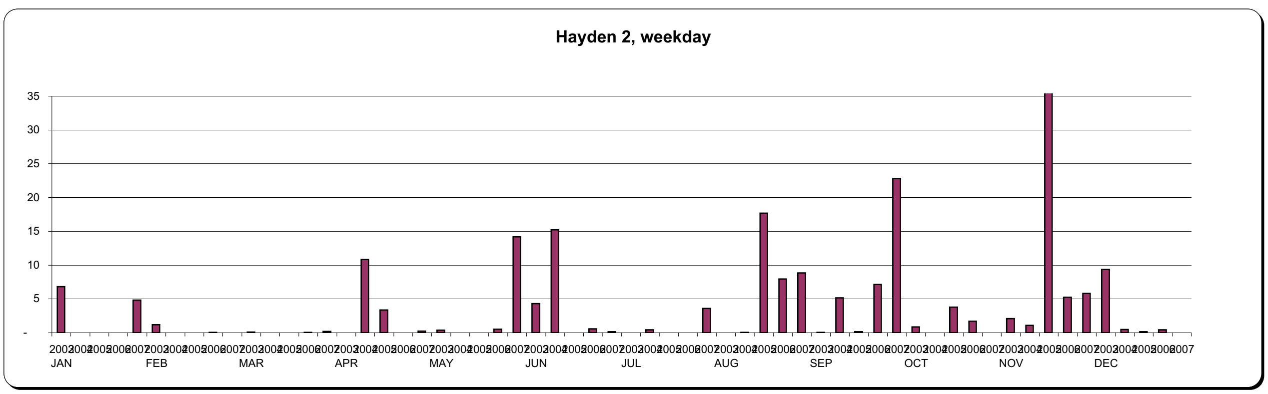


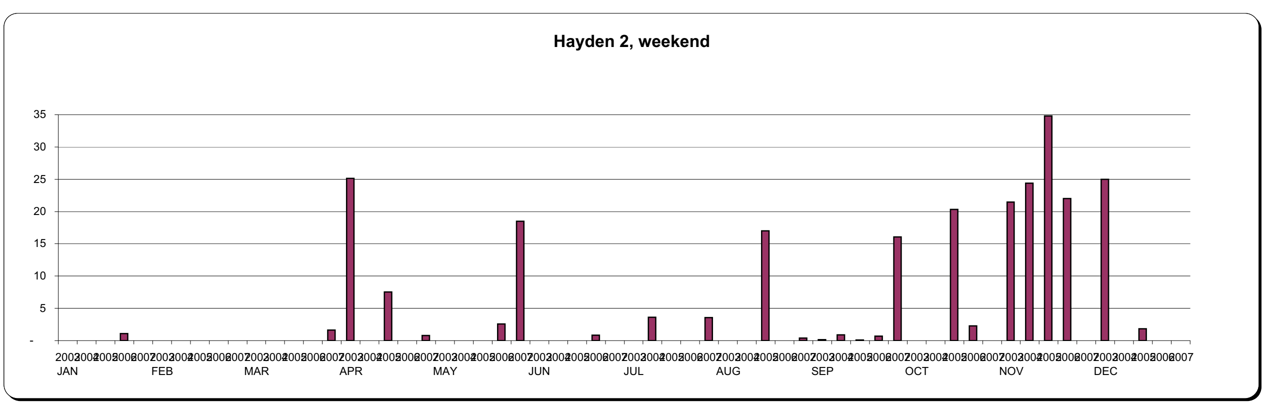


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

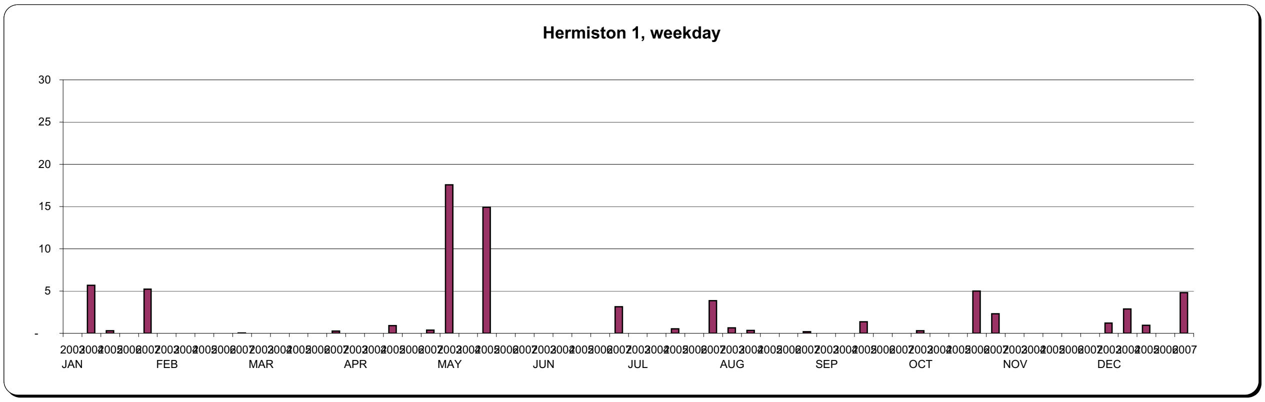


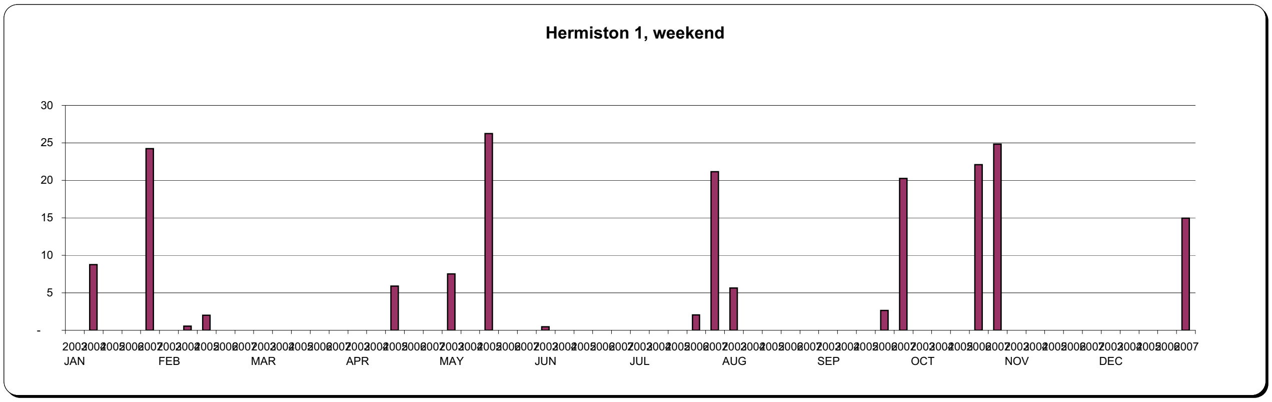


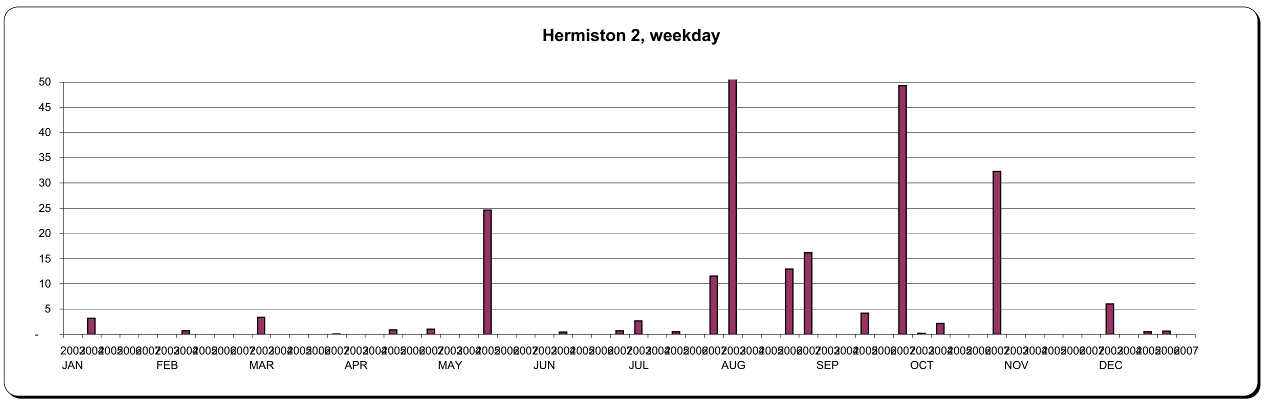


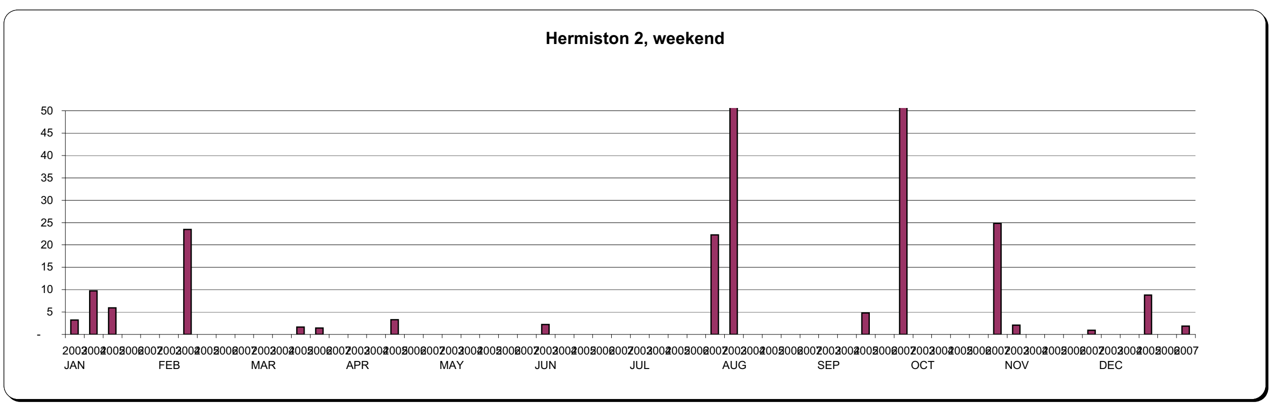


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

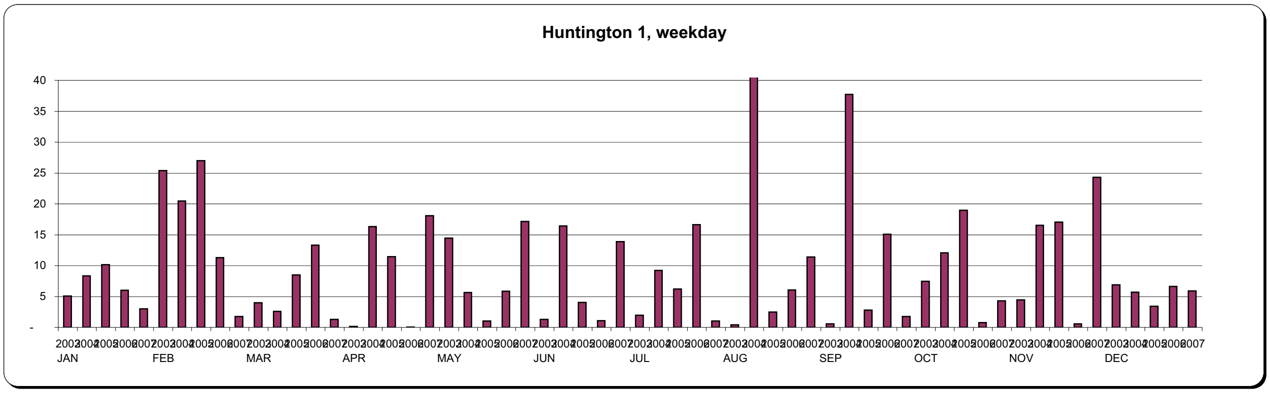


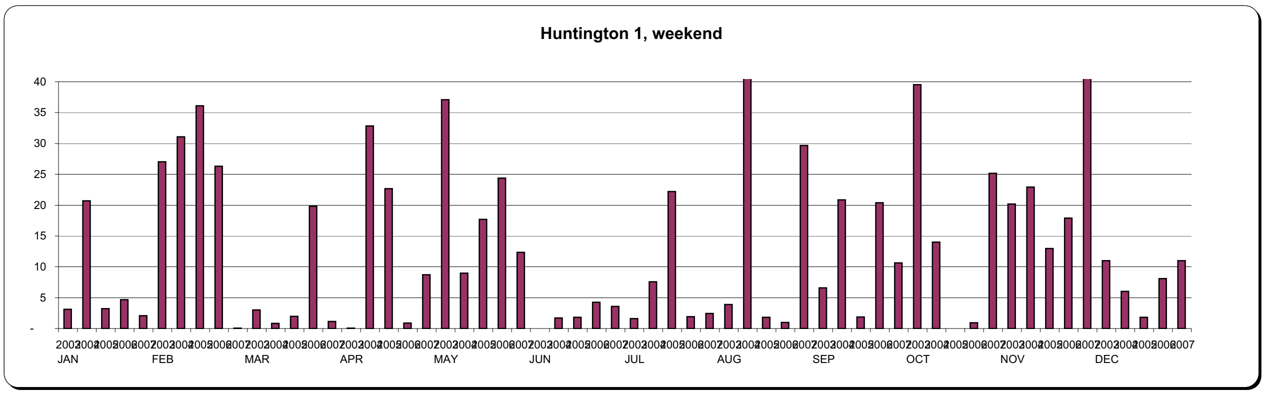


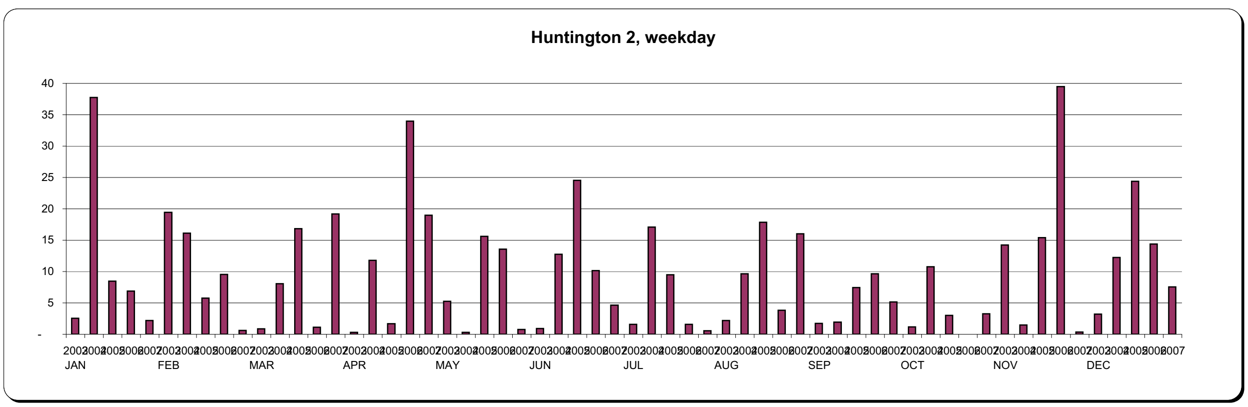


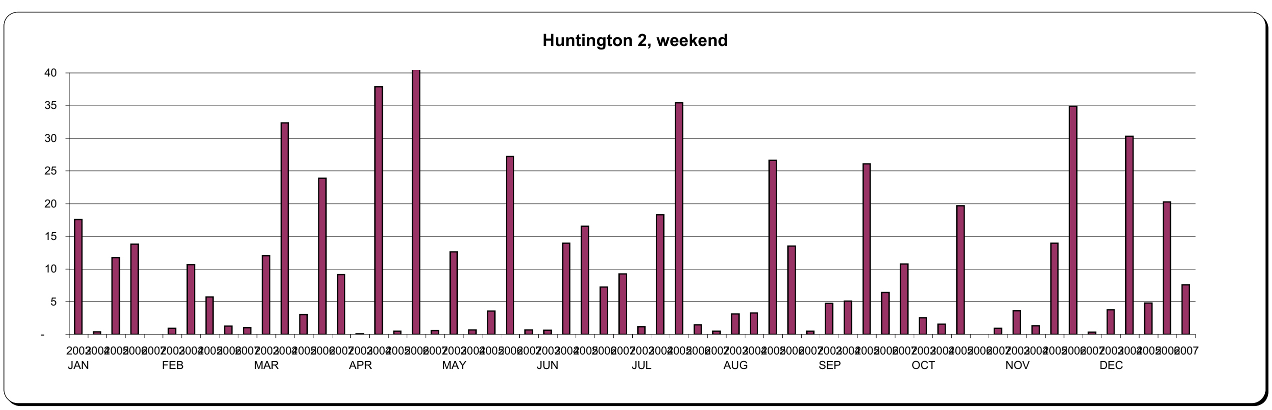


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

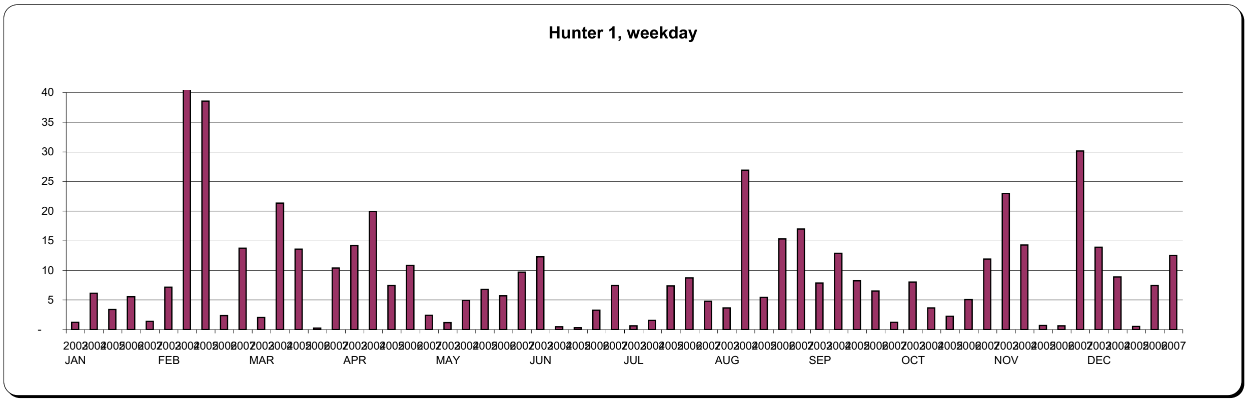


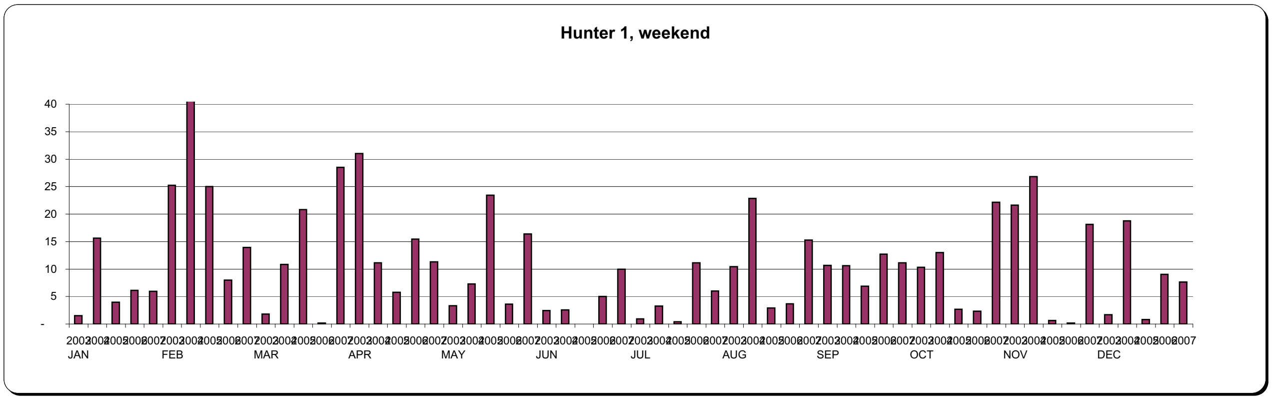


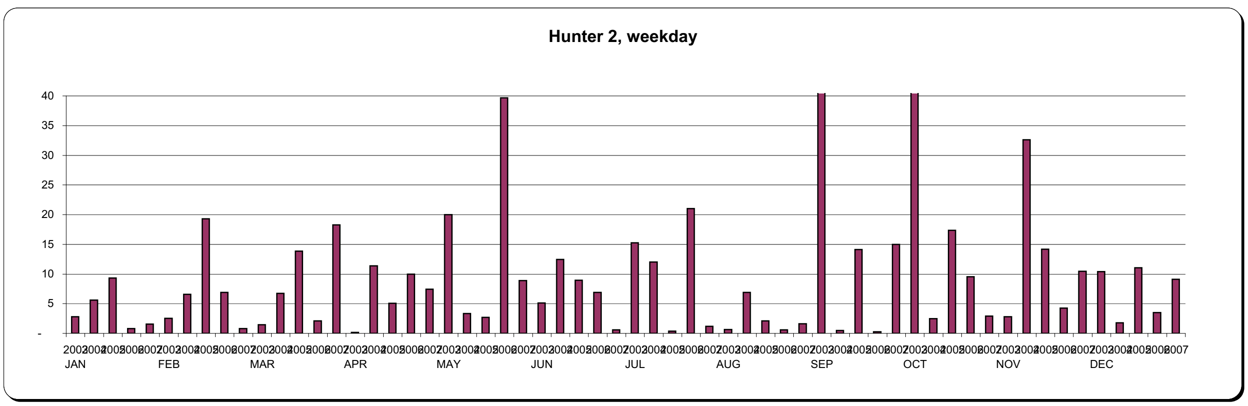


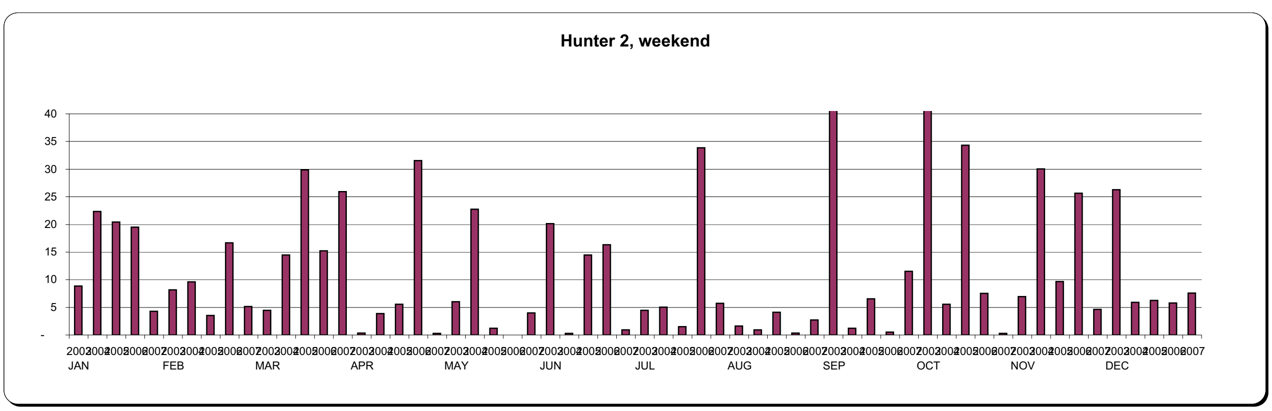


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

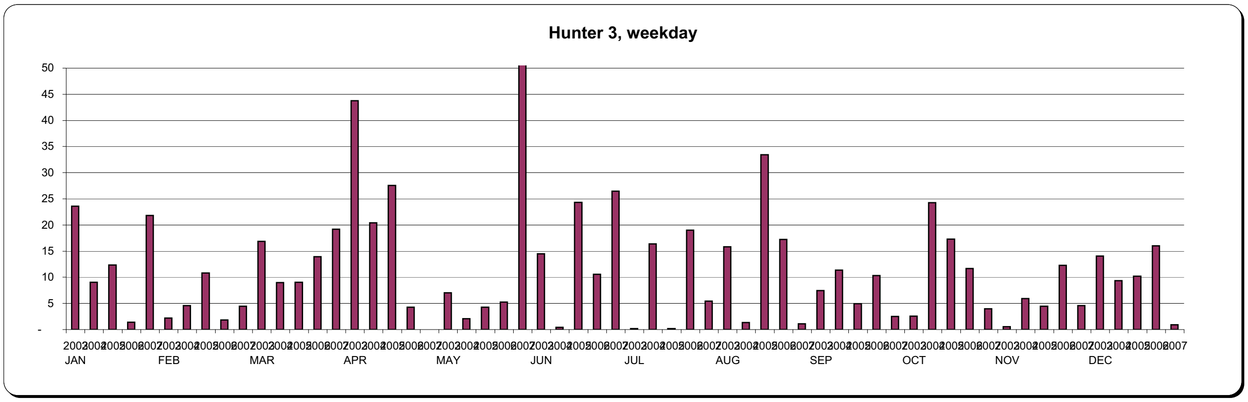


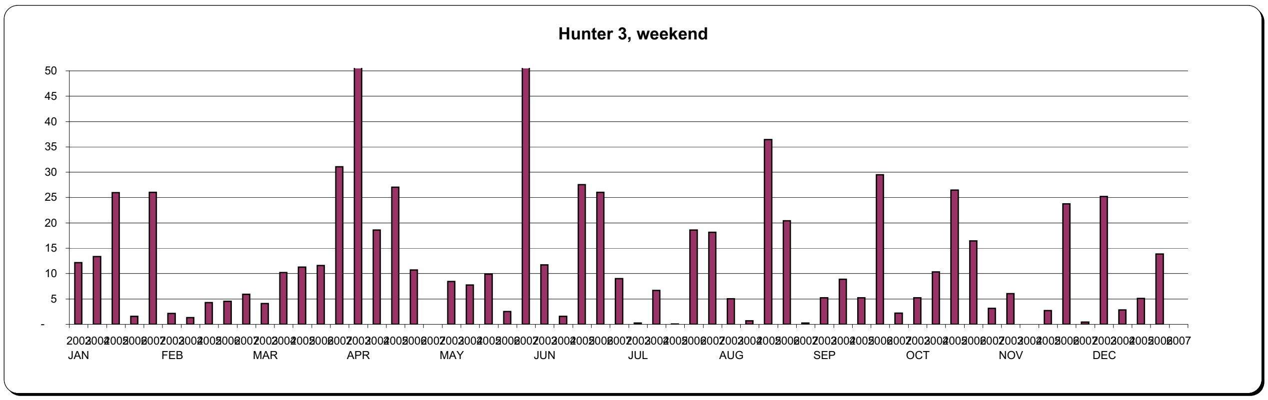


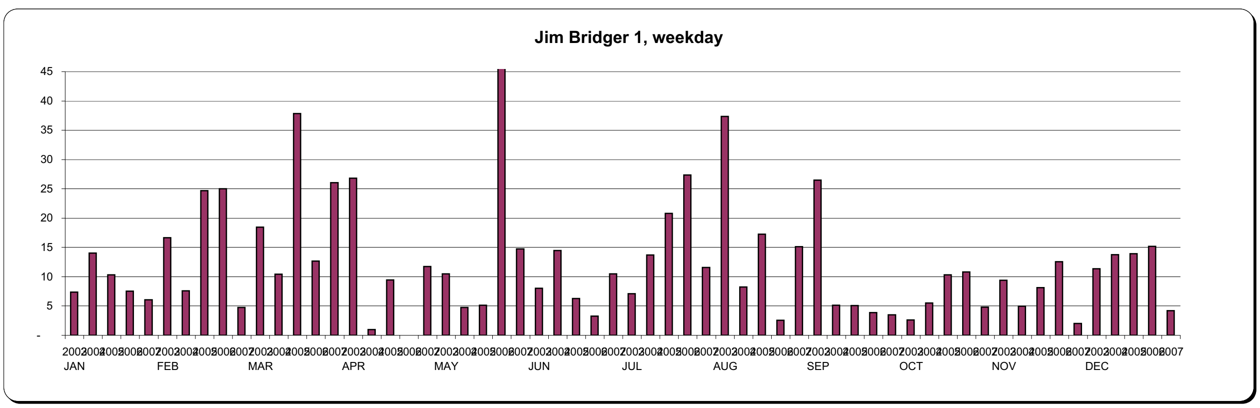


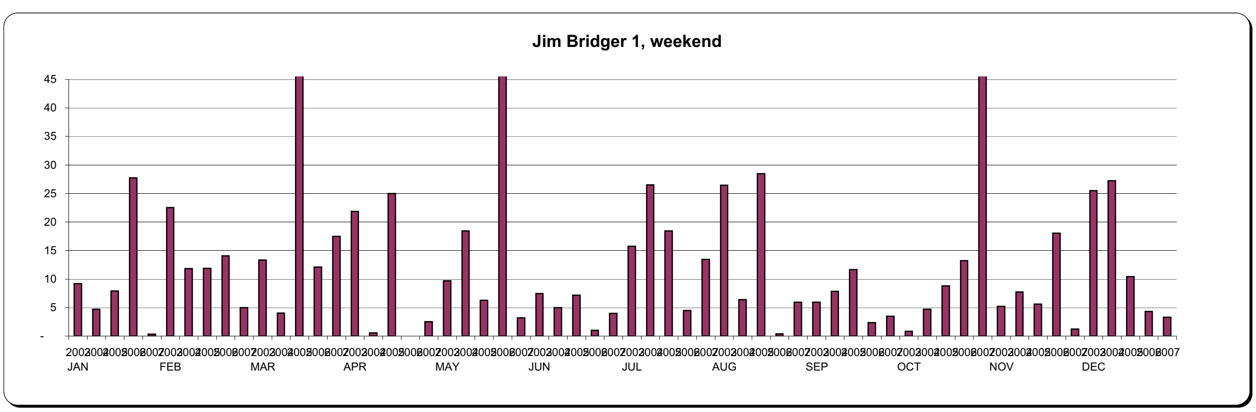


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

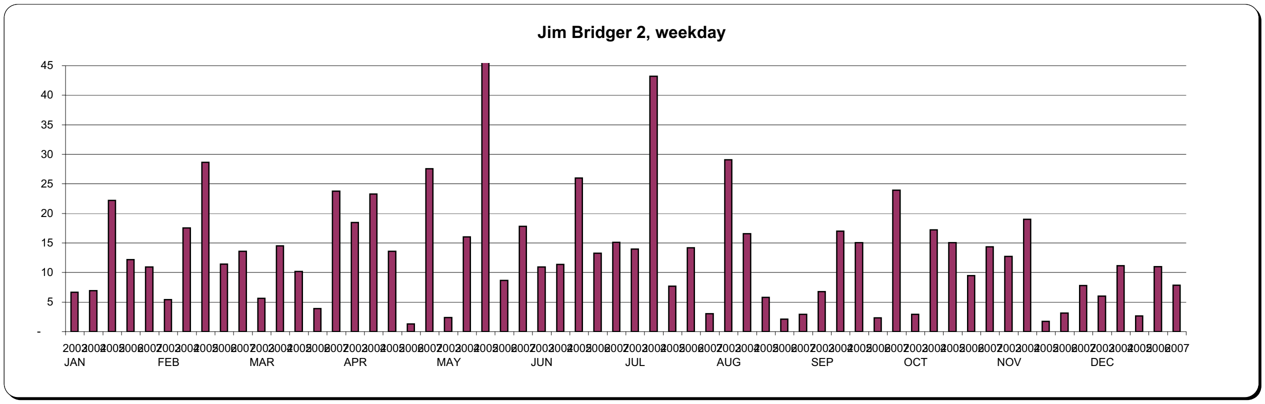


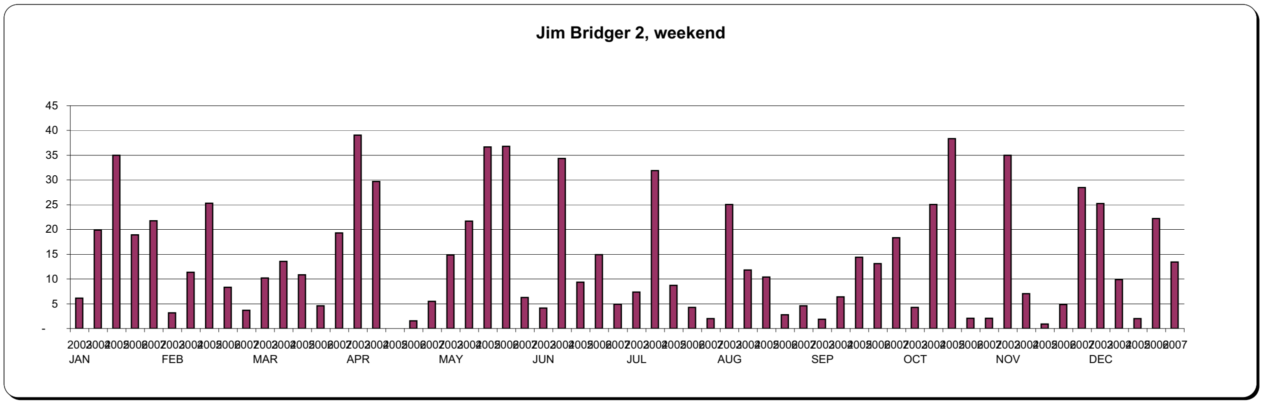


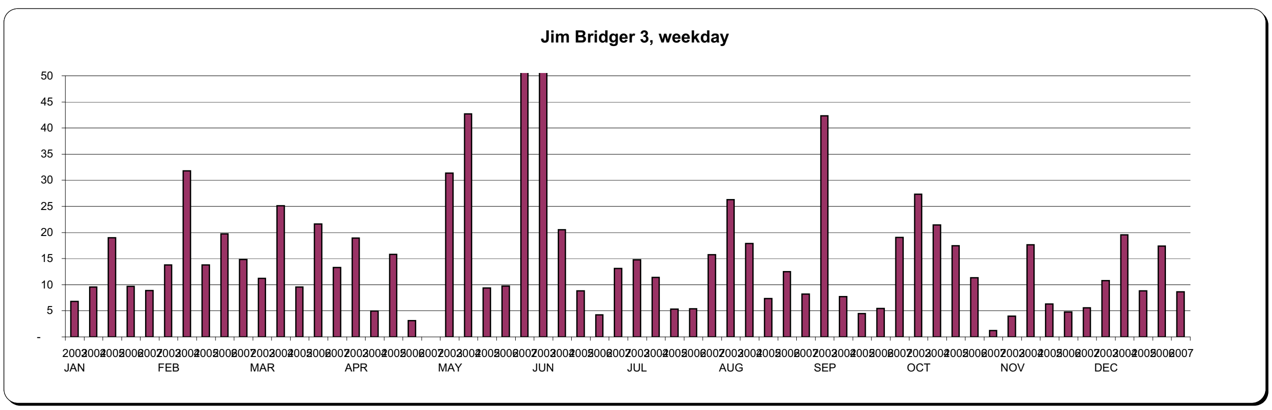


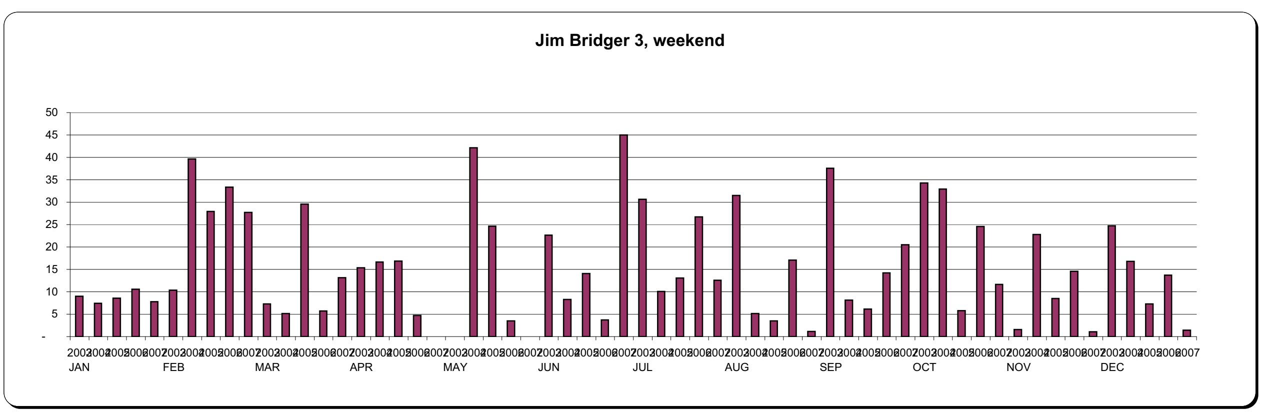


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

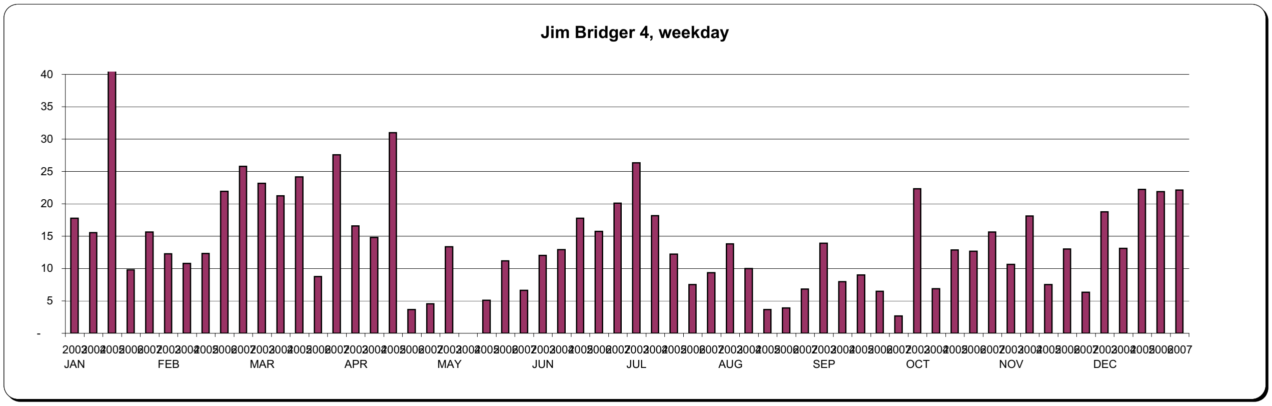


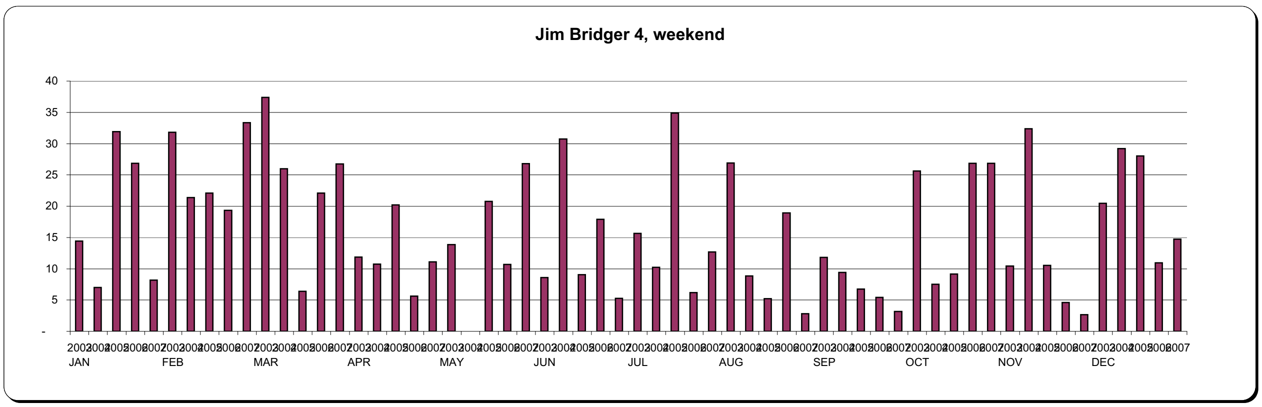


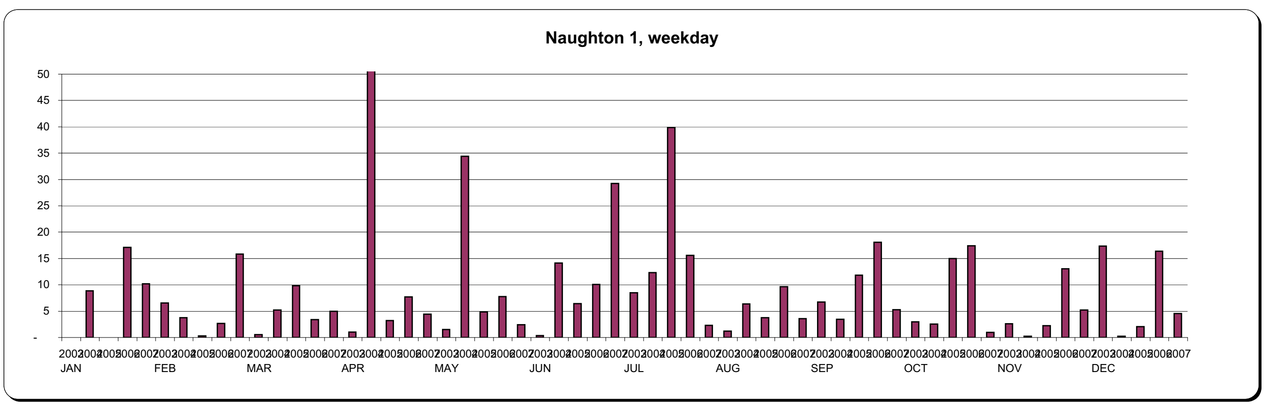


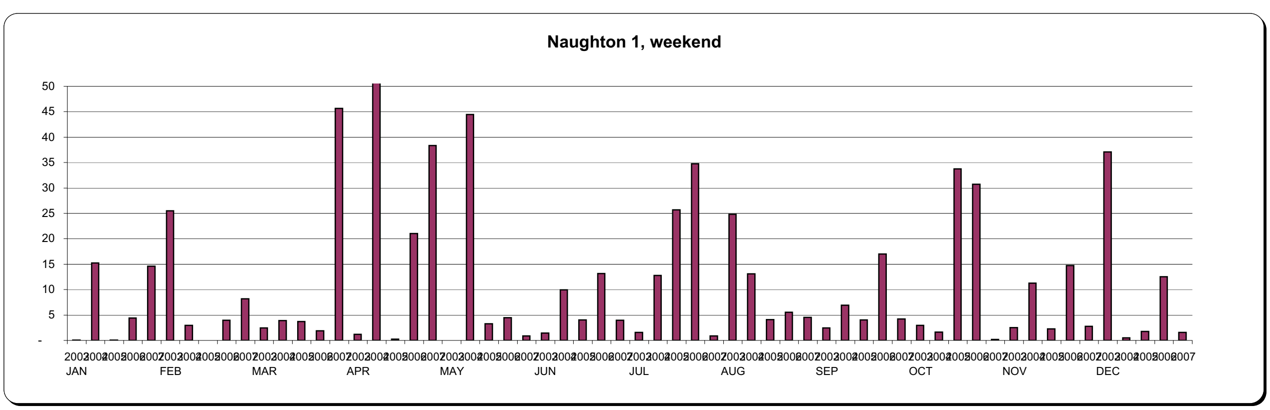


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

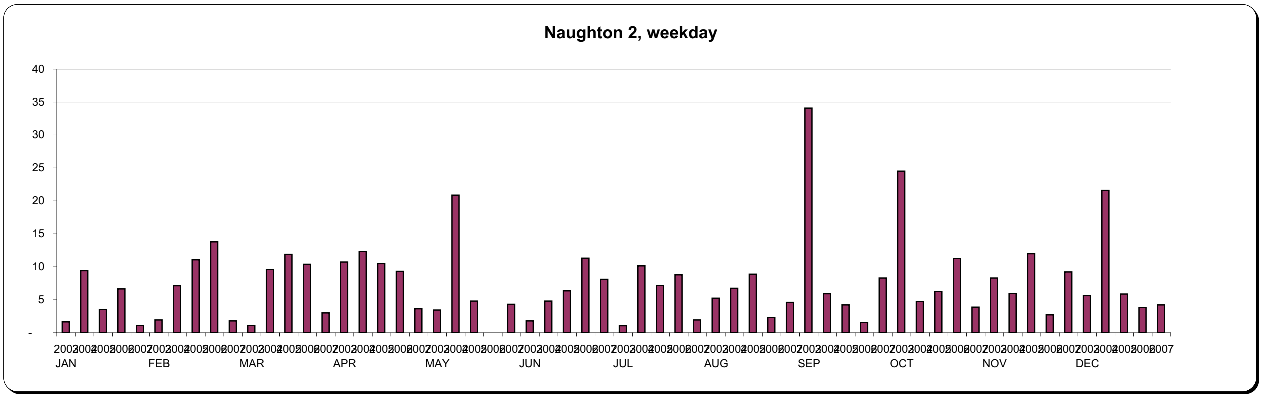


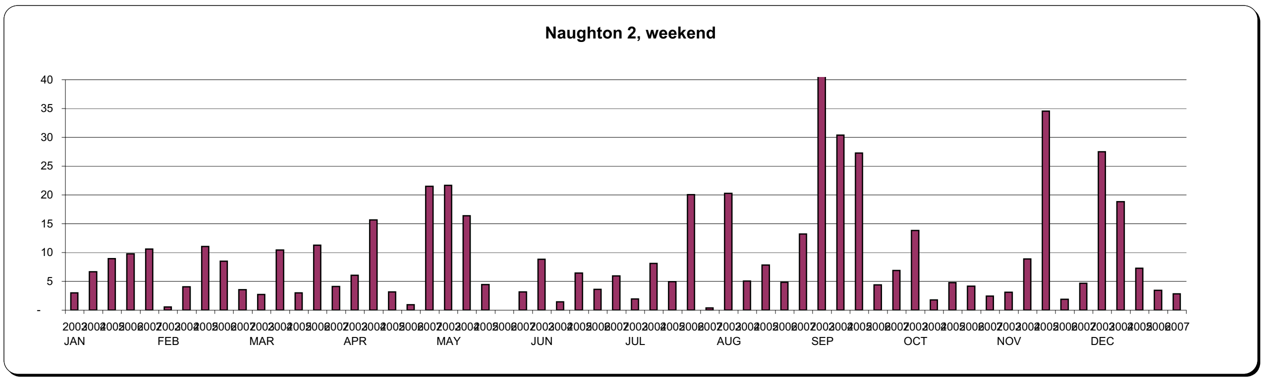


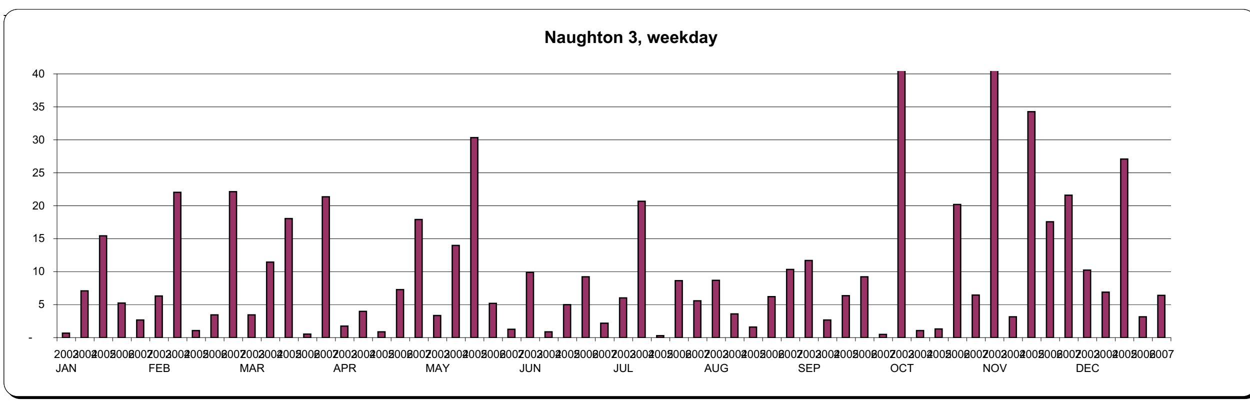


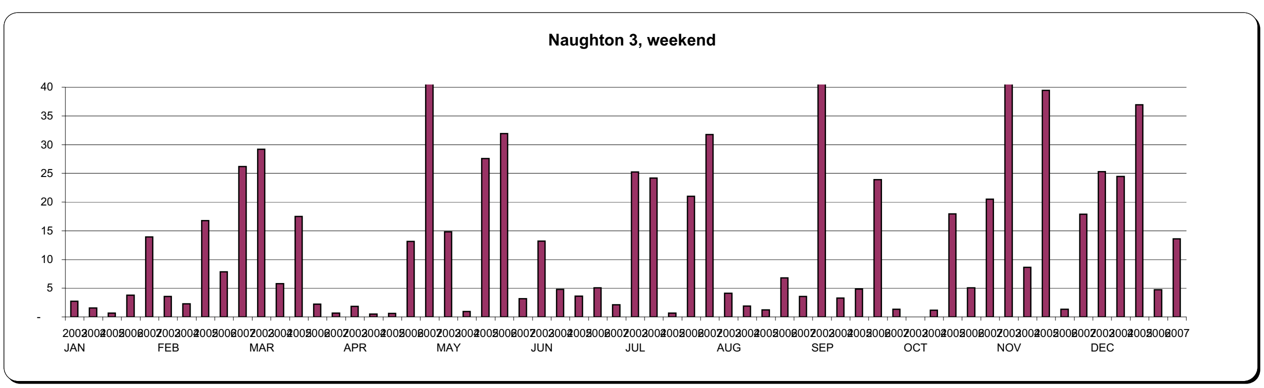


5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month

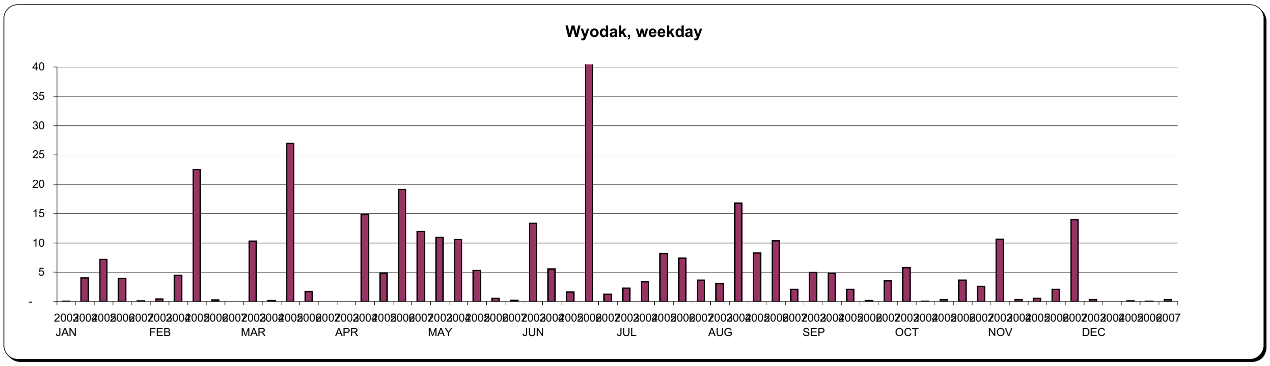








5-year Historical Forced Outage Rates (%), weekday/weekend
by unit, by month



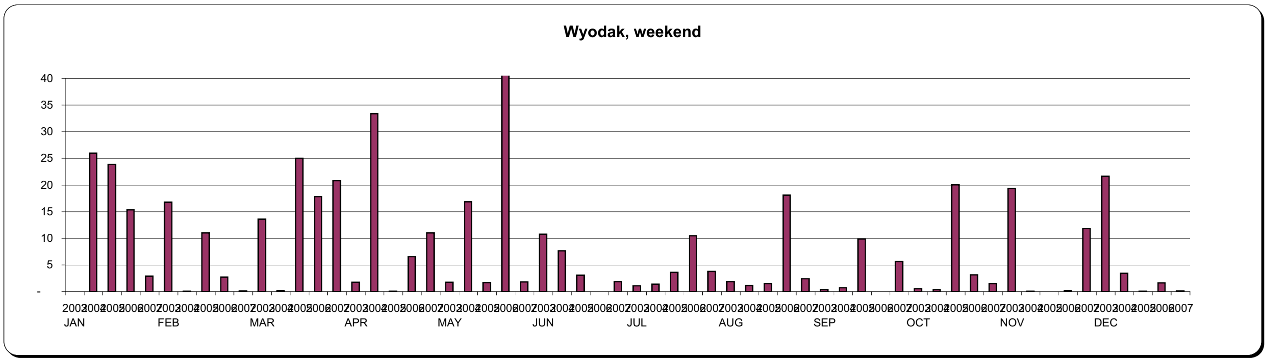


Exhibit PPL/111
Duvall Exhibit

Case UE-199
Exhibit PPL/111
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

ICNU RESPONSES TO DATA REQUESTS

July 2008

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UE 199

