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June 27, 2005

Via Electronic and US Mail

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

Re: In the Matter of PACIFIC POWER & LIGHT Request for a General Rate Increase in the Company's Oregon Annual Revenues
Docket No. UE 170

Dear Filing Center:

Enclosed please find the following items for filing in the above-referenced proceeding on behalf of the Industrial Customers of Northwest Utilities:

- One original and five (5) copies of the Surrebuttal Testimony of Randall Falkenberg, with Exhibits ICNU/112 and ICNU/113;

- One original and five (5) copies of the Surrebuttal Testimony of James Selecky; and

- One original and five (5) copies of the Surrebuttal Testimony of Kathryn Iverson.

Thank you for your assistance.

Sincerely,

/s/ Sheila R. Ho
Sheila R. Ho

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Surrebuttal Testimonies of Randall Falkenberg, James Selecky and Kathryn Iverson on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list by causing the same to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 27th day of June, 2005.

/s/ Sheila R. Ho
Sheila R. Ho

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

SURREBUTTAL TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

JUNE 27, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this case.

Q. WHAT IS THE PURPOSE OF THIS SURREBUTTAL TESTIMONY?

A. I will reply to the rebuttal testimony of PacifiCorp witnesses Omohundro, Taylor, Tallman, Widmer, and Wrigley. This testimony will address issues related to the jurisdictional allocation of Existing Qualifying Facility ("QF") Contracts, new resources, Resource Valuation Mechanism ("RVM") power cost issues, and the Georgia-Pacific ("G-P") Camas contract.

<u>Existing QF Contracts</u>

Q. WERE YOU INVOLVED IN THE MSP PROCESS AND UM 1050?

A. Yes. I was the Industrial Customers of Northwest Utilities' ("ICNU") witness in UM 1050, and I have participated in many Multi-State Process ("MSP") meetings and workshops over the past three years. I am continuing to participate in the MSP meetings regarding load growth, the Hybrid proposal, and the implementation of the Revised Protocol.

Q. HAVE YOU REVIEWED THE TESTIMONY OF PACIFICORP WITNESS TAYLOR CONCERNING THE ALLOCATION OF EXISTING QF CONTRACTS?

A. Yes. Mr. Taylor does not agree that the Desert Power, Kennecott, Tesoro, and US Magnesium contracts qualify as Existing QF Contracts in the Commission-approved Revised Protocol. Mr. Taylor's arguments ignore the most important language actually contained in the document.

Q. MR. TAYLOR RELIES ON THE LANGUAGE IN SECTION II OF THE REVISED PROTOCOL ("PROPOSED EFFECTIVE DATE") TO RATIONALIZE

THAT THE FOUR CONTRACTS WERE NEW RATHER THAN EXISTING CONTRACTS. PLEASE COMMENT.

A. Mr. Taylor views June 1, 2004, as the "effective date" of the Revised Protocol based on the language of Section II. However, "effective date" is not a defined term in the Revised Protocol. Thus, one must try to interpret its meaning based on the intentions of the parties.

Q. DOES ANYTHING IN SECTION II ADDRESS QF CONTRACTS?

A. No. The language in Section II does not indicate that the *proposed* effective date has any relationship to the designation of Existing QF Contracts; it merely suggests that PacifiCorp will use the Revised Protocol in cases filed after June 1, 2004. Had the parties intended that Existing QF Contracts be defined as those that were executed before June 1, 2004, it would have been a very simple matter for the definition of Existing QF Contracts to have stated so. Instead, the definition of Existing QF Contracts provides as follows:

> **"Existing QF Contracts"** means Qualifying Facility Contracts entered into prior to the effective date of this Protocol, but not such contracts renewed or extended subsequent to the effective date of this Protocol.

Re PacifiCorp, OPUC Docket No. UM 1050, Order No. 05-021, Attachment A at 50 (Jan. 12, 2005). This clearly suggests that the parties did not intend for Existing QF Contracts to be defined as those that were entered into prior to June 1, 2004. This telling point belies all of Mr. Taylor's arguments.

It is also ironic that Mr. Taylor would rely upon the "Proposed Effective Date" language of Section II, while completely ignoring the far more significant language of Section XIII D (emphasis added):

> *The Protocol shall only be in effect for a State upon final ratification by its Commission.* Absent the final adoption of the Protocol, the Company will continue to bear the risk of inconsistent allocation methods among the States.

This language clearly indicates what common sense tells us: the Revised Protocol could only be in effect for a state *after* adoption by its Commission, not before. Certainly before final adoption, the document is also "absent the final adoption." Consequently, the Company bears the risk of inconsistent allocation methods prior to final adoption. As the four contracts in question were all entered into during the period before (or absent) final adoption of the Revised Protocol, they should be treated as Existing QF Contracts.

Q. DOES THE LANGUAGE IN SECTION XIII MAKE ANY SENSE UNDER MR. TAYLOR'S THEORY?

A. No. Under Mr. Taylor's novel theory there was no need for the language from Section XIII, quoted above, to have been included in the document. If June 1, 2004, was the effective date, why did the parties insist that the document say it would not be effective for a state until final adoption by its Commission? Why didn't they define the effective date as June 1, 2004?

Q. DOES SECTION II ACTUALLY STATE THAT JUNE 1, 2004, IS THE "EFFECTIVE DATE?"

A. No. It merely calls June 1, 2004, a "*proposed* effective date." If nothing else, this suggests that adoption of that date was not a requirement for ratification. Further, there was nothing in the Commission's Order in UM 1050 indicating that it had specifically approved of the "*proposed* effective date." Nor did the Commission indicate in the Order that it would supersede the language of Section XIII with the *proposed* effective date language of Section II. Since UM 1050 was not even submitted to the Commission for decision until long after June 1, 2004, it should be obvious that the June 1, 2004, "*proposed* effective date" was both meaningless and impossible by that time.

Q. MR. TAYLOR TESTIFIES ON PAGES 3-4 THAT IT WAS EXPECTED THAT FINAL RATIFICATION OF THE REVISED PROTOCOL WOULD OCCUR AFTER ITS EFFECTIVE DATE. PLEASE COMMENT.

A. This is nonsensical on its face. The document itself says it is not effective for a state until final ratification by its Commission. Mr. Taylor focuses on what he would like for the document to have said, rather than what it actually says.

Q. IN THE SAME PASSAGE, MR. TAYLOR INDICATES THE COMPANY REQUESTED A JUNE 1, 2004, EFFECTIVE DATE BECAUSE THE COMPANY WAS PLANNING ON FILING RATE CASES PRIOR TO APPROVAL OF THE REVISED PROTOCOL BY THE VARIOUS STATES AND WANTED TO USE THE REVISED PROTOCOL. PLEASE COMMENT.

A. His comments concerning the Company planning to use the methodology in rate cases it filed before the approval of the Revised Protocol may be true, but they also are irrelevant. There was nothing to stop PacifiCorp from filing rate cases in *any* state using *any* method it preferred before or after June 1, 2004.

Further, Mr. Taylor should recall that the document was being negotiated from March to May 2004. At that time, the procedural schedule in UM 1050 was fairly "tight," suggesting a decision might have been obtained much more quickly than ultimately occurred. During the discussions, the Company was very mindful of the fact that it planned to file an Oregon rate case in the near future. This was another time pressure that drove the process to some extent. At the time, there was a concerted effort to expedite the discussion process to come to a quicker resolution. Perhaps by expediting the process to obtain quick approval of the document, the Company lost sight of the implications of the language in Section XIII. In the end, it matters little, because the language of the document is what was agreed upon by parties in four states and approved by the Oregon Commission in January 2005.