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 1.7

Data Request No. 1.7:

See ICNU/100, Falkenberg/30, line 19. Please explain why SMUD and the Black Hills Power sales are the only sales referenced.

Response to Data Request No. 1.7:

Mr. Falkenberg did not review all sales contracts in GRID. Most sales are modeled in the program with pre-specified energy and delivery periods and thus would not fit into the category of contracts discussed in this passage of the testimony. It appears that there are only a handful of call option sales/price shaping sales contracts in GRID: Black Hills, PSCO, SMUD, Sierra Pacific, and UMPA II. Mr. Falkenberg's testimony addresses two of these contracts, but the time limitations imposed by the truncated schedule of the TAM has not allowed ICNU to analyze all such contracts. Should the Company identify any of the call option sales contracts which it believes were unrealistically modeled as compared to actual data, ICNU will certainly consider whether further adjustments, positive or negative, should be made to the GRID model.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UE 199

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 1.9

Data Request No. 1.9:

See ICNU/100, Falkenberg/34, lines 8-11. Please provide all back-up documentation and support for the statement regarding transmission and operating flexibility of Black Hills Power call option.

Response to Data Request No. 1.9:

This is based on discovery obtained in BHP cases over the years, and based on various discussions with the BHP over the period 1990 to 2007. Mr. Falkenberg has not routinely retained these kinds of documents.

Case UE-199
Exhibit PPL/205
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Judith M. Ridenour

July 2008

Q. Are you the same Judith M. Ridenour who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I present the Company's analysis of the Transition Adjustment Mechanism ("TAM") revision to revenues related to sales growth proposed by Staff and Industrial Customers of Northwest Utilities ("ICNU").

Revenues for Sales Growth

Q. Does the Company agree with the revision to the TAM for revenues related to sales growth presented by Staff and ICNU?

A. No. As explained in Ms. Andrea L. Kelly's rebuttal testimony, the Company disagrees that this revision to the TAM is appropriate. However, if the Commission decides to implement a sales growth-related revenue revision, there are errors in the calculations by Staff and ICNU which must be corrected.

Q. What errors are found in the calculation as presented by Staff and ICNU?

A. First, the calculation made by Staff and ICNU is based on growth over a two year period, from 2007 to 2009. This is inappropriate. It ignores the fact that net power costs were ordered by the Commission in UE 191 for 2008. Therefore, if such an approach were adopted in this docket, it would be appropriate to reflect growth only from 2008 to 2009.

Second, the calculation does not account for megawatt-hours used by the Klamath irrigation customers served under the Company's Rate Schedule 33.

These customers pay transitional rates in accordance with Order No. 06-172 and do not pay supply service rates on Schedule 200. Megawatt-hours for these customers have been removed from the 2007 megawatt-hours shown in my Exhibit PPL/201. However, the Company's 2008 and 2009 forecasts include these megawatt-hours under the irrigation class. These megawatt-hours must be removed from both the 2008 and 2009 forecasts in order to calculate megawatt-hour sales growth.

Q. Have you prepared an exhibit showing 2008 and 2009 sales forecasts for Oregon?

A. Yes. The 2008 and 2009 sales forecasts by class for Oregon are provided in Exhibit PPL/206. Both forecasts were previously provided to Staff in response to Staff Data Request 14-2. The 2009 forecast was provided to ICNU in response to ICNU Data Request 6.5.

Q. What corrections have you made for the Klamath irrigation megawatt-hours included in the forecast?