Finally, it was impossible for all aspects of the Revised Protocol to be retroactively effective to June 1, 2004. For example, the Revised Protocol requires creation of a Standing Committee. That process has just now begun. It most certainly was not "effective" retroactive to June 1, 2004. Neither can the Company simply decide unilaterally that as of June 1, 2004, the Commission had adopted the Revised Protocol, making it effective for all QF contracts entered into after that date.

Q. HAS THE COMPANY ALREADY DECLINED TO MAKE THE REVISED PROTOCOL RETROACTIVELY EFFECTIVE IN OTHER STATES?

A. Yes. PacifiCorp filed a rate case in Washington in late 2003 under the Original Protocol method. In the course of the case it was revealed that the Company would have had a lower revenue requirement in Washington under the Revised Protocol than under the Original Protocol. However, in that case, the Company opposed ICNU's proposal to compute Washington revenue requirements using the Revised Protocol (with certain adjustments). In September 2004, a decision in Washington was rendered, based on a Stipulation that was premised upon the Original Protocol.

Q. DID THE PACIFICORP FILING IN THE UTAH CASE TREAT THE US MAGNESIUM CONTRACT IN THE MANNER PROPOSED IN OREGON BY MR. TAYLOR?

A. No. The US Magnesium contract was treated as an "*Existing QF Contract*" in the Company's original Utah filing. In Oregon, the Company filed a rate case a few months later, but considered the very same contract a "*New QF Contract*." While the Company subsequently renegotiated the contract and amended its filing in Utah, the contract included in the Oregon filing is, in fact, the original contract as filed in Utah. This is obvious because the renegotiated US Magnesium contract has no demand charges, while the original contract did. In both the Utah and Oregon rate case filings, the US

Magnesium contract modeled in the power cost studies contains the same demand charges ($326,750 per month) in the months that the two test years had in common (January to March 2006). The same is true of the February 2005 update. To my knowledge, this contract is still the basis for the Company's ECD calculations. PPL/403, Taylor/1.

Q. ARE THERE ANY OTHER REASONS THAT THIS ISSUE SHOULD BE OF CONCERN TO THE COMMISSION?

A. Yes. In my testimony in UM 1050, I pointed out that PacifiCorp had provided rate caps to guarantee that Utah revenue requirements under the Revised Protocol would not differ significantly from Utah's preferred rolled-in method. This raises a "red flag," because it implies that the Company would now have an incentive to "side" with Utah in any future disputes concerning the Revised Protocol. Because the Revised Protocol has already resulted in Utah revenue requirements exceeding the stipulated rate cap, it is unlikely that the Company would be able to recover the costs of these contracts in that state if they are treated as Existing QF Contracts. This means that the Company is not in a position to be "an honest broker" in situations of this nature. This is exactly the type of situation I warned of in my UM 1050 testimony. This clearly is not a case where the Commission can view the Company as an impartial arbiter between the States.

Q. MR. TAYLOR HIGHLIGHTS THE LANGUAGE OF THE VARIOUS QF CONTRACTS THAT DESIGNATES THEM AS "NEW CONTRACTS" UNDER THE TERMS AND CONDITIONS OF THE REVISED PROTOCOL. PLEASE COMMENT.

A. There are multiple flaws with this argument. *First*, Mr. Taylor assumes that the Oregon Commission is somehow bound by self-serving agreements made between PacifiCorp and QF developers in other states. *Second*, the Oregon Commission never had the opportunity to approve the contracts in question, as they were only submitted for approval to the Utah Commission. *Finally*, the fact that PacifiCorp felt it necessary to include such language in such contracts indicates that perhaps they themselves realized this was an issue that might be problematical for the Company. I fail to see how any of this provides a compelling reason for the Commission to adopt Mr. Taylor's position.

Q. ON PAGE 5, MR. TAYLOR TESTIFIES THAT IT WOULD BE UNREASONABLE FOR ANY STATE TO BE ABLE TO ALTER ITS ALLOCATION OF QF CONTRACTS BY THE TIMING OF ITS APPROVAL OF THE REVISED PROTOCOL. PLEASE COMMENT.

A. The language certainly does that for all states. However, the language in question gave Utah the incentive for an early approval of the Revised Protocol. Utah could have been able to reduce its potential impact from the allocation of Existing QF Contracts by approving the document sooner rather than later. Ultimately, Utah did not approve the Revised Protocol until December 2004, even though the stipulation in that state was signed in May 2004. Utah certainly had some opportunity to mitigate the impact of Existing QF Contracts. Because Utah was the state that precipitated the "break" in the prior jurisdictional allocation method, I believe other states waited until Utah approved the Revised Protocol. Certainly, there would have been no reason for other states to adopt the Revised Protocol if Utah had turned it down, with all of the protections of the stipulation in that state.

Q. ON PAGES 6-7, MR. TAYLOR SUGGESTS THAT THE OREGON PARTIES WHO SIGNED THE STIPULATION UNDERSTOOD THE IMPACT OF THE EXISTING VS. NEW QF ISSUE. PLEASE COMMENT.

A. Mr. Taylor references studies in which the Existing QF Contracts were modeled during the MSP process. Whatever the results of those studies, they have no bearing on the language of the document, which is controlling. Indeed, the Company has been clear that it was never willing to guarantee Oregon any of the "savings" projected in such studies related to the Hydro Endowment. It cannot now claim that these model runs are more significant than the Revised Protocol document itself. Ironically, the treatment of the US Magnesium contract in those studies did not prevent the Company from filing its Utah rate case with the contract modeled as an Existing Contract, as noted above.

Q. CAN THE OREGON COMMISSION ADOPT THE COMPANY'S PROPOSAL AND REMAIN FAITHFUL TO THE TERMS OF THE REVISED PROTOCOL?

A. No. If the Commission wishes to reclassify the four contracts as "New Contracts," it would be necessary for it to bring the matter before the Standing Committee. The other four states that approved the document would have a say in the matter. While Utah obviously might prefer PacifiCorp's interpretation, Wyoming and Idaho may not. Even if one believes there is some ambiguity in the meaning of the document, the Commission should follow the interpretation that makes the most sense. It could then take the matter before the Standing Committee and, if it wishes, propose an amendment to the document to allow PacifiCorp's interpretation to be implemented in the future. Because it appears this issue may not have any impact on Utah's rates for a number of years, going through the Standing Committee is a logical option.

Shortly, the Standing Committee will be considering issues such as structural protections for load growth and seasonal allocations. The definition of Existing QF Contracts is an issue that could be raised in the context of those discussions if the Commission so desires.

New Resources

Q. MR. TALLMAN TESTIFIES THAT WEST VALLEY COSTS HAVE BEEN REFLECTED IN RATES SINCE 2002 AND THAT GADSBY'S COSTS HAVE BEEN INCLUDED IN RATES SINCE 2003. IS THIS RELEVANT TO THE ISSUES OF PRUDENCE OR THE MARKET VALUE RULE?

A. No. These costs were included in rates as the result of stipulations in UE 134 and UE 147. As such, there is no precedent established by those cases. Further, as noted by Mr. Tallman, Commission Order No. 02-657 indicated that the Commission did not make a prudence finding regarding the West Valley lease in UI 196. Consequently, the prudence of West Valley has never been established because the Commission never decided the issue in UE 134 either, owing to the settlement in UE 147.[1/] In the end, there is no Commission precedent concerning prudence or the market value rule for Gadsby and West Valley.

Q. MR. TALLMAN HAS INCORPORATED PACIFICORP'S TESTIMONY FROM UE 134 INTO HIS REBUTTAL. DOES ICNU WISH TO INCORPORATE ITS UE 134 TESTIMONY INTO THE RECORD AS WELL?

A. For completeness of the record, I am including my direct testimony from UE 134 as Exhibit ICNU/112. Most of the information contained in my rebuttal testimony in UE 134 was condensed into my direct testimony in this proceeding, so I do not include it here.

[1/] At the time of the settlement in UE 147, the decision in UE 134 was still pending. In the UE 147 settlement, the parties agreed to drop the matter of West Valley in UE 134, without prejudice.

Q. MR. TALLMAN DISPUTES YOUR CONTENTION THAT PACIFICORP SHOULD HAVE SOUGHT BIDS TO REPLACE WEST VALLEY IN RFP 2003-A. ARE HIS ARGUMENTS PERSUASIVE?

A. No. In effect, Mr. Tallman is arguing that West Valley is a short-term resource (a three-year option) that should only be compared to other short-term options (i.e., as was done in RFP 2004-X).

This shows the fundamental problem of West Valley in that the Company simply *assumes* the prudence question away by defining West Valley as a "short-term" resource. Rather than comparing the resource to a long-term asset, the Company only compared it to short-term resources. I discussed how this biased the results of RFP 2004-X in my direct testimony. However, there is no basis for assuming that the Company actually needs "short-term" resources more than "long-term" resources in the first place, or for determining the optimal mix of long or short-term resources PacifiCorp should have in its portfolio. Likewise, Mr. Tallman does not offer any evidence to demonstrate that a long-term resource was not more economic than a plan with a "short-term" West Valley. It was purely arbitrary for the Company to make that designation in the first place. Mr. Tallman's response to this issue amounts to little more than saying, "West Valley is prudent because we say it is prudent."

Q. MR. TALLMAN CONTENDS THAT IT IS NOT PROPER TO COMPARE WEST VALLEY TO A "CURRANT CREEK CLONE" BECAUSE THERE WERE NO OTHER 2005 RESOURCES THAT BID WITH ECONOMICS COMPARABLE TO CURRANT CREEK. PLEASE COMMENT.

A. Mr. Tallman misunderstands my analysis. I compared the cost of West Valley to the combustion turbine portion of Currant Creek. There is nothing special about the Currant Creek combustion turbine that gives it a substantially lower cost than other resources. It provides a reasonable basis for estimating the cost of a replacement for West Valley.

Further, the Company itself could have built additional capacity at the Currant Creek site for an even lower cost, because it would have been an "incremental" unit. Thus, my estimate of the cost of replacing West Valley is a reasonable alternative for the Company to have considered.

Finally, there were other resources with overall costs that differed little from Currant Creek in RFP 2003-A. It was only the biased bid evaluation method used by the Company that made Currant Creek appear to be much more economical than the other options.

Q. ARE THERE POLICY REASONS WHY THE COMMISSION SHOULD NOT CONSIDER THE COMPANY'S REQUEST FOR A WAIVER IN THE CONTEXT OF THIS CASE?

A. The Commission should reject the request for waiver because it has not been appropriately raised in this case. Aside from the troubling procedural aspects of requesting a waiver from Commission rules at the "eleventh hour," the Commission should consider using the market value rule as a tool to protect Oregon's interest in situations involving new resources constructed in other states.

Q. PLEASE ELABORATE.

A. Under current law and practice, the Oregon Commission has little ability to address the construction of plants in other states. Currant Creek, for example, was certified in Utah, not Oregon. The Oregon Commission had no opportunity to approve or deny PacifiCorp's decision to build Currant Creek once it was certified. While the Commission always has authority to make a prudence disallowance in the context of a rate case, it can only do so in an "after the fact" proceeding. Even if a Commission questioned the prudence of a new plant, there is a natural reluctance to impose a disallowance on a plant after it has been completed. Judicious use of the "market value rule" would enable the Oregon Commission to pass judgment on new resources before construction begins. This would enable the Commission to ensure that only necessary and economical resources are added to the PacifiCorp mix.

Q. HOW WOULD THIS PROCESS WORK?

A. Ideally, the Company would file a case requesting a waiver from the market value rule at the time it files for certification of the resource. The Oregon Commission could then provide a waiver for new resources only if it agreed the new resources were needed, and were the least cost option. In this manner the Commission could play an active, rather than passive, role in the resource selection process. It could also provide a warning against plant construction in cases where prudence has not been demonstrated.

Q. WHILE YOUR PROPOSAL MAY BE INTERESTING, TO THIS POINT IT HAS NOT BEEN THE PRACTICE OF THE COMMISSION. PLEASE COMMENT.

A. True enough. However, this proposal is no more unusual than PacifiCorp requesting a waiver from the Commission's rule only after it has begun construction of a new power plant and requested rate treatment for it. Given the high financial stakes, it was imprudent for PacifiCorp to have begun construction of Currant Creek without first obtaining a waiver from the Oregon Commission. Effectively, the Company has taken full rate treatment from the state of Oregon for granted, in spite of the Commission's market value rule.

Q. WHAT DO YOU PROPOSE BE DONE NOW?

A. The Commission should follow the market value rule in this case.

Q. UNDER WHAT CONDITIONS SHOULD A WAIVER BE GRANTED?

A. The Commission should not grant a waiver from the rule unless it is satisfied that the new resources are needed and are the least cost option. The Commission should also determine if the bidding process used was reasonable, and whether it meets the Federal Energy Regulatory Commission's "above suspicion" standard in the case that the Company or its affiliates ended up as the "winning bidder." ICNU will elaborate on the legal aspects of the waiver issue in its briefs in this case.

Q. MR. WRIGLEY DISPUTES YOUR GADSBY CT ADJUSTMENT ON THE BASIS THAT CUSTOMERS WERE NEVER CHARGED FOR THE PEAKER RENTAL FEES THAT WERE SUBSEQUENTLY AVOIDED BY THE GADSBY CT PURCHASE FROM GENERAL ELECTRIC ("GE"). PLEASE COMMENT.

A. Whether ratepayers were charged or not for the rental fee is irrelevant. PacifiCorp chose its test years in various rate cases, and also chose to exclude the peaker rental fees from its excess power cost deferral (in UM 995). By making different choices, the Company might have been able to recover the peaker rental fees. However, the basis for my adjustment is tied to the fact that the Company would have saved itself $7.5 million through its negotiations with GE for the Gadsby CT equipment. Mr. Wrigley actually confirms that the Company stood to retain this amount because, at the time, the rental fees were not reflected in rates.

Q. MR. WRIGLEY TESTIFIES THAT PACIFICORP DID NOT HAVE A CONFLICT OF INTEREST IN ITS NEGOTIATIONS RELATED TO THE GADSBY TRANSACTION WITH GE. PLEASE COMMENT.

A. Mr. Wrigley's testimony is hardly persuasive. While he contends that PacifiCorp's interest was in getting "the best deal for customers," he offers no evidence as to what alternatives GE offered PacifiCorp. He only argues that GE might have preferred to waive the rental fee, rather than reduce the price of the peakers. He offers no evidence as to what GE's negotiating stance was, or whether it was GE or PacifiCorp who first made this proposal.