A. I calculated the Klamath megawatt-hours included in the 2008 and 2009 forecasts based on the ratio of Klamath MWh to total MWh from the 2007 test period. I then removed the Klamath megawatt-hours from the forecasts to arrive at a forecast without Klamath irrigation. This calculation is shown in the lower portion of Exhibit PPL/206.

Q. What is the forecasted sales growth from 2008 to 2009?

A. As calculated from the forecasts with Klamath irrigation removed, forecasted sales growth from 2008 to 2009 is 49,889 MWh, which is seven percent of the forecasted 2007 to 2009 sales growth included in Staff's and ICNU's calculation.

Q. Have you prepared an exhibit showing the necessary corrections to the calculation proposed by Staff and ICNU?

A. Yes. Exhibit PPL/207 shows the corrected calculation [apply the forecasted sales growth from 2008 to 2009 and exclude Klamath irrigation megawatt-hours].

Q. Please explain Exhibit PPL/207.

A. Lines 1 through 3 of Exhibit PPL/207 show the calculation of forecasted sales growth from 2008 to 2009. Lines 4 and 5 show the calculation of the average per megawatt-hour rate of net power costs in rates from UE 191 based on the 2008 forecast less Klamath MWh. Lines 6 through 8 show the calculation of the corrected revenue revision advocated by Staff and ICNU. The corrected amount is $883,133.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit PPL/206
Ridenour Exhibit

Case UE-199
Exhibit PPL/206
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Judith M. Ridenour

OREGON SALES FORECASTS AND KLAMATH IRRIGATION ADJUSTMENT

July 2008

PACIFIC POWER
STATE OF OREGON
OREGON SALES FORECASTS AND ADJUSTMENT TO REMOVE KLAMATH IRRIGATION ENERGY

ANNUAL SALES FORECASTS BY CLASS

		2008 MWH	2009 MWH	Formula
(1)	Residential	5,504,615	5,500,858	
(2)	Commercial	4,908,735	4,939,486	
(3)	Industrial	3,377,574	3,413,981	
(4)	Public Street Lighting	41,972	43,032	
(5)	Irrigation	286,505	257,548	
(6)	Total	14,119,401	14,154,906	

KLAMATH IRRIGATION MWH

		2007 MWH[1]	2008 MWH	2009 MWH
(7)	Standard Irrigation Schedule 41	108,189	144,184	129,611
(8)	**Klamath Schedule 33**	106,792	**142,321**	**127,937**
(9)	Total Irrigation	214,981	286,505	257,548

[1] 2007 Klamath Irrigation MWH from General Rate Case UE-179.