Q. HOW HAVE REGULATORS IN OTHER STATES ADDRESSED THIS ISSUE?

A. The last two Utah rate cases were settled, so there is no precedent established. However, the Utah Staff has supported a similar disallowance as shown in the following excerpt from the direct testimony of a Utah Division of Public Utilities ("DPU") witness in the most recent Utah rate case:

> **Q.** Please explain the Gadsby Lease Waiver Adjustment.
>
> **A.** When PacifiCorp applied for a certificate to build the Gadsby units in Docket No. 01-035-37, Company witnesses testified that the decision to build the combustion turbines at Gadsby was preferable over other available alternatives. J. Rand Thurgood testified for the Company that the Company's decision to install General Electric LM 6000 gas turbines was based in part upon: "…the economic benefit PacifiCorp and its customers would realize from General Electric's (GE) agreement to waive the additional fixed cost obligation to lease the temporary mobile gas turbines for another five months." Mr. Thurgood further testified that: "GE's agreement to release the Company from its lease obligation associated with an additional five months rental for the mobile gas turbines has a net impact of reducing 2002 operating expenses by $7.5 million. Simplistically, this has the impact of reducing the effective capital cost equivalent for this particular project to approximately $608/kW." When the Company compared the GE LM 6000 units with other alternative generating options for the Gadsby addition this amount was used.
>
> However the cost comparison provided by Mr. Thurgood showed that the $/Mwh cost of four other options was close enough to the selected GE LM 6000 alternative that they may have been competitively preferable for Utah ratepayers absent rate consideration for the $7.5 million offset to the capitalized cost of the GE LM 6000 units for the lease expense waiver. Therefore, when the Company wanted the Commission to approve their application to build the Gadsby units, they relied in part on the argument that the decision to construct the GE LM 6000 gas turbines would benefit ***both*** the Company and the ratepayers.
>
> The estimated construction cost of the Gadsby units was reduced by $7.5 million for the lease obligation payment waiver when comparisons were made with other competitive alternatives. However, in response to the Division's data request, PacifiCorp indicated that the $7.5 million in cost savings was not treated as a

> reduction in the capital cost of Gadsby in their rate application, they were treated as a $7.5 million reduction in the 2002 O&M expenses. The Utah ratepayers did not benefit from the GE lease payment waiver. PacifiCorp's rates at that time were determined in Docket No. 01-035-01. The expenses associated with the GE lease were outside of the test period and no adjustment was made to include them for rate-making. While the Company may argue that absent the waiver, PacifiCorp would have had $7.5 million more in net power costs in that case test period, other parties could have persuasively argued that such costs were one-time non-recurring costs which should be excluded from rate-making.
>
> Therefore, contrary to the Company's assertion that the lease payment waiver benefited both the Company and the Utah ratepayers, it appears that only PacifiCorp stockholders benefited from the arrangement based on the Company's filing.
>
> In my opinion it would be equitable to reduce the rate base amount approved for the Gadsby units by the Utah allocated portion of the current value of the $7.5 million cost reduction, consistent with the way the Company recognized the amount in comparing alternatives in making the decision to purchase the GE LM 6000 units. In this way the rate reduction will continue as long as the costs associated with Gadsby are recovered in rates from Utah ratepayers, and consequently Utah ratepayers will benefit from the lease waiver consistent with the Company's arguments when the Commission approved the certificate to build the units.

Re PacifiCorp, UPSC Docket No. 04-035-42, Direct Testimony of Bruce Scott Moio at 2-4 (Dec. 3, 2004) (internal citations omitted). Mr. Moio's arguments are reasonable and provide another basis for the Commission to adopt the proposed disallowance.

GP Camas Contract

Q. MR. WRIGLEY NOTES THAT YOUR GP CAMAS ADJUSTMENT DIFFERS SLIGHTLY FROM THAT PROPOSED BY STAFF AND THE COMPANY. PLEASE COMMENT.

A. I accept the figures of Staff witness Breen and PacifiCorp witness Wrigley on this adjustment.

RVM Issues

Q. MS. OMOHUNDRO GENERALLY DISPUTES YOUR CONTENTION THAT AN ANNUAL RVM IS NOT NECESSARY. PLEASE COMMENT.

A. Ms. Omohundro never spells out any specific problems that would result if there was not an annual RVM. Her testimony is rather vague and uninformative on this issue.

Q. MS. OMOHUNDRO TESTIFIES THAT PACIFICORP INTENDS TO MINIMIZE THE WORKLOAD OF PARTIES. SHE CONTENDS THE PROPOSED RVM IS "LARGELY MECHANICAL" AND PATTERNED AFTER PGE'S RVM MODEL. PLEASE COMMENT.

A. PacifiCorp might hope that its RVM will be a "mechanical" exercise. However, experience with PGE has shown that a great number of issues can arise in the RVM setting, including propriety and eligibility of costs, scope of the RVM, modeling techniques, and prudence. There is no reason to expect that PacifiCorp's RVM will be any less complex than PGE's. In fact, given that PacifiCorp is a much larger and more complex system, and that it operates in six states, any annual RVM is likely to be far more complex than PGE's.

Further, PacifiCorp has actually increased the burden on intervenors and the Staff by patterning its RVM too closely after PGE's. Based on discussions held during recent workshops, it appears that the Company is still proposing an annual RVM schedule quite similar to PGE's RVM schedule. This means that parties will have the complexity of dealing with two RVM cases at the same time. While Staff, CUB, and ICNU will have two RVM filings to deal with, PacifiCorp (and PGE) will only be concerned with one. This will certainly make it more difficult for the parties to fully explore all of the issues that impact ratepayers.

Q. MOST OF THE POWER COST ISSUES RELATED TO PACIFICORP'S INITIAL FILING WERE SETTLED. DOES THIS SUGGEST THAT FUTURE RVM CASES WILL BE "LARGLY MECHANICAL," AS SUGGESTED BY MS. OMOHUNDRO?

A. No. In fact, quite the opposite is likely to be true. In future RVM proceedings, power cost issues settled in this case may be litigated again. The Partial Settlement does require the Company to make a deduction from its RVM updates in this proceeding, but future cases will likely see a number of the same types of issues litigated. Had the stipulation addressed specific adjustments, there would likely be fewer disputed issues to resolve in future cases.

Q. MR. WIDMER TESTIFIES THAT IN UM 1081, "MARKET EVEN" MERELY MEANT THAT THERE WAS NO TRANSMISSION ADDER USED IN THE COMPUTATION OF THE TRANSITION ADJUSTMENT. PLEASE COMMENT.

A. The Commission can determine what it meant by "market even" better than Mr. Widmer or I. However, if the Commission's goal was to provide a transition adjustment equal to the market value of the freed up resources, the PacifiCorp calculation does not do so. The Company proposes a transition adjustment based on its Generation and Regulation Initiatives Decision Tools ("GRID") model that, as shown on page 51 of my direct testimony, is lower than the cost of standard market products. What the Company has computed is *not* the market value of the freed-up resources, but rather the value to PacifiCorp of the freed-up resources. Because the Company maintains that it already is unable to sell all of its coal-fired capacity off peak, it concludes that the value of the power in GRID is less than the value of standard products. But, one must ask, why is it then that the cost of standard products always exceeds their value to PacifiCorp? This is a contradiction that must be resolved.

Q. PLEASE EXPLAIN.

A. The Company is suggesting that it is prudent for it to buy 25 MW of a standard product in the market place at a price of $46.38/MWh to serve a 25 MW load. However, if the same 25 MW of load leaves the system for direct access, then the value of the resold power is only $43.68/MWh. The reason is that during the "graveyard shift" the Company cannot resell the product that is no longer needed because there is no market for it, and its coal units would have to be backed down instead. That being the case, one must ask why standard product prices are as high as they are, when there is energy that is virtually "dirt cheap" in the graveyard hours? I can think of three possible explanations.

First, it is possible that the market is not efficient. Ordinarily, one would expect that, if PacifiCorp has idle coal-fired generation in the graveyard shift, then market prices should drop to the cost of coal-fired energy. If it does not, then the market is not efficient. The question then becomes, why should departing loads be assessed the cost of an inefficient market?

Second, it is possible that the GRID model logic or the market cap inputs are seriously flawed. This is possible because PacifiCorp has computed the market caps based on historical data for balancing transaction volumes. However, historically PacifiCorp transacted a substantially greater amount of short-term firm ("STF") transactions than are modeled in GRID. In fact, PacifiCorp excluded 77% of its typical STF transaction volume in GRID because it used only transactions arranged before the filing date. Thus, the size of the total market (both balancing plus STF contracts) has historically been much larger than the Company is assuming in this case. Because of this, the Company is really modeling a much smaller market in GRID than exists in reality.

Finally, the problem may lie with the shaping of standard product prices into hourly prices used by the Company. The Company develops its hourly market prices in GRID based on hourly price patterns derived over many years. To the extent that prices in the earlier years (i.e., the late 1990s) had prices that were much lower than today, with much different shapes, it's possible that the shaping factors used by the Company simply do not reflect current market conditions. Because of this, the prices modeled in the graveyard shift may be higher than current market prices, while prices in other hours may be lower than they should be.

For these reasons, the entire issue of market caps may be a "red herring." Until this can be resolved, I believe it would be wiser for the Commission not to rely on GRID for the transition adjustment modeling.

Q. MR. WIDMER DISPARAGES YOUR TESTIMONY CONCERNING THE ISSUE OF MARKET CAPS ON THE BASIS THAT THIS ISSUE WAS NOT INCLUDED IN THE LIST OF RESERVED ISSUES IN THE PARTIAL STIPULATION. PLEASE COMMENT.

A. First, I am not proposing any market cap adjustment to Net Power Costs or any correction to the market cap adjustment proposed in the Partial Stipulation. Thus, there is no basis for Mr. Widmer's comments. My proposal is to compute the transition adjustment, without the use of GRID, owing in part to problems with the market cap modeling as it impacts the transition adjustment calculation. I do not believe Mr. Widmer, or other parties, dispute ICNU's right to propose an alternative to GRID for computing the transition adjustment.

Q. MR. WIDMER DISPUTES YOUR TRANSMISSION COST ADDER ON THE BASIS THAT TRANSMISSION CONTRACTS ARE FIXED AND NOT AVOIDABLE. DO YOU AGREE?

A. This argument goes to the level of the adjustment, not to its merit. Mr. Widmer has presented no alternative. Further, even if existing transmission contracts are fixed for a number of years, as load grows, undoubtedly additional transmission will be required and be more costly than existing contracts. Thus, my calculation of the average transmission cost per MWh is probably conservative.

<u>Other GRID Issues</u>

Q. MR. WIDMER DISPUTES YOUR DEFERRAL PERIOD OUTAGE ADJUSTMENT. HE CONTENDS THAT THERE IS "NO DOUBLE COUNT" OF DEFERRAL PERIOD OUTAGES BECAUSE IN THIS CASE, THE COMPANY IS ONLY SEEKING TO RECOVER THE NORMALIZED COST OF OUTAGES. DO YOU AGREE?

A. No. Mr. Widmer has included all of the outages that occurred during the deferral period (except Hunter) in his calculation of outage rates. He did so, in his own words, because "*The Company's outage rate modeling is simply a four-year amortization of outage costs*." <u>Re PacifiCorp,</u> WUTC Docket No. UE-032065, Rebuttal Testimony of Mark Widmer at 37 (July 28, 2004). Because the outage rate modeling he proposes is intended to provide a four-year amortization of the very same costs being recovered in the UM 995 deferral, it is a double count.

Q. MR. WIDMER CONTENDS THAT THE HUNTER OUTAGE WAS REVERSED FROM THE OUTAGE RATE CALCULATION BECAUSE IT WAS AN EXTRAORDINARY OUTAGE. IS THIS CONSISTENT WITH HIS PRIOR TESTIMONY?

A. No. In this case, Mr. Widmer testifies that:

> In contrast to the other outages, the length of the Hunter 1 outage was much greater than the normal level included in retail rates, so there was an incremental impact, which resulted in deferral and recovery.

PPL/609, Widmer/3. In UE 147, Mr. Widmer testified that:

> Because the Company is recovering the cost of the catastrophic Hunter unit 1 outage through the treatment adopted in UM 995, the Company has excluded that outage from its 48-month outage calculation.

Re PacifiCorp, OPUC Docket No. UE 147, PPL/500, Widmer/12 (Mar. 19, 2003).

In other words, in UE 147, Mr. Widmer merely acknowledged that the Hunter outage costs were already being recovered, while in the current case he is arguing that it should be reversed because it was much more significant than other outages, resulting in a deferral.

Q. MR. WIDMER TESTIFIES THAT THERE IS NO DOUBLE COUNT OF OTHER OUTAGES IN THE DEFERRAL BALANCE. IS HE CORRECT?

A. Mr. Widmer testifies as follows:

> UM 995 excess net power costs were calculated as the difference between actual net power costs and net power costs included in rates. For example, if net power costs in rates were $500 million and actual net power costs were $700 million, the excess net power cost deferral would have been $200 million. In other words, the Company was collecting the normalized level of outages and market prices as part of net power costs in base rates *and collected the recoverable portion of excess outages and market prices as part of excess net power costs through a separate surcharge*. In this case, the Company is only requesting recovery of normalized costs, so there is no double count with costs related to the UM 995 deferral period.

PPL/609, Widmer/3 (emphasis added).

This passage is purposefully misleading. *All* outages result in increases in power costs. Thus, the $700 million actual power costs in his example is a product of various factors, including *all* of the actual outages. Had the Company had fewer outages, the $700 million figure would be lower. If the Company had no outages, the actual power costs might be only $600 million in this example. In that case, the deferral would be $100 million, not $200 million. Consequently, the extra $100 million is completely attributable to outages, and that cost is what is being recovered via the deferral. In this case, there is absolutely no difference between the Hunter outage and other outages, aside from its magnitude. Every single outage that occurred increased actual power costs, and thereby resulted in a larger deferral balance. Consequently, customers are paying for the costs of all actual outages already in the surcharge. There is simply no basis for an additional "*four-year amortization of outage costs*" as part of the calculation of outage rates.

Q. MR. WIDMER CONTENDS THAT IF OTHER OUTAGES WERE REMOVED IN THE SAME MANNER AS THE HUNTER OUTAGE WAS REMOVED, POWER COSTS WOULD INCREASE SUBSTANTIALLY. DO YOU AGREE?

A. No. Mr. Widmer's testimony on this point is completely misleading to the Commission. The analysis he performs does not do what he says it does. He does not treat other outages the same way as Hunter; he treats them in a much different way. In fact, he does not even treat the Hunter outage in the same way in the two calculations. Therefore, his analysis and his claims are simply false.

Q. PLEASE EXPLAIN.

A. In Mr. Widmer's original filing (and his updates), he reversed the five-month Hunter outage by removing it from the 48-month outage rate calculation. He did so by effectively calculating the outage rates for the period of time when Hunter was not on outage (or the remaining 43 months). Thus, Mr. Widmer excluded from the outage rate calculation only the period of time that the major outage occurred. One could argue about whether this approach also overstates costs, but that was his approach and I used it for all outages in my analysis.