ANNUAL SALES FORECASTS BY CLASS WITHOUT KLAMATH IRRIGATION

		2008 MWH	2009 MWH	
(10)	Residential	5,504,615	5,500,858	
(11)	Commercial	4,908,735	4,939,486	
(12)	Industrial	3,377,574	3,413,981	
(13)	Public Street Lighting	41,972	43,032	
(14)	**Irrigation**	**144,184**	**129,611**	(5) - (8)
(15)	**Total**	**13,977,080**	**14,026,969**	

Case UE-199
Exhibit PPL/207
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Judith M. Ridenour

CORRECTED REVENUE RELATED TO SALES GROWTH

July 2008

PACIFIC POWER
STATE OF OREGON
CORRECTED REVENUE RELATED TO SALES GROWTH

				Source:
(1)	2009 Oregon retail sales less Schedule 33	14,026,969	MWh	PPL/206, Ridenour/1
(2)	2008 Oregon retail sales less Schedule 33	13,977,080	MWh	PPL/206, Ridenour/1
(3)	2008 to 2009 Sales Growth	49,889	MWh	(1) - (2)
(4)	UE 191 Oregon NVPC	$247,421,525		UE-191 Order 07-446
(5)	UE 191 Oregon NVPC - $/MWh	$17.70	$/MWh	(4) / (2)
(6)	2008 to 2009 Sales Growth	49,889	MWh	(3)
(7)	UE 191 $/MWh	$17.70	$/MWh	(5)
(8)	**Corrected Calculation**	**$883,133**		(6) x (7)

Case UE-199
Exhibit PPL/300
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Andrea L. Kelly

July 2008

Q. Please state your name, business address and present position with the Company.

A. My name is Andrea L. Kelly. My business address is 825 NE Multnomah St., Suite 2000, Portland, OR 97232. I am employed by PacifiCorp as Vice President of Regulation.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I joined PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 to 2005, I led major strategic projects at PacifiCorp including the Multi-State Process ("MSP") and the regulatory approvals for the MidAmerican-PacifiCorp transaction. In March 2006, I was appointed Vice President of Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I was the policy witness in last year's Oregon Transition Adjustment Mechanism ("TAM") filing. I have also appeared as a witness on behalf of PacifiCorp in the states of Oregon, Idaho, Utah, Washington, and Wyoming. In addition, I sponsored testimony in various proceedings as a member of the Washington Commission Staff.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I respond to the recommendations of the Oregon Public Utility Commission Staff ("Staff") and the Industrial Customers of Northwest Utilities ("ICNU") that the Company impute revenues related to projected sales in this stand-alone TAM filing. I also respond to Staff's proposal to include ancillary service revenues and revenues associated Little Mountain steam sales. The Commission should not consider these adjustments because they are outside of the scope of the TAM. Additionally, there are material errors in the calculation of these recommendations.

Q. Does Staff present other recommendations regarding the TAM calculation to which you respond?

A. Yes. Staff proposes that the 2009 TAM include the Chehalis gas plant, which the Company will acquire in September 2008, assuming it has received all necessary regulatory approvals. My testimony sets out the Company's conditional agreement to the addition of the Chehalis plant to the TAM in the November 1 update, assuming the Company has completed its purchase of the plant by that time. The Company's agreement to this proposal is predicated on the establishment of a deferred account to track the fixed and variable costs of Chehalis so that: (1) PacifiCorp may recover the capital and operations and maintenance ("O&M") costs of the plant in rates beginning on January 1, 2009, if the Commission concludes that the plant is prudent; or (2) PacifiCorp may recover decreases in net power costs ("NPC") related to Chehalis reflected in the

2009 TAM if the acquisition of the plant is ultimately found to be imprudent. The Company has attached a draft of this proposed deferred accounting application as Exhibit PPL/301.

Q. Does ICNU present any other recommendations regarding the TAM filing to which you respond?

A. Yes. ICNU has proposed Minimum Filing Requirements for all future TAM and general rate case filings. The procedural requirements for automatic adjustment clause and rate case filings are addressed in the Commission's rules. No party previously has suggested deficiencies in these rules. To the extent that ICNU thinks these rules need to be revised or updated, ICNU should ask the Commission to open a rulemaking and justify the need for such changes. These generic procedural issues are outside the scope of this TAM filing.

Proposal to Include Projected Revenues in the TAM

Q. Please explain the sales-related revenue proposal Staff and ICNU recommend.

A. Staff witness Ms. Kelcey Brown and ICNU witness Mr. Randall J. Falkenberg recommend that the Commission revise the TAM and reduce the Company's request to account for revenues associated with projected growth in customer sales since the Company's last general rate case, UE 179. Both recommend reducing the TAM by approximately $12.6 million on this basis.

Q. Why do you disagree with this recommendation?

A. The proposed revision is an improper, retroactive change to the scope of the TAM in the middle of a TAM proceeding. The Company filed its first stand-alone

TAM filing outside of a rate case in UE 191. The Company interpreted the scope of the TAM narrowly and consistently with the mechanism adopted in UE 170, a position supported by the other parties and by the Commission in its final decision.

Q. Please explain in more detail how the Company calculated its proposed rates in this case.

A. First, the Company calculated the revenue requirement increase by comparing the NPC approved in the last case with the forecasted NPC in this case. Next, the Company spread the revenue increase to its rate schedules based on present Schedule 200 revenue. The present Schedule 200 revenue in this case is the Schedule 200 revenue approved in UE 191. The proposed revenue increase is then divided by the kilowatt-hours ("kWh") for each schedule to calculate a per kWh rate for each schedule, which are the kWh rates shown in Ms. Judith M. Ridenour's Exhibit PPL/201. These rates are added to the existing Schedule 200 rates to create the proposed new Schedule 200 rates shown in Ms. Ridenour's Exhibit PPL/202.

Q. How do Staff and ICNU propose to change the rate calculation in this case?

A. Staff and ICNU propose that the increase to NPC be offset by an imputed increase to "NPC revenues," which have been derived by Staff and ICNU for the first time in this proceeding.

Q. How do Staff and ICNU derive the NPC revenue offset?

A. Staff and ICNU calculate the increase in forecasted kWh sales over a two-year period – from 2007 to 2009 – and multiply the increase in kWh sales by the 2009 net power costs expressed on a cents per kWh basis. Staff and ICNU then propose to reduce the amount of the TAM increase by the derived revenue increase.

Q. Please describe the limited scope of the TAM.

A. If the TAM is filed outside a general rate case, the Company updates NPC for only the following factors: (1) forward price curve; (2) forecast loads; (3) normalized hydro generation; (4) forecast fuel prices; (5) contract updates; (6) heat rates, planned outages, and de-rates; (7) wheeling expenses; (8) new resource acquisitions; and (9) state allocation factors. Post-filing updates are made in categories (1), (4), (5), (7) and (8) only. Staff and intervenor adjustments are necessarily limited by the narrow scope of the filing. Notably, an update for projected revenues does not relate to components of NPC or fall into the categories above.

Q. Are the distinctions between NPC and sales highlighted by the Federal Energy Regulatory Commission ("FERC") accounts in which these items are tracked?

A. Yes. The NPC accounts are: 447 - Sales for Resale; 555 - Purchased Power; 565 - Wheeling Expense; 501 - Fuel; and 547 - Fuel. The Revenue accounts are: 440 - Residential; 442 - Commercial, Industrial & Irrigation; and 444 - Street & Highway Lighting.

Q. If parties want the Commission to consider material changes to the scope of the TAM, such as the inclusion of projected sales, how and when should they properly make such proposals?

A. Parties should propose forward-looking changes to the TAM in a general rate case, given the broader scope and longer schedule of the filing. Alternatively, a party could request that the Commission open a separate docket on this issue. In either case, changes can be reviewed from a policy perspective, rather than litigated through one-off proposed adjustments. A change of this magnitude to the TAM during the TAM proceeding is unfair to the Company, which has honored the scope of the TAM and made decisions with respect to its 2008 regulatory filings based on the adopted scope of the TAM as implemented in UE 191. Regulatory mechanisms like the TAM provide an incentive for a utility to control costs unrelated to NPC and minimize the number of general rate case filings. If the mechanism is revised on an ad-hoc basis to the utility's disadvantage, this incentive is destroyed.

Q. If PacifiCorp had understood that parties would propose substantive changes to the TAM in this case, would it have filed a general rate case this year instead of a stand-alone TAM filing?

A. Yes. The change to the TAM proposed by Staff and ICNU would result in a reduction to forecasted return on equity of over 50 basis points or one-half of one percent. The decision to file a stand alone TAM this year instead of a general rate case was a close one, primarily because of the ongoing lack of recovery of the capital and O&M costs of the Lake Side gas plant in Oregon rates, as well as industry-wide upward cost pressures. In the TAM update, Lake Side reduces system NPC by approximately $110 million. At the same time, Lake Side would increase system revenue requirement by approximately $55 million. The financial impact of this mismatch in cost recovery associated with the narrow scope of the TAM eclipses the alleged mismatch associated with loads and revenues Staff and ICNU complain of in this case.

Q. If the Commission accepts the argument that the TAM should be updated for projected sales to avoid a mismatch in treatment of load growth, in fairness, should the Commission also take steps to mitigate the mismatch now associated with the manner in which Lake Side is reflected in Oregon rates?

A. Yes. Attached to my testimony as Exhibit PPL/302 is a proposed request for deferred accounting for the capital and O&M costs of Lake Side. If the Commission directs the Company to update projected sales for the 2009 TAM, fairness requires that the Commission also permit the Company to receive deferred accounting to capture the capital and O&M costs of the Lake Side plant at the commencement of the 2009 TAM. PacifiCorp's agreement to include variable costs of new generation facilities in the TAM has always been predicated on expeditious recovery of the associated capital and O&M costs. There is no justification for changing the TAM to address one cost recovery mismatch while at the same time allowing continuation of a larger mismatch.

Q. Are there other mismatches in this case that work against the Company?

A. Yes. As explained in Mr. Gregory N. Duvall's testimony, the Company has agreed to address ICNU's commitment logic adjustment by applying nightly screens in the GRID model to certain gas units. These screens result in the need for daily unit start-ups, which increases fuel and O&M costs. These costs offset the decrease in NPC associated with the nightly screens. ICNU contends that the O&M costs are not recoverable in the TAM. The Company has agreed not to seek the O&M offset in this case, assuming the Commission adheres to its historic narrow interpretation of the TAM. If the Commission accepts the Staff and ICNU revision to the TAM for projected revenues, however, the Commission should also allow the Company to recover the O&M cost offset for implementation of the nightly screens.

Q. Does the Company intend to file a general rate case in 2009?

A. Yes. Next year, the Company plans to file its 2010 TAM within a general rate case. The Company is willing to meet with parties in advance of the filing to discuss potential changes to the scope of the TAM which could be addressed in that case, including the possibility of using forecasted sales to update present revenues in future stand-alone TAM filings.

Q. How do Staff and ICNU defend their proposal to make such a significant revision to the TAM?

A. The only justification appears to be that a revenue adjustment is included as part of annual power cost updates for Portland General Electric ("PGE") and Idaho Power. In a data request, the Company requested that Staff provide all citations to prior TAM cases that support the basis for this adjustment; Staff could not provide any such citations. Exhibit PPL/303.

Q. If PGE and Idaho Power make this adjustment in their annual power cost updates, why shouldn't PacifiCorp do the same?

A. The underlying mechanisms differ significantly among the utilities. The current annual power cost updates for both PGE and Idaho Power are integrated into a larger power cost adjustment mechanism ("PCAM") where different design considerations apply. Of import, PacifiCorp does not have a PCAM and bears the risk of differences between forecasted NPC and actual NPC. PGE's Resource Valuation Mechanism ("RVM") mechanism was originally designed to function with a PCAM. However, even during the years that the RVM functioned without a PCAM, PGE made post-filing updates to account for changes in loads, something that has never been a part of PacifiCorp's TAM. Idaho Power's annual update also allows it to make post-filing updates for material changes in loads and hydro generation. In summary, it is unreasonable to suggest that PacifiCorp's TAM should conform to the power cost recovery mechanisms of PGE and Idaho Power in one specific aspect, given the many significant differences that exist between those mechanisms and the TAM. If uniformity among all utilities is the Staff's and ICNU's goal, a rulemaking may be a more appropriate vehicle for the Commission to address these issues.

Q. Will PacifiCorp over-collect its authorized level of NPC if it does not make this adjustment?

A. No. PacifiCorp's ability to recover its costs in totality is the appropriate metric, rather than a focus on one sub-set of costs. In addition, Schedule 200 is designed to recover all generation-related costs, not just NPC. Furthermore, the parties present no evidence that the current TAM without a sales growth offset results in over-collection. Indeed, the evidence for 2008 indicates quite the opposite effect. The 2008 TAM was based upon NPC of $980 million. As noted in Mr. Duvall's testimony, actual NPC for the 12 months ended May 2008 was approximately $1.055 billion. Given these numbers, there is no danger that the Company will over-collect NPC in rates in 2008. Similar rising-cost market conditions are forecast for 2009. Given the sharp increases projected in NPC, the Staff and ICNU adjustment is much more likely to perpetuate the Company's under-recovery of NPC, than to prevent its over-recovery of NPC. The TAM places significant risks on PacifiCorp related to the difference between forecasted NPC and actual NPC; this risk would be exacerbated by the adoption of the TAM revision proposed by Staff and ICNU outside of a comprehensive review of all elements of the TAM.

Q. Are there material mistakes in the calculation of the impact of the Staff and ICNU revision to the TAM?

A. Yes. As explained in the rebuttal testimony of Ms. Ridenour, Staff and ICNU fail to account for loads associated with Klamath irrigation customers served under discounted rates. The proposed TAM revision also reduces this filing by revenue growth for two years rather than one year. I am informed that this constitutes an illegal collateral attack on rates set in UE 191. If the adjustment is calculated correctly and applied prospectively for projected sales growth from 2008 to 2009, the impact of the Staff and ICNU revision to the TAM, amounts to approximately $883,000, as shown in Exhibit PPL/207.

Staff's "Other Revenues" Adjustment

Q. Please explain Staff's "Other Revenues" adjustment.

A. Staff proposes to reduce the Company's TAM by revenues for ancillary services ($524,595 Oregon allocated) and steam sales associated with the Little Mountain gas facility ($623,477 Oregon allocated).

Q. Why do you disagree with these adjustments?

A. Staff's "Other Revenue" adjustments present many of the same concerns as the proposed TAM revision for projected revenues discussed above. The scope of the TAM has never included "Other Revenues." In UE 191, the Commission agreed with PacifiCorp that ICNU's proposed adjustment to "Other Revenues" to account for offsets to the GP Camas contract was "outside of the scope of the TAM proceeding." The Commission stated that: "We did not intend that the TAM procedure would encompass such factors as contract 'offsets' that are better suited to the general rate case…" Order No. 07-466 at 22.

Q. Staff claims that the UE 191 decision is distinguishable because it relates to "Other Revenues" associated with fixed rather than variable power costs. Please comment.

A. There is nothing in the history of the TAM that supports this distinction. In any event, Staff has not made clear why "Other Revenues" associated with ancillary services and steam sales are more closely tied to variable than fixed costs.

Q. Staff bases its ancillary services adjustment on the UE 180 Order involving PGE. Is this appropriate?

A. No. The UE 180 case was a general rate case, so it does not provide precedent for including "Other Revenues" in a stand-alone annual power cost update. Staff also admits that PGE now tracks ancillary services revenues through its PCAM, further demonstrating the inapplicability of this precedent to PacifiCorp.

Q. Are there problems in the calculation of the Staff adjustments that highlight the difficulty of making such adjustments outside of a general rate case?