Q. HOW DOES THIS DIFFER FROM HIS NEW ANALYSIS, WHERE HE CLAIMS TO HAVE REMOVED OUTAGES DURING THE DEFFERAL PERIOD?

A. In his new analysis, he now removes the entire ten-month period from the outage rate calculation. This is completely arbitrary, particularly in light of the fact that he has previously argued in favor of a 48-month period. In his new analysis, he now reverses the Hunter outage by removing Hunter for ten months from his outage calculation, rather than the five months he removed previously. His claim that he is treating all outages in the same manner as the Hunter outage is false. He does not even treat the Hunter outage the same as he did in his original GRID studies, because now he computes the Hunter outage rate based on a 38-month period, while earlier he computed it based on a 43-month period. He is doing nothing more than playing a "numbers game" to confuse and mislead the Commission.

Q. COMPARE THIS TO YOUR OUTAGE RATE CALCULATION.

A. In my calculation I did treat all of the outages exactly like the Hunter outage. For example, if a unit had an outage that lasted one month during the deferral period, then I computed the outage rate for that unit based on excluding that month alone, just as I computed the outage rate for Hunter by excluding the five-month period from the calculation. Because the other outages that occurred in the period were no different from the Hunter outage, there is no reason they should be treated any differently in the calculation of outage rates for GRID. In Mr. Widmer's calculation, it would make no difference to the final outage rates if a unit was out of service for the entire deferral period or not at all. Now, should the Commission believe that if a unit were on outage for the entire deferral period, it would have had no impact on the level of the deferred costs? Obviously not! Because Mr. Widmer has presented a false analysis to the Commission, his testimony on this issue should be rejected.

Q. MR. WIDMER DEFENDS HIS RAMPING AND STATION SERVICE ADJUSTMENTS BASED ON SEVERAL CRITICISMS OF YOUR GRID RUN USING HISTORICAL LOADS. PLEASE COMMENT.

A. Mr. Widmer contends that my run using historical loads and hydro levels was incomplete because I did not adjust for a variety of other items that are changed in the current GRID model. To address this issue, there are two approaches that might be used. First, the Company could do a historical "backcast." In this analysis, an attempt is made to recreate historical results, using actual data in the model. If such a study showed that GRID produced too much coal-fired generation compared to what actually happened, he might have a point. However, he has not provided such a study in this case.

Q. HAS PACIFICORP EVER PERFORMED A BACKCAST USING GRID?

A. Yes. In UE 147, the Company provided me an analysis of a historical backcast comparing GRID to actual results for the period October 2001 to September 2002. I have attached an excerpt of this study as Exhibit ICNU/113. In the analysis, the Company contended that GRID predicted power costs within 0.1% of actual. Further, the Company's analysis showed that thermal generation was 1% less than actual, and that GRID predicted coal fired generation 0.7% less than actual. This analysis does not support the conclusion that GRID is producing too much coal-fired generation. Indeed, it supports the opposite conclusion, that if anything, the model was under-predicting thermal generation long before the station service and ramping adjustments were made. This undermines Mr. Widmer's entire basis for the ramping and station service adjustments

Q. ASIDE FROM THE BACKCAST, ARE MR. WIDMER'S CRITICISMS OF YOUR GRID MODEL RUN REASONABLE?

A. No. Mr. Widmer has concluded that because GRID shows more coal-fired generation than historically occurred, there must be something wrong with the model, requiring ad-hoc manipulation of the inputs. However, an equally valid assumption would be that the system has changed, resulting in an increase in coal-fired generation. Given the substantial increase in loads predicted by the Company, the simplest explanation is that the increased loads are resulting in increased generation. Mr. Widmer has done nothing to determine whether the latter explanation is plausible. That is what my GRID study using historical load data accomplished. My goal was not to perform a historical benchmark, but rather to show the extent to which the increase in loads over historical levels might impact actual coal-fired generation. My analysis showed that a substantial increase in coal-fired generation may occur if a substantial increase in loads occurs. Given that coal-fired generation is much lower in cost than market purchases, one would intuitively expect that as load increases, the Company will first increase its output from coal plants. Mr. Widmer would have the Commission believe that no matter how high loads become, coal-fired generation will remain constant.

Q. DO MARKET CAPS HAVE A BEARING ON THIS ISSUE?

A. Certainly. Because of the market caps, the Company cannot sell all of its idle coal-fired capacity during the graveyard shift. However, if load increases, the Company will then be able to increase the utilization of the otherwise idle coal-fired capacity. This will result in an increase in coal-fired generation over historical levels. Mr. Widmer has completely ignored this fact in his testimony.

Q. COMMENT ON MR. WIDMER'S CONTENTION THAT THE UE 139 DECISION REJECTING A SIMILAR ADJUSTMENT BY PGE IS NOT APPLICABLE TO PACIFICORP.

A. Mr. Widmer is wrong. In UE 139, the Commission rejected an ad-hoc data manipulation to address a speculative "problem." Instead, the Commission continued to rely on industry standard modeling methods. Mr. Widmer has not even demonstrated that the "surplus" of coal-fired generation really exists in GRID. Instead, he justifies his entire analysis on a flawed comparison of historical coal generation to current GRID studies. He has not shown that a historical backcast of GRID over-predicted coal-fired generation in the past, nor does he show that the current system configuration and loads would not result in increased coal-fired generation. The UE 139 precedent is on point, because in that case, the Commission correctly rejected result-oriented data manipulation to solve a problem that was never proven to exist.

Q. MR. WIDMER DISPUTES YOUR RECOMMENDATION TO REVERSE HIS DEFERRED MAINTENANCE ADJUSTMENT ON THE BASIS THAT GRID OVER-PREDICTS OFF-PEAK GENERATION. DO YOU AGREE?

A. No. Despite anything Mr. Widmer claims to show concerning when these outages occur, it does not change the fact these outages are *deferrable*. Therefore, they do not need to be scheduled during hours when market prices are at their peak. His adjustment would ignore this fact, and schedule deferrable outages at any time, even the highest priced hours.

Q. MR. WIDMER CLAIMS, ON THE BASIS OF PPL/610, THAT ONLY 49% OF GENERATION LOST DUE TO MAINTENANCE OUTAGES OCCURS DURING LIGHT LOAD HOURS ("LLH"). PLEASE COMMENT.

A. Mr. Widmer's calculation is quite questionable because the amount of lost generation he has computed for LLH and Heavy Load Hours ("HLH") substantially differs from the amount of total lost generation that occurred during the four-year period. Mr. Widmer did not supply complete workpapers, so it is not possible to discern the cause of this discrepancy. More significantly, Mr. Widmer has confused the issue. Prior to the deferred maintenance adjustment, maintenance outages in GRID occurred during the 56-hour weekend period. However, his analysis counts 16 HLH hours that occur on Saturdays. Therefore, PPL/610 does not really provide an accurate indication of the best method to apply in GRID because it includes weekend hours.

Q. MR. WIDMER CONTENDS THAT THE FIGURE REFERENCED ON PAGE 47, LINE 7 (68.5%) OF YOUR DIRECT TESTIMONY IS WRONG. PLEASE COMMENT.

A. I incorrectly stated in my direct testimony that 68.5% of the energy lost due to maintenance outages occurs during LLH. I should have pointed out that I counted the entire weekend along with the LLH hours during weekdays. This is appropriate, however, because we are trying to decide whether to include the maintenance outage on the weekend or not. My analysis shows that 68.5% of all energy lost due to maintenance outages occurs during LLH during the week or on the weekend. By modeling maintenance outages as part of the weekend outage rate, 71% of the energy would be lost in LLH, and 29% would be lost in HLH hours, which is quite close to the actual data. Clearly, it makes more sense to model these outages as part of the weekend outage rate, rather than to assume they occur during all hours, including peak price periods.

Q. MR. WIDMER CONTENDS THAT A SEASONAL MODELING OF MAINTENANCE OUTAGES, AS SUGGESTED IN YOUR TESTIMONY, WOULD RESULT IN HIGHER POWER COSTS. PLEASE COMMENT.

A. Mr. Widmer is distorting my testimony. I never proposed a seasonal modeling of these outages. I merely pointed out that far less energy is lost during peak months than off-peak months, because these outages are deferrable. In the end, Mr. Widmer wishes to ignore the fact that deferrable outages can be scheduled at times (whether LLH or HLH, weekend or weekdays) when market prices are lowest.

Q. MR. WIDMER DEFENDS HIS PROPOSAL TO CHANGE FROM THE COMMISSION'S ACCEPTED PROCEDURE THAT BASES SCHEDULED MAINTENANCE ON THE 48-MONTH AVERAGE. PLEASE COMMENT.

A. Mr. Widmer is advocating that the Commission abandon established practice to gain a small advantage for the Company. His argument that PacifiCorp should be allowed to use this approach because PGE does so is unsound. First, PGE has a Commission-approved RVM resulting from a stipulation among the parties. There is no such agreement among the parties in this case.

In addition, PGE has only one large coal plant, which is critical in determining its power costs. In a given year, whether or not major overhauls are performed can have a substantial impact on power costs. By using the actual schedule, PGE may be better able to predict power costs for the next year. However, should PGE change its maintenance schedule after the RVM filing, that could impact power costs substantially. Because maintenance schedules can change, the use of a 48-month average maintenance schedule for PGE would also be reasonable so long as a consistent approach is followed.

In contrast, PacifiCorp has a large number of coal-fired generators, and it is likely that the major overhaul cycles of various units will balance out over time. Further, past experience has shown (as in the case of the Hunter outage, for example) that PacifiCorp can and does change maintenance schedules. Thus, the year-ahead maintenance forecast is unlikely to be followed in actual practice. Given the history of using the 48-month average for PacifiCorp, and in light of all these factors, I continue to recommend use of the 48-month average instead of the currently forecast schedule.

Q. MR. WIDMER DISPUTES YOUR RECOMMENDATION THAT THE 48-MONTH HISTORICAL DATA PERIOD BE CHANGED. HE CONTENDS THAT ICNU WAS GIVEN THE CHOICE OF FILING ITS TESTIMONY CONCERNING THE MARCH 15, 2005 UPDATE WITH THIS SURREBUTTAL TESTIMONY. PLEASE COMMENT.

A. I am not disputing Mr. Widmer's statements. However, Mr. Widmer did not explain why ICNU turned down this "offer." His proposal was for ICNU to file its comments regarding the updates to GRID with ICNU's surrebuttal testimony. However, the Company would then have had the opportunity to respond to our testimony in its later "sur-surrebuttal" testimony. As this would have denied ICNU the opportunity to put in any response to the Company's defense of his proposed adjustments (as I am now presenting here), we filed our initial comments in ICNU's direct testimony. We believe the record is better served by this approach, even if it did provide ICNU with less time to prepare its case.

In any case, this episode clearly illustrates ICNU's concerns about the proposed RVM process. While the stakes are nearly as high as a full-blown rate case, the "schedule" is very short, extremely fluid, and subject to the whims and abuses of the Company. This provides yet one more reason to reject the annual RVM proposed by the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 134

In the Matter of	)
	)
PACIFICORP	)
	)
Application for Approval of Revised Tariffs	)
to Reflect New Net Power Costs.	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

January 6, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have more than 20 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, plus as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear power plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, West Virginia and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc., with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I filed testimony in PacifiCorp's ("PacifiCorp" or the "Company") last two rate proceedings in Oregon (Docket Nos. UE-111 and UE-116). Both cases were ultimately settled on the issues I addressed. In those cases, I addressed issues related to modeling of net power costs, and a Power Cost Adjustment ("PCA") mechanism. I also filed testimony in PacifiCorp Docket No. UM-995, quantifying the disallowances proposed by other ICNU witnesses and the costs of the recent hydro energy deficit experienced by the Company. In addition, I submitted testimony on behalf of ICNU in two recent Portland General Electric ("PGE") dockets. In Docket No. UE-137, I filed testimony regarding PGE's request for a PCA for 2003. PGE ultimately withdrew that request. In Docket No. UE-139, I filed testimony proposing certain adjustments to PGE's annual update to its Schedule 125 Resource Valuation Mechanism.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING PACIFICORP?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Utah and Wyoming, where I testified concerning power cost issues. I also appeared in the Gadsby Combustion Turbine ("CT") Certification proceeding in Utah (Utah Public Service Commission ("UPSC") Docket No. 01-035-37). Exhibit ICNU/101 summarizes other cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to comment on the following two issues established for examination in this proceeding in Commission Order No. 02-820, dated November 20, 2002:

1. Is the cost of the West Valley lease ("West Valley Lease" or the "Lease") a necessary and ordinary recurring expense?

2. Does permitting recovery of the full cost of the Lease violate OAR § 860-038-0080(1)(b)?

Q. PLEASE STATE YOUR UNDERSTANDING OF THESE QUESTIONS, FROM THE PESPECTIVE OF REGULATORY POLICY.

A. The first issue concerns the traditional ratemaking standard of prudence. For this case, I would equate necessity with prudence. Only the least cost alternative represents a necessary or prudent cost, because higher cost alternatives are, per-se, not necessary or prudent.

The second question concerns the implementation of OAR § 860-038-0080(1)(b), which provides:

> The Commission will not require an electric company to acquire new generating resources except as provided in ORS 757.663. Major capital improvements to existing generating resources will continue to be subject to least cost planning processes and analyses and the Oregon share of their prudently-incurred costs will be included in an electric company's Oregon revenue requirement, which for a multi-state electric company shall be consistent with Commission decisions pursuant to subsection (3)(a)(G) of this rule. *Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company [.]*

OAR § 860-038-0080(1)(b) (emphasis added). The italicized section of the code is the part most applicable to this proceeding. This language prohibits the cost of new resources from being included in rate base. Instead, new resources must be included in revenue requirements at market prices. This rule implies that new resources should be reflected in revenue requirement at current market prices, rather than actual cost.

Q. WHAT ARE YOUR CONCLUSIONS?

A. I have concluded as follows:

Necessity of the West Valley Lease

1. The West Valley Lease is not a necessary or prudent cost.

2. The Company failed to adequately compare the cost of CT ownership to the cost of the Lease. The Lease costs more than ownership of the same resources.

3. The West Valley project (“West Valley Project” or the “Project”) is a very expensive CT technology. Larger facilities, located at lower altitude, would have been more economic and should have been considered. PacifiCorp only obtained

West Valley due to a pressing short-term need for power. The Company should have examined other, more economic options at an earlier time.

4. The ancillary services and transmission benefits applicable in the case of the Gadsby CT are not applicable to West Valley. While the technology is the same, the Company does not need additional capacity to provide these ancillary services.

5. The operational inflexibility of the Project causes PacifiCorp's net power costs to increase (rather than decrease) based on runs of PacifiCorp's hourly power cost model, the Generation and Regulation Initiatives Decision Tools ("GRID"). This demonstrates that the Project was not prudent and that the cost of the Project exceeds market values, even without the Lease payment.