A. Yes. Ms. Brown is attempting to update two small portions of Account 456 – Other Electric Revenues from what is presently recovered in base revenue requirement. However, the Company's last general rate case, which was settled in an all-party Stipulation, did not set a base revenue requirement level for this account. The Stipulation specifies that one of the changes from the original revenue requirement requested by the Company is an increase in other electric revenues, but the magnitude of the increase is not specified. As shown in PacifiCorp's original filing in UE 179, $5,667,037 of Little Mountain steam revenues (Exhibit PPL/901, page 3.7) were included in the requested revenue requirement. Ancillary services revenues were included in Account 456, but not called out as a specific line item amount.

Q. What are the specific errors with the calculation?

A. Ms. Brown proposes an update to Little Mountain steam revenues based upon actual 2007 steam sales and estimated 2009 test year sales based "on GRID model output." There are two problems with this approach. First, Staff's adjustment is based on actual 2007 steam sales ($4.3 million) rather than the steam revenues presently in base revenue requirement. The best estimate for steam revenues in rates is at least the $5.7 million the Company requested in UE 179, since the UE 179 Stipulation was predicated on an **increase** (and not any disallowance) in Other Revenues filed in that case.

Second, as described in Exhibit Staff/104, the amounts for 2009 are planned amounts, not those estimated on GRID model output. Consistent with the Little Mountain cost update included in this filing, the Company estimates the level of Little Mountain steam revenue for 2009 to be $6,502,581 million. As such, Ms. Brown's adjustment would be reduced to $832,000 on a system basis ($6.50 million less $5.67 million), or $220,000, Oregon allocated, an immaterial amount to warrant a change to the TAM.

Q. Can Ms. Brown's ancillary services adjustment be accurately calculated?

A. No. If an adjustment were to be made to ancillary service revenues, it also should be based on ancillary service revenues presently in base revenue requirement from UE 179. However, the level of ancillary service revenues was not part of the record in UE 179.

Q. Does the Company have data on actual ancillary service revenues?

A. Yes. The amount of ancillary service revenue received by its Merchant Function in 2007 was $7,988,505 as shown on Exhibit Staff/103, page 2. The Company's 2009 forecasted ancillary service revenues are $5,986,723, which is less than its 2007 level. This suggests that an adjustment for ancillary service revenues would increase revenue requirement in this case, undermining any basis for Staff's proposed adjustment.

Chehalis

Q. Staff proposes including the Chehalis plant in the TAM. Can you respond?

A. The Company hopes to close on its purchase of the Chehalis plant in September 2008. Assuming the Company has completed its purchase of the plant by November 1, the Company could include the plant in the 2009 TAM. Consistent with the application of the matching principle, the Company's willingness to agree to include the plant in the TAM is conditioned on the Company's ability to receive contemporaneous recovery of the non-net power cost elements of the Chehalis plant.

Q. Are there other concerns with respect to reflecting the Chehalis plant in the TAM?

A. The Chehalis plant cannot be reflected in rates without a determination that the resource is prudent. The Company is not willing to reflect NPC decreases associated with the plant, only to have the capital cost recovery later disallowed on the basis of prudence.

Q. How can the Commission address these concerns?

A. The Commission could allow establishment of a deferred account to track the fixed and variable costs of Chehalis so that: (1) PacifiCorp may recover the capital and O&M costs of the plant in rates beginning on January 1, 2009, if the Commission concludes that the plant is prudent; or (2) PacifiCorp may recover the Chehalis-related NPC decreases reflected in the 2009 TAM if the plant is ultimately excluded from rate base as imprudent. The Company's agreement to include Chehalis in the November 1 update is predicated on the approval of the draft deferred accounting application attached as Exhibit PPL/301.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Case UE-199
Exhibit PPL/301
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Andrea L. Kelly

DRAFT APPLICATION FOR DEFERRED ACCOUNTING FOR CHEHALIS

July 2008

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM _____

In the Matter of the Application of PACIFICORP, dba PACIFIC POWER for a Deferred Accounting Order for Costs Associated with the Chehalis Generating Plant.	**APPLICATION FOR DEFERRED ACCOUNTING**

I. INTRODUCTION

Under ORS 757.259 and OAR 860-027-0300, PacifiCorp (the "Company") requests that the Public Utility Commission of Oregon ("Commission") issue an order authorizing the Company to defer amounts associated with the 520 megawatt natural gas fired combined cycle generating plant in Chehalis, Washington. PacifiCorp requests deferral beginning on January 1, 2009 of (1) the revenue requirement associated with the Chehalis plant that was not included in PacifiCorp's net power costs ("NPC"); and (2) the decreases to NPC that are associated with the Chehalis plant. Depending on the Commission's decision on the prudence of the Chehalis plant in a future proceeding, PacifiCorp seeks these deferrals to either (1) accurately track fixed and operations and maintenance ("O&M") costs associated with Chehalis for later inclusion in rates or (2) accurately track the decrease to NPC that result from Chehalis to recover these amounts.

II. NOTICE

Communications regarding this application should be addressed to:

Oregon Dockets	Katherine McDowell
PacifiCorp	McDowell & Rackner PC
825 NE Multnomah, Suite 2000	520 SW 6th, Suite 830
Portland, OR 97232	Portland, OR 97204
Telephone: (503) 813-5542	Telephone: (503) 595-3924
Email: oregondockets@pacificorp.com	Email: katherine@mcd-law.com

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

By email (preferred)	datarequest@pacificorp.com
By regular mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232
By facsimile	(503) 813-6060

III. DEFERRAL OF COSTS

The following information is provided pursuant to the requirements set forth in OAR 860-027-0300(3).

A. Description of Utility Expense.

PacifiCorp respectfully requests deferral of fixed costs associated with the Chehalis plant. These costs are not currently included in rates. In the Commission's order on PacifiCorp's most recent Transition Adjustment Mechanism ("TAM"), the Commission ordered that the TAM account for reductions to NPC caused by the Chehalis plant. Chehalis reduced system NPC in the 2009 TAM July update by approximately $_______. At the same time, Chehalis increased system revenue requirement by approximately $_________

Chehalis' impact on the system revenue requirement was not included in the 2009 TAM because of the limited scope of the TAM mechanism. As a result, customers will receive the benefit of the Chehalis plant, in the form of a reduction to the Company's NPC, but will not bear the cost of the plant. The requested deferral will allow PacifiCorp to track the fixed and O&M costs of the plant for later inclusion in rates to rectify this mismatch between costs and benefits.

PacifiCorp also requests deferral of the decrease to NPC in the 2009 TAM resulting from the Commission's inclusion of the Chehalis plant. As discussed in more detail below, PacifiCorp requests deferral of these amounts so that they may be refunded to the Company in the event that the Commission disallows recovery of the Chehalis plant as an imprudent investment.

B. Reasons for Deferral.

This request seeks to match the costs associated with the investment in the Chehalis plant with the benefits of the plant received by Oregon customers. ORS 757.259(2)(e) allows the deferral of utility expenses or revenues where necessary to match appropriately the costs borne by and benefits received by customers.

The Company closed on its purchase of the Chehalis plant in September of 2008. In the 2009 TAM proceeding, the Company objected to including the Chehalis plant in the TAM without receiving expeditious recovery of the fixed costs of the plant.[1] This objection was based on the fact that the Commission had not ruled on the prudence of the Chehalis plant. The Company was concerned that the TAM would include NPC decreases associated with the Chehalis plant, but that the Commission could preclude capital cost recovery of the plant on the basis of prudence in a future proceeding.

To address this concern, PacifiCorp conditionally agreed to include Chehalis in the 2009 TAM if the Commission allowed the Company to establish a deferral account to track both the fixed and O&M costs associated with the Chehalis plant and the decrease to NPC resulting from inclusion of the Chehalis plant in the 2009 TAM. The Company requests deferral of fixed and O&M costs associated with the Chehalis plant in order to reduce the mismatch between customer costs and benefits caused by including Chehalis in the 2009

[1] In its general rate case Docket UE 170, PacifiCorp originally objected to including variable costs of new generation facilities in the TAM. *Re PacifiCorp Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket UE 170, PPL/702, Omohundro/1–2 (July 2005). The Company, however, agreed to include variable costs of new generation facilities in the TAM if it was able to recover fixed costs associated with those facilities on an expeditious basis. *Id.*

TAM. Including Chehalis decreased PacifiCorp's NPC by approximately $_______ without a corresponding increase in revenue requirement to reflect the fixed and O&M costs of the plant.

It would be contrary to balanced regulatory principles to accept the power cost advantages of the Chehalis plant in the TAM and deny the deferral of costs associated with that projection for future inclusion in rates. The Commission has noted the need to match revenues, expenses, and investments when making rates. *See Re Application of US West Communications, Inc. for an Increase in Revenues*, Dockets UT 125, UT 80, Order No. 00-191 at 13–14 (Apr. 14, 2000). ORS 757.259(2)(e) explicitly states that matching appropriately the costs borne by and the benefits received by customers is a basis for deferral. Deferring the fixed expenses will allow the Company to recover those costs if the Commission concludes that the plant is prudent.

The Company requests deferral of the Chehalis-related NPC decreases reflected in the 2009 TAM to allow the Company to recover those amounts in the event that the Commission disallows recovery of the Company's investment in the plant. Without such a mechanism, customers would have received the benefits of lower power costs resulting from the Chehalis plant, but would not have borne the costs of the plant. Such a result would be in violation of the Commission's policy on matching costs and benefits of resources. Deferring the NPC decreases caused by Chehalis will not unfairly prejudice customers—it would simply remove the inequity that would result if customers benefited from the plant without bearing any of its costs.

C. Proposed Accounting.

PacifiCorp proposes to account for the deferred fixed and the deferred variable expenses beginning on January 1, 2009 by recording the deferrals in Account 182

(Regulatory Assets). In accordance with ORS 757.259(3) and Order No. 08-263, PacifiCorp proposes to accrue interest on the unamortized balance in the account at the Company's authorized rate of return most recently approved by the Commission.

D. Estimate of Amounts.

PacifiCorp estimates that approximately $ _________ will be deferred on an Oregon allocated basis as fixed expenses of the Chehalis plant in 2009. PacifiCorp estimates that approximately $________ will be deferred on an Oregon allocated basis as the impact on NPC of the Chehalis plant in 2009. Attachment A to this Application shows the calculation of the estimated costs.

E. Notice.

A copy of the Notice of Application and a list of persons served with the Notice are attached to this Application as Attachment B.

IV. CONCLUSION

PacifiCorp respectfully requests that the Commission authorize the Company to defer the costs described in this Application in accordance with ORS 757.259.

DATED: July 25, 2008.

MCDOWELL & RACKNER PC

____
Katherine A. McDowell

Attorneys for PacifiCorp

Case UE-199
Exhibit PPL/302
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Andrea L. Kelly

DRAFT APPLICATION FOR DEFERRED ACCOUNTING FOR LAKE SIDE

July 2008

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM _____

In the Matter of the Application of PACIFICORP, dba PACIFIC POWER for a Deferred Accounting Order for Costs Associated with the Lake Side Generating Plant.	**APPLICATION FOR DEFERRED ACCOUNTING**

I. INTRODUCTION

Under ORS 757.259 and OAR 860-027-0300, PacifiCorp (the "Company") hereby requests that the Public Utility Commission of Oregon ("Commission") issue an order authorizing the Company to defer costs associated with the 545 megawatt Lake Side natural gas fired combined cycle generating plant in Vineyard, Utah. PacifiCorp requests deferral beginning on January 1, 2009 of the revenue requirement associated with the Lake Side plant not included in PacifiCorp's net power costs ("NPC") in the UE 199 Transition Adjustment Mechanism ("TAM"). PacifiCorp seeks this deferral to accurately track and preserve costs associated with Lake Side for later inclusion in rates.

II. NOTICE

Communications regarding this application should be addressed to:

Oregon Dockets	Katherine McDowell
PacifiCorp	McDowell & Rackner PC
825 NE Multnomah, Suite 2000	520 SW 6th, Suite 830
Portland, OR 97232	Portland, OR 97204
Telephone: (503) 813-5542	Telephone: (503) 595-3924
Email: oregondockets@pacificorp.com	Email: katherine@mcd-law.com

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

By email (preferred)	datarequest@pacificorp.com
By regular mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232
By facsimile	(503) 813-6060

III. DEFERRAL OF COSTS

The following information is provided pursuant to the requirements set forth in OAR 860-027-0300(3).

A. Description of Utility Expense.

PacifiCorp respectfully requests deferral of fixed and operations and maintenance ("O&M") costs associated with the Lake Side plant. These costs are not currently included in rates. In the Commission's order on PacifiCorp's 2009 TAM, the Commission included reductions in NPC caused by the Lake Side plant. Lake Side's impact on the system revenue requirement was not included in the 2008 or 2009 TAM because of the limited scope of the mechanism. As a result, customers are receiving the benefit of the Lake Side plant, in the form of a reduction to the Company's NPC, but have not been bearing the cost of the plant.

B. Reasons for Deferral.

This request seeks to match the costs associated with the investment in the Lake Side plant with the benefits of the plant received by Oregon customers. ORS 757.259(2)(e) allows the deferral of utility expenses or revenues where necessary to match appropriately the costs borne by and benefits received by customers.

The Lake Side plant went into service in September of 2007. The power cost benefits were included in Oregon NPC for 2008 and 2009 through the TAM. Including

Lake Side in the TAM in each of these years decreased NPC, causing customer rates to be lower than they would have been if Lake Side were not included in the TAM. Including Lake Side in the 2009 TAM decreased PacifiCorp's system NPC by approximately $110 million based upon the July update.

In its general rate case Docket UE 170, PacifiCorp originally objected to including variable costs of new generation facilities in the TAM.[1] The Company ultimately agreed to include variable costs of new generation facilities in the TAM if it was able to recover fixed costs associated with those facilities on an expeditious basis.[2]

In the Stipulation resolving the Company's last general rate case, Docket UE 179, the Company agreed not to file a general rate case prior to September 1, 2007.[3] The Stipulation also precluded PacifiCorp from seeking recovery of capital costs, including deferred recovery of any new generating resources in Oregon, before September 1, 2007.[4] As a result, the Company did not file for deferral or recovery of the Lake Side fixed costs prior to this Application.

This request seeks to align the costs of PacifiCorp's facilities with the benefits customers receive from such facilities. In the 2008 and 2009 TAM proceedings, parties had the opportunity to conduct discovery to address the prudence of the Lake Side project. No party objected to including Lake Side in the calculation of NPC in the TAM proceeding. It would be contrary to balanced regulatory principles to accept the power cost advantages of the Lake Side project in the TAM and deny the deferral of costs associated

[1] *Re PacifiCorp Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket UE 170, PPL/702, Omohundro/1–2 (July 2005).

[2] *Id.*

[3] *Re PacifiCorp Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket UE 179, Order No. 06-564, Appendix A at 6–7 (Oct. 2, 2006).

[4] *Id.*

with that project for future inclusion in rates. The Commission has noted the need to match revenues, expenses, and investments when making rates. *See Re Application of US West Communications, Inc. for an Increase in Revenues*, Dockets UT 125, UT 80, Order No. 00-191 at 13–14 (Apr. 14, 2000). ORS 757.259(2) (e) explicitly states that matching appropriately the costs borne by and the benefits received by customers is a basis for deferral.

C. Proposed Accounting.

PacifiCorp proposes to account for the deferred fixed expenses beginning on January 1, 2009 by recording the deferral in Account 182 (Regulatory Assets). In accordance with ORS 757.259(3) and Order No. 08-263, PacifiCorp proposes to accrue interest on the unamortized balance in the account at the Company's authorized rate of return most recently approved by the Commission.

D. Estimate of Amounts.

PacifiCorp estimates that approximately $14.6 million will be deferred on an Oregon allocated basis as fixed expenses of the Lake Side plant in 2009. Attachment A to this Application shows the calculation of the estimated costs.

E. Notice.

A copy of the Notice of Application and a list of persons served with the Notice are attached to this Application as Attachment B.

IV. CONCLUSION

PacifiCorp respectfully requests that the Commission authorize the Company to defer the costs described in this Application in accordance with ORS 757.259.

DATED: July 25, 2008

MCDOWELL & RACKNER PC

____
Katherine A. McDowell

Attorneys for PacifiCorp

Case UE-199
Exhibit PPL/303
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Andrea L. Kelly

OPUC RESPONSE TO DATA REQUEST 1.3

July 2008

PacifiCorp Data Request 1.3

Please provide support from the record in the proceedings establishing the TAM, that the TAM is limited to per kilowatt-hour changes in NVPC, similar to PGE and Idaho Power. (See page 3, line 8-9)

Response to PacifiCorp Data Request 1.3

Staff does not make the assertion on page 3, lines 8-9 that the proceedings establishing the TAM limited PacifiCorp to per kilowatt-hour changes in NVPC, similar to PGE and Idaho Power. Staff states that the proposed adjustment is consistent with PGE and Idaho Power's methodology within their mechanisms, which only allows per kilowatt-hour changes in NVPC.

Case UE-199
Exhibit PPL/400
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark R. Tallman

July 2008

Q. Please state your name, business address and present position with 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.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 23 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the testimony of Commission Staff ("Staff") witness Ms. Lisa Schwartz with respect to the proposed adjustment to the Rolling Hills capacity factor, the testimony of Staff witness Ms. Kelcey Brown and Industrial Customers of Northwest Utilities ("ICNU") witness Mr. Randall J. Falkenberg with respect to wind integration charges, and the testimony of Staff witness Ms. Brown on wind storage charges related to certain wind integration, storage, and return agreements. Specifically, my testimony demonstrates that:

- The Commission should reject Staff's Rolling Hills adjustment because it is based on flawed assumptions, is not supported by any facts in the record, and is contradicted by professionally performed studies,
- The Commission should reject Staff's and ICNU's wind integration adjustments because each adjustment arbitrarily reduces the comparatively low integration costs proposed in this case and misinterprets the Integrated Resource Plan ("IRP") Appendix J to estimate wind integration costs for various resource portfolio sizes, and
- The Commission should reject Staff's adjustment related to certain wind integration, storage, and return agreements because customers receive revenues under these contracts and should, therefore, be responsible for the costs the Company incurs to fulfill its obligations under the contracts.

Rolling Hills Capacity Factor

Q. Please briefly describe Staff's proposed adjustment to the Rolling Hills wind facility's capacity factor.

A. Based on Staff's testimony, Staff recommends that the Commission deem the capacity factor for the Rolling Hills wind project be set to 38 percent instead of the approximate 31 percent capacity factor expected by the Company based on site-specific studies (see Staff/200, Schwartz/3). The result of this adjustment on a net power cost basis is a reduction in the Company's test period revenues of $789,034 (see Staff/200, Brown/14) on an Oregon allocated basis. This is equivalent to a total system net power cost reduction for 2009 of approximately $3.0 million ($2,987,634 based on the System Generation (SG) factor of 26.41 percent).

Q. Does the $3.0 million system net power cost reduction represent the extent of Staff's proposed disallowance?

A. At this point, the Company can't tell. This type of adjustment is unprecedented and raises serious policy questions, some of which Staff will presumably address in the Renewable Adjustment Clause ("RAC") proceeding, Docket UE 200. Staff and intervenor testimony in the RAC is due on July 23, 2008; with confidential versions arriving on July 24, 2008, after my testimony was finalized for filing. Since the Company does not have Staff's RAC testimony, the Company reserves the right to respond to the broader set of issues implicated by this adjustment in its RAC rebuttal testimony or in its live sursurrebuttal in this proceeding.

Q. Please describe some of the most problematic issues implicated by Staff's proposed adjustment.

A. As I discuss later in my testimony, if a Commission-approved request for proposals ("RFP") requirement had existed for acquisition of the resource, the Company would have lost the opportunity to add the Rolling Hills project to its portfolio and take advantage of the federal production tax credit ("PTC"). The Company's experience demonstrates that any other wind alternative in PacifiCorp's service territory that could have been added after completion of such an RFP would have likely had higher capital and operating costs when completed, even if it was expected to operate at a higher capacity factor. Thus, if Staff's capacity factor adjustment were to be accepted by the Commission in this docket, there would need to be a corresponding upward adjustment to investment and operating expense in the RAC proceeding to preserve regulatory symmetry.

Additionally, Staff's proposal to artificially increase the capacity factor for the Rolling Hills wind project raises difficult issues regarding the existence of, and regulatory treatment for, the associated "phantom" renewable energy credits ("RECs") and "phantom" federal production tax credits.

Q. Has Staff conducted any studies related to the expected capacity factor from the Rolling Hills wind project?

A. No such study was presented by Staff.

Q. **Has the Company conducted any studies related to the expected capacity factor from the Rolling Hills wind project?**

A. Yes. Attached as Exhibit PPL/401 is the confidential report prepared by PacifiCorp's consultant that supports a projected capacity factor of approximately 31 percent (see page 1 "Summary of Findings"). This report was provided in response to ICNU Data Request 10.1 in UE 200.

Q. Since Staff does not have an independent study, what is the basis for Staff imputing a higher capacity factor for the project?

A. Staff's adjustment is based upon an elaborate series of speculative assumptions set in a hypothetical regulatory environment.

Q. Please explain.

A. Staff postulates that:

- **If** the Rolling Hills project is within five miles of any other Company wind project (in this case, the Glenrock wind project), **then** a distance-based project separation criteria established via a partial stipulation settlement agreement to the UM 1129 Public Utility Regulatory Policies Act ("PURPA") qualifying facility ("QF") docket applies, and

- **Therefore,** the Company is deemed by Staff to be constructing a single wind project that exceeds 100 MW in size, and
- **Therefore**, Staff declares that the Company is building a Major Resource under UM 1180 (the Commission's competitive bid guidelines), and
- **Therefore,** Staff interprets UM 1180 as requiring the Company to issue a RFP, and
- **If** the Company had issued a Commission-approved RFP, **then** the winning RFP bid would have been a wind resource with a 38 percent capacity factor or better, and
- **Theoretically**, the RFP process could have been completed, contracts negotiated, and the theoretical wind project permitted, constructed and interconnected to begin providing zero cost energy to Oregon customers at exactly the same time as the Rolling Hills project; and
- **Therefore**, the capacity factor of the Rolling Hills project should be artificially deemed to be equal to 38 percent instead of 31 percent, and
- **Therefore**, the Company should incur a test year disallowance equal to approximately $3.0 million on a system basis; regardless of overall project economics or long-term value to customers.

Q. Let's take each of these items in turn. Is it appropriate for Staff to apply the UM 1129 PURPA QF distance-based criteria to the Rolling Hills project?

A. No. It is entirely inappropriate for Staff to apply the distance-based criteria from the partial stipulation resulting from UM 1129.

Q. Why is it inappropriate?

A. The partial stipulation from UM 1129 is associated with PURPA QF resources. The Rolling Hills project is clearly not a PURPA QF resource. In addition, the partial stipulation is expressly for the purpose of determining PURPA QF eligibility for standard avoided cost rates and a standard form of contract and not for any other purpose.

Q. What other intent is reflected in the UM 1129 partial stipulation?

A. The partial stipulation expressly sets forth that no party shall be deemed to have approved, admitted or consented to the facts, principles, methods, or theories employed by any other party in arriving at the terms of the partial stipulation. Finally, the partial stipulation expressly sets forth that no party shall be deemed to have agreed that any provision of the partial stipulation is appropriate for resolving issues in any other proceeding.

Q. Who were the parties to the UM 1129 partial stipulation?

A. There were several parties to the partial stipulation including; three utilities, an Oregon County, and two state agencies (Staff and the Oregon Department of Energy ("ODOE")).

Q. Is Staff's application of a unilaterally determined, distance-based criteria consistent with the criteria utilized by the ODOE?

A. No. Staff's application of distance-based criteria for non-QF projects is inconsistent with the criteria applicable to ODOE in the Oregon Administrative Rules that apply with respect to the Oregon Business Energy Tax Credit ("BETC"). ODOE does not establish distance-based criteria in determining BETC applicability. Instead, the applicable rules establish a series of criteria to be considered in determining essential characteristics of a renewable energy resource facility. Indeed, ODOE explicitly recognizes that PURPA QFs have different criteria and directly references UM 1129 to set forth separate criteria applicable only to PURPA QFs.

Q. Does the Energy Facility Siting Council ("EFSC") in Oregon have distance-based criteria for wind projects?

A. No. EFSC does not have distance-based criteria for wind projects. This is for good reason as wind projects are unique as compared to other forms of generation.

Q. Do the Rolling Hills and Glenrock wind projects constitute Major Resources pursuant to UM 1180?

A. No. The Rolling Hills and Glenrock wind projects do not constitute Major Resources under UM 1180 because UM 1180 does not set forth distance-based criteria to determine if multiple projects constitute a deemed single project. UM 1180 sets forth that the only criteria is size (>100 MW) and duration (>5 years).

Q. Are the Rolling Hills and Glenrock wind projects separate and distinct resources?

A. Yes. The Company made the decision to advance the Rolling Hills project on

December 20, 2007, nearly 7 months after the decision to advance the Glenrock project was made. Each project was analyzed and approved as a separate and distinct undertaking.

Q. Was the decision to advance the Rolling Hills wind project undertaken to take advantage of unique circumstances that existed at the time?

A. Yes. The wind turbines being installed at the Rolling Hills project were procured for another project located in another state. When the Company decided not to pursue the other project, it determined that the Rolling Hills project was the best project to pursue to ensure that a project could be completed in time to take advantage of the federal production tax credit before it is set to expire on December 31, 2008. In addition, the Company expects to take advantage of bonus depreciation, which also expires at that time. I discuss the value of these factors later in my testimony.

Q. Does Staff offer any evidence to demonstrate that procuring resources via an RFP would result in a more cost-effective resource portfolio?

A. No. Staff offers no such testimony or evidence.

Q. Is there any basis for the Commission to conclude that RFPs are the only prudent or effective way to procure resources?

A. No. There is no basis to conclude that RFPs always result in a more desirable resource portfolio. In fact, in early 2007, the Oregon Commission made a contrary observation, noting that it expected "the company to fully explore * * * renewable resources * * * at levels incremental to the amounts in the acknowledged 2004 IRP Action Plan," and "that competitive bidding may not be the appropriate mechanism to acquire all resources that may be part of the best cost/risk portfolio." *In re*

PacifiCorp, Order No. 07-018, UM 1208 at 6 (January 16, 2007).

As a practical matter, if the Company had been required to conduct an RFP for every new renewable resource, the Company could not have met its transaction commitment to have 400 MW of new renewable resources in its portfolio by December 31, 2007. And, neither the Company nor Oregon would be in a position to proudly note that we expect to reach more than 1,100 MW of wind capability in the Company's portfolio by the end of 2008 from a balance of owned and contracted resources.

Q. Did the Company follow the Commission's direction in Order No. 07-018?

A. Yes. The Company followed the Commission's direction in working to meet its renewable resource targets, using both the competitive bidding processes and other acquisition processes as appropriate for the resources in the TAM and RAC dockets. The Company considered factors such as market changes, the continuing rise in major equipment and construction costs, and the reasonable expectation that a resource could be placed in-service before the then-current expiration of the federal production tax credit. In each case, whether or not the competitive bidding process established in UM 1180 was applicable, the Company employed prudent analytical tools to determine the cost-effectiveness of the resource.

Q. Does Staff offer any evidence to support its conclusion that the Company would have obtained the "assumed" 38 percent capacity factor if it had issued a RFP?

A. No. Staff only offers general references to the assumptions made in the 2007 IRP and to other projects that the Company is developing in Wyoming.

In determining which renewable projects to pursue, the Company is guided by whether a project is cost effective. Capacity factor is just one element of determining the cost-effectiveness of a project. Moreover, the 38 percent capacity factor in the IRP represents a target for the Company's total renewable portfolio. By definition, some projects will have higher capacity factors than 38 percent and some lower. Again, the critical determination is cost effectiveness, not merely capacity factor.

Q. Does Staff's set of assumptions and conclusions fail the sensibility test?

A. Yes, for all of the reasons demonstrated above. In addition, Staff's back-door prudence disallowance fails to examine any factor other than capacity factor.

Q. What economical aspects does Staff fail to examine with respect to the Rolling Hills project?

A. Staff fails to account for the fact that since the Company owns the land, third party leasing costs will be avoided and a savings of approximately $128 million over the 25-year life of the project can reasonably be expected. Indeed, this cost avoidance is in perpetuity, which means the Company will successfully avoid four times this amount over the next 100-years (approximately $551 million or more) and this 100-year value would have the effect of equaling a like project with over a 45 percent capacity factor located on leased land.

Q. What other economic factors did Staff fail to consider?

A. Staff fails to account for the fact that the Company is advancing the Rolling Hills wind project for the express purpose of adding a renewable resource to the portfolio that can take advantage of the federal production tax credit and hedge against construction and equipment costs that are rising at multiples of inflation. Indeed, the value of the federal production tax credit to customers is approximately $98 million.

Staff's interpretive conclusion using arbitrary and un-established distance-based criteria would have resulted in the Rolling Hills project being deferred until a formal Commission-approved RFP process could be completed. Therefore, the wind turbines made available to the Company would be foregone and there would be no practical ability for the project to meet the current tax credit window. In addition to potentially lost tax credit value, Staff's interpretation would have subjected customers to higher equipment and construction costs. A reasonable estimate of how quickly wind project costs are rising is approximately 10 percent or more per year. This is equivalent to approximately $20 million for the Rolling Hills project.

Q. If Staff's hypothetical 38 percent capacity factor was applied for each year of the life of the Rolling Hills project, what is the true magnitude of Staff's proposed disallowance?

A. Staff's proposed disallowance results in approximately a staggering $115 million net power cost disallowance to the Company when taken on a Company-wide basis over the expected life of the project. This represents approximately 56 percent of the entire expected project cost and is punitive and unreasonable. The $115 million disallowance amount does not even account for further disallowances associated with the potentially "phantom" RECs and federal production tax credits. For example, the implied disallowance associated with the tax credits is more than $22 million.

Q. Is Staff's proposal consistent with Oregon State energy policy?

A. No. As described above, Staff's proposal is in conflict with ODOE criteria. More troubling, however, is that Staff's proposal appears to be in direct conflict with Oregon's renewable portfolio standard legislation which both requires the Company to meet a significant portion of its energy needs with renewable resources and provides for cost recovery of the Company's associated investment.

If adopted, Staff's proposal will significantly impede the Company's ability to acquire cost-effective renewable resources and build the type of generation portfolio contemplated by the IRP that balances cost and risk. If the Company is forced to adhere to a newly established criteria where all renewable energy resources must be acquired via a RFP process, then it could delay acquisitions by years and cause the Company to lose access to the best sites and the ability to procure turbines and construction services in a market that continues to have escalating costs. This would make compliance with the Oregon renewable portfolio standard more costly and less cost effective, which is neither rational, consistent with the intent of the legislation nor in the interests of customers.

If Oregon wants the Company to actively pursue cost-effective renewable resources, then the Commission should construe its resource acquisition policies flexibly with this goal in mind. Because Staff's proposed adjustment is antithetical to such an approach and because UM 1180 does not contain a distance-based criteria, the Commission should reject it.

Wind Integration

Q. Please summarize your wind integration testimony.

A. My wind integration testimony rebuts the testimony of Staff (see Staff/100, Brown/7), in which Staff incorrectly concludes $0.11/MWh is the correct rate for calculating wind integration costs in this proceeding. In addition, my testimony rebuts the testimony of ICNU (see ICNU/100 Falkenberg/71-73), in which Mr. Falkenberg asserts that the Company need not carry reserves associated with wind resources and that a more reasonable wind integration rate is $0.58/MWh. My testimony also explains that the Company is including applicable Bonneville Power Administration (BPA) wind integration tariff charges in the TAM update.

Q. How large is Staff's proposed adjustment based on the $0.11/MWh rate?

A. $800,605 (see Staff/100, Brown/7, line 23) for the test period or $3,031,446 on a total system basis using a System Generation allocation factor of 26.41 percent.

Q. Why is Staff's proposed rate of $0.11/MWh incorrect?

A. Staff manually determined $0.11/MWh by interpreting graphs printed in Appendix J to PacifiCorp's acknowledged 2007 IRP in Docket LC 42 (see Staff/100, Brown/7, line 20). In making this determination, Staff incorrectly utilized Figure J.4 in Appendix J of the IRP.

Q. Why was it incorrect to utilize Figure J.4?

A. Staff was attempting to ascertain the integration cost on a $/MWh basis for a wind portfolio of 701 MW. Figure J.4 is a graph that only applies to a wind portfolio of 2,000 MW.

Q. What is the Company's filed integration cost in this docket?

A. The Company's filed integration cost is $1.14/MWh and is based on the 2007 IRP.

Q. Using the methodology in the IRP, what is the integration cost for a 700 MW wind portfolio?

A. Approximately $1.21/MWh. The Company provided this information to Staff in response to data request OPUC 59 (attached as Exhibit PPL/402) and responded to Staff's follow-up questions with respect to OPUC 59 on July 2, 2008.

Q. Staff is focused on a wind portfolio of 701 MW. Will the Company have more than 701 MW of wind resources on its system during the test period?

A. Yes. Inclusive of the wind resources in this case, the Company will have more than 1,500 MW of wind resources on its system during the test period. This amount includes Company owned wind resources, third party owned resources for which the Company buys the output under contract, third party owned resources that the Company integrates, stores, and returns under contract, and third party owned resources not applicable to a Company integration tariff. Excluding the resources covered by the BPA wind integration tariff, the Company will be integrating approximately 1,320 MW of wind resources.

Q. How does Staff's proposed $0.11/MWh translate into the amount of dispatchable resource set aside to provide integration services?

A. Referring to Exhibit PPL/402 (response to data request OPUC 59), it can be seen that the amount of dispatchable resource estimated for a 700 MW wind portfolio is 17 MW and, as mentioned above, the associated integration cost is $1.21/MWh. The Company estimates that a proposed integration cost of $0.11/MWh translates into about 2 MW of dispatchable resource for providing this service.

Q. Is it reasonable to expect that a portfolio of wind resources of 701 MW or more will be subject to variations that exceed 2 MW?

A. Yes. A wind project portfolio of that size is capable of variations much larger than 2 MW.

Q. ICNU witness Mr. Falkenberg asserts that he sees no basis for including wind integration costs of $1.1/MWh and 5 percent reserves modeled in GRID. Is Mr. Falkenberg correct?

A. No. Mr. Falkenberg has misinterpreted Appendix J of the IRP, has incorrectly referenced the 5 percent reserve requirement modeled in GRID and has failed to correctly reference the Company's filed $1.14/MWh wind integration cost relative to what is modeled in GRID.

Q. Please explain.

A. Appendix J to the IRP is intended to analyze wind integration costs that are above and beyond the reserve requirements the Company is obligated to carry. The Company is currently obligated via the Northwest Power Pool ("NWPP") to carry 5 percent reserves associated with wind resources. This reserve obligation is modeled in GRID. Appendix J to the IRP studies wind integration costs above and beyond the NWPP requirement.

Q. Mr. Falkenberg concludes that the Company will have approximately 1,200 MW of wind capacity installed during the test year and that the correct level of incremental reserve requirement is 10 MW. Has Mr. Falkenberg made the same mistake as Staff in interpreting Figure J.4 of Appendix J to the IRP?

A. Yes. Mr. Falkenberg has made the exact same mistake as Staff and, as a result, Mr. Falkenberg's claim that an integration cost much lower than the Company's filed rate of $1.14/MWh is flawed. As the response to data request OPUC 59 demonstrates, the Company's proposed rate of $1.14/MWh is reasonable for wind portfolios that range in size from 700 MW to 2,000 MW.

Q. Mr. Falkenberg claims that the Company has failed to provide any reasonable analysis of wind integration costs. Do you agree with this?

A. No. Appendix J to the IRP provides a perfectly reasonable proxy for wind integration costs and, when compared to the BPA tariff for wind integration costs, results in projected costs that some may consider too low.

Q. For comparison purposes, what is the BPA integration tariff on a $/MWh basis?

A. As the parties to this case are aware, BPA has recently added a wind integration tariff of $0.68 per kilowatt month for interconnected wind projects. This represents approximately $2.82/MWh for a wind plant with a capacity factor of 33 percent. This rate is more than double the Company's filed rate of $1.14/MWh.

Q. Has the Company updated its TAM filing to include the BPA wind integration tariff for Leaning Juniper and Goodnoe Hills?

A. Yes. For these projects, the Company has replaced its filed $1.14/MWh wind integration cost with the higher tariff rate charged by BPA. Mr. Falkenberg's testimony supports this update. See ICNU/100 Falkenberg/73.

Q. Is it reasonable and appropriate for the Company to include in this docket a 5 percent reserve requirement in GRID for wind resources and an integration cost pursuant to IRP Appendix J of $1.14/MWh?

A. Yes. The 5 percent reserve requirement should be included due to the Company's participation in the NWPP and the response to data request OPUC 59 demonstrates that a $1.14/MWh integration cost is reasonable.

Wind Integration, Storage, and Return Contract Adjustment

Q. Please explain Staff's other wind integration adjustment.

A. Staff proposes an adjustment of $189,093 (see Staff/100, Brown/8, line 4) for the test period, or approximately $715,990 on a system basis, based on Staff's incorrect perception that the Company is double recovering integration costs associated with wind storage contracts.

Q. What are the integration, storage, and return contracts that Staff references in its proposed adjustment?

A. Foote Creek I, II, III, IV, and Seattle City Light ("SCL") State Line.

Q. Why does Staff believe that double recovery may be occurring?

A. Staff incorrectly asserts that cost recovery for providing wind integration services has been included in these contracts since their inception.

Q. Please explain why Staff's assertion is incorrect.

A. The contracts set forth what the Company charges its counterparty and, as such, establish the revenues the Company receives. All of this revenue is then credited to customers via the rate making process. In response to data request OPUC 20 (attached as Exhibit PPL/403), the Company explained that the revenues from these contracts are recorded in Other Electric Revenue (Account 456).

Q. With respect to wind integration, what charges are the Company seeking to recover in this docket associated with the integration, storage, and return contracts identified by Staff?

A. The Company is seeking to only recover its costs to provide the integration services. As mentioned already, customers receive the revenue benefit of these contracts via

Account 456. The Company is merely seeking to recover the cost side of the equation.

Q. Is the Company double recovering the cost of integration if an integration charge associated with the integration, storage, and return contracts identified by Staff is included in GRID?

A. No.

Q. What does the Company recommend with respect to the wind integration adjustment proposed by Staff?

A. The Commission should reject Staff's proposed wind integration, storage, and return contract adjustment of $189,093 (Oregon allocated) on the basis that Staff incorrectly concludes that the Company is double recovering its costs. Alternatively, if Staff's wind integration, storage, and return adjustment were to be accepted by the Commission in this docket, the revenue being credited to Account 456 would need to be removed to preserve regulatory symmetry.

Q. Does this complete your testimony?

A. Yes.

Case UE-199
CONFIDENTIAL
Exhibit PPL/401
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL

Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

CONSULTANT REPORT ON ROLLING HILLS

July 2008

THIS EXHIBIT IS CONFIDENTIAL AND WILL BE PROVIDED UNDER THE TERMS OF THE PROTECTIVE ORDER IN THIS CASE

Exhibit PPL/402
Tallman Exhibit

Case UE-199
Exhibit PPL/402
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

OPUC DATA REQUEST 59

July 2008

OPUC Data Request 59

Using your findings in Appendix J of the 2007 IRP please provide the incremental reserve requirement for 701 MW, and the corresponding cost of those incremental reserves. Please discuss why PacifiCorp believes that the $1.14/MWh integration charge, which is associated with incremental reserves of 43 MW, is appropriate for the 701 MW wind portfolio currently included in the 2009 test year.

Response to OPUC Data Request 59

The $1.14/MWh integration charge is an average charge calculated to cover the first 2,000 MW of wind added to the system. The wind integration analysis was not intended to justify a different value for each increment of wind resource that is added to the system.

As a result of this request, the Company performed the requested calculation as well as each of the other annual increments consistent with the IRP. The results are provided in Attachment OPUC 59. For 700 MW, the resulting price was $1.21/MWh. This value is higher than most of the other values because the first 700 MW has a lower capacity factor than much of the later wind additions.

Please refer to Company's response to OPUC Data Request 18 for the data needed for these calculations.

Cost of Load Following Reserves with Wind Penentration

	700 MW	1000 MW	1100 MW	1400 MW	1600 MW	1700 MW	2000 MW
17	$1.21	$0.82	$0.74	$0.57	$0.49	$0.46	$0.40
22	$1.61	$1.08	$0.99	$0.76	$0.65	$0.62	$0.53
23	$1.69	$1.14	$1.04	$0.79	$0.68	$0.65	$0.55
29	$2.19	$1.47	$1.34	$1.03	$0.88	$0.83	$0.71
36	$2.77	$1.86	$1.70	$1.30	$1.12	$1.06	$0.90
41	$3.20	$2.15	$1.96	$1.50	$1.29	$1.22	$1.04
43	$3.37	$2.27	$2.07	$1.58	$1.36	$1.29	$1.10
55	$4.42	$2.97	$2.71	$2.07	$1.79	$1.69	$1.44
80	$6.68	$4.49	$4.09	$3.13	$2.70	$2.55	$2.18

700 MW = 2007885 MWh
1000 MW = 2987716 MWh
1100 MW = 3282569 MWh
1400 MW = 4279148 MWh
1600 MW = 4978874 MWh
1700 MW = 5274728 MWh
2000 MW = 6178129 MWh

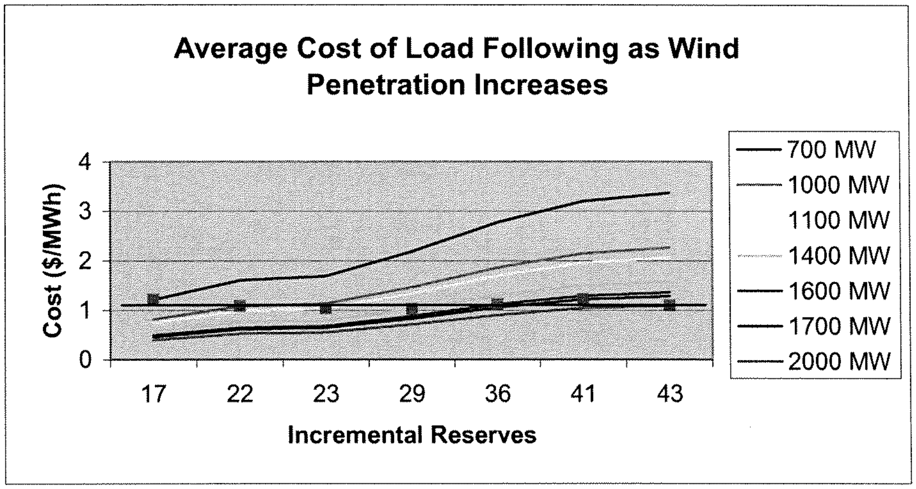


Exhibit PPL/403
Tallman Exhibit

Case UE-199
Exhibit PPL/403
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

OPUC DATA REQUEST 20

July 2008

OPUC Data Request 20

With respect to the agreements that PacifiCorp has with the owners of these wind facilities, currently included in the NPC report rows 672-676, please (a) provide the revenue associated with agreements and (b) indicate where the revenue is accounted for in the company's filing in this case. If not included in this filing, (c) where is this revenue accounted for in the company's rates and (d) how much is included? In addition, please provide the (e) total revenue and MWh for each of these agreements received in 2007, (f) forecasted to receive for 2008, and forecasted to receive for 2009. Please provide all information with an Excel document electronically.

Response to OPUC Data Request 20

To the extent this request seeks revenues for these facilities, PacifiCorp objects to this request as irrelevant because revenues associated with these agreements are not included in the TAM, which is limited to an annual update of PacifiCorp's NVPC. This revenue is recorded in Other Electric Revenue (Account 456). In Order No. 07-446 (UE 191), the Commission found that the Camas contract adjustment, which also related to revenues included in Other Electric Revenue in UE 179, was outside the scope of the TAM proceeding.

Without waiving this objection, the Company provides the following response.

a. Please refer to Attachment OPUC 20a.

b. This revenue is not part of the Transition Adjustment Mechanism filing.

c. FERC 456, Other Revenue

d. Please refer to Attachment OPUC 20d for the amounts included in the Company's last general rate case filing, UE 179. UE 179 concluded with a Stipulation that identified only high-level adjustments to arrive at a revenue requirement. For these reasons, Pacific Power is not able to quantify the specific level of specific revenues for these wind facilities included in rates from UE 179.

e. Please refer to Attachment OPUC 20a.

f. Please refer to NPC report rows 672-676 for forecasted MWh. The forecast is the same for both years. The Company does not produce revenue forecasts.