OAR § 860-038-0080(1)(b) Issues

6. It appears that a major motivation of the Lease may have been to circumvent the requirements of OAR § 860-038-0080(1)(b). Inclusion of the West Valley Lease payment in rates will amount to recovery of exactly the same kinds of costs that are forbidden under the law. This is particularly suspect given that PacifiCorp entered into the Lease with its affiliate, PacifiCorp Power Marketing ("PPM").

7. Purchased power prices collapsed shortly before PacifiCorp issued its Request for Proposals ("RFP") in September 2001, and continued to decline during the evaluation period. Given the recent history of Western US power prices at the time PacifiCorp issued the RFP, bidders obviously would have been reluctant to make offers reflecting changed market conditions. As a result, the cost of the West Valley Lease was above market at the time PacifiCorp executed the Lease. Given the circumstances, PacifiCorp should have sought new bids prior to executing the Lease.

8. An analysis performed by PacifiCorp in the current Wyoming rate case demonstrates that the cost of the West Valley Project exceeds market value.

9. As a result of these findings, the cost of the West Valley Lease should not be included in customers' rates.

III. THE ISSUES OF PRUDENCE OR NECESSITY

Q. IS THERE A DISTINCTION BETWEEN THE ISSUE OF NECESSITY OF COSTS AND PRUDENCE IN THIS CASE?

A. No. In the context of this case, I believe the prudence and necessity of costs are the same thing. A cost that is not necessary is, per-se, imprudent.

An extreme example might be the purchase of a $500 hammer instead of a $10 hammer. While a hammer might legitimately be needed, the cost is so excessive that the expenditure cannot possibly be considered prudent. The extra $490 represents *unnecessary* or *imprudent* costs.

Likewise, with respect to the West Valley Lease, ICNU is not questioning whether the capacity of the Project (or some other resource) may have been needed in the summer of 2002. The question is whether the West Valley Lease, as structured, was the least cost alternative available.

In its "issues list" list submitted in this proceeding, ICNU's first proposed issue was: "Are the costs of the West Valley Lease prudent?" The Administrative Law Judge ("ALJ") framed the issue as whether these costs were a "necessary and ordinary recurring expense." However, in Order No. 02-820, the Commission concluded that "the first issue identified by ICNU is the same issue, in different words, that the ALJ set forth in her memorandum." Re PacifiCorp, Docket Nos. UE-134 and UM-1047, Order No. 02-820 at 7 (Nov. 20, 2002). Thus, the first issue in this proceeding is whether the costs of the West Valley Lease are prudent.

Q. DO YOU BELIEVE THAT THE WEST VALLEY LEASE WAS A PRUDENT RESOURCE SELECTION FOR PACIFICORP?

A. No. There are a number of troublesome issues that concern me. These issues raise "red flags" concerning the question of prudence.

First, I don't believe the Company ever performed a valid examination of the economics of owning the West Valley Project versus leasing the Project. The

Application filed by PacifiCorp in Docket No. UI-196 alleged that the Lease option was lower in cost than ownership of the same resources:

> Significantly, the lease payment amount for this resource (i.e. $6.13/kW-month) is slightly lower than the projected cost (when utilizing similar amortization periods and after normalizing for differences in project capacity amounts) of a gas-peaking generation plant using identical turbines installed at an existing generation site (i.e., $6.32/kW-month).

Re PacifiCorp, Docket No. UI-196, Application at 10 (Mar. 6, 2002).

PacifiCorp's analysis of the ownership option was exceptionally flawed and overly simplistic. *See, e.g.*, Exhibit ICNU/102 (a copy of the economic analysis of the Lease provided by PacifiCorp in UI-196). The problem with PacifiCorp's analysis is that the Lease terminates after fifteen years, while outright ownership of the plant would last for the life of the facility. The PacifiCorp analysis justifying the Project fails to consider this very important fact.

Q. CAN YOU PROVIDE AN ANALOGY THAT ILLUSTRATES THIS PROBLEM?

A. Yes. This situation is really no different than the typical buy versus lease decision facing a person shopping for a new car. While a lease may have lower payments, it is incorrect to compare a lease payment to a conventional car payment. An astute car buyer must recognize that, at the end of the car payments, the person owns the car. At the end of the lease payments, the person returns the car. The car shopper must consider the *residual value* of the car in the purchase option to make the most economic decision.

Effectively, the Company biased its analysis by assuming that, in the ownership case, the cost of the CTs would be amortized over 15 years (the same term as the Lease), but the facility would have no residual value at that time. This was very unrealistic. The prices of CTs have typically increased over time, and CTs have a useful life of at least 25 years. At the end of the 15 years, it is reasonable to assume the Project would have a residual value equal to the market value of a new CT, with a deduction for the shortened remaining life.

Q. WHAT DOES A CORRECTED OWN VERSUS LEASE ANALYSIS SHOW?

A. Exhibit ICNU/102 shows that once the residual value of the CTs is factored in, there would have been a definite advantage to ownership instead of a lease. In fact, the Lease costs about 20% more than ownership of the same resource.

Q. THE LEASE DOES ALLOW THE COMPANY TO PURCHASE THE PROJECT IN EITHER YEARS THREE OR SIX OF THE AGREEMENT. DOES THIS MITIGATE THE PROBLEMS WITH THE LEASE OPTION VIS-À-VIS OWNERSHIP?

A. Not really. First, the Company is obligated to the transaction for three to six years, and is paying the higher costs for that period of time. Second, as I demonstrate below, the cost of the West Valley CTs is extremely high compared to other types of peaking plants. Thus, there would likely be no advantage to PacifiCorp in owning this high cost facility. As a result, I question whether it would make economic sense to exercise the purchase option.

Q. IS AN OWN VERSUS LEASE ANALYSIS RELEVANT IF NEW RESOURCES WILL BE PLACED IN RATES AT MARKET PRICES?

A. Yes, for several reasons. First, the ownership option is an indicia of market value for this type of resource. Second, a utility must demonstrate that it chose the least cost option in order to demonstrate prudence. Third, the Commission's transfer pricing policy between affiliates requires that a utility's purchase from an affiliate be at the *lower* of cost or market. Re Pacific Power and Light Co., Docket No. UI-114, Order No. 91-1248 (Sept.

24, 1991). Finally, as discussed later in my testimony, the Lease is structured to provide rate base-like treatment of the costs of the West Valley Project. Therefore, it is appropriate to evaluate an ownership alternative in determining prudence.

Q. WHAT IS YOUR CONCLUSION REGARDING THE ISSUE OF LEASING VERSUS OWNERSHIP OF WEST VALLEY?

A. The Lease payment is not a necessary expense because it was not the least cost means of acquiring the resources.

Q. WHY DO YOU THINK THAT PACIFICORP CHOSE THE LEASE STRUCTURE?

A. It seems quite possible that the Company may have decided to use the Lease transaction as a means of circumventing the requirements of OAR § 860-038-0080(1)(b). OAR § 860-038-0080(1)(b) creates a prohibition against inclusion of the cost of a new resource in rate base. The Company may have feared that it would not be able to obtain recovery for the cost of a new plant under the traditional return on rate base methodology. However, the Company attempted to treat the West Valley Lease as an operating expense in UE-134. This may have been an attempt to circumvent the requirements of OAR § 860-038-0080(1)(b). In any case, the issue of the Lease is properly considered in this case in the context of the market prices for the power from the Project, as I will discuss later.

Q. WHAT OTHER PRUDENCE CONCERNS DO YOU HAVE WITH RESPECT TO THE WEST VALLEY PROJECT?

A. My <u>second</u> major prudence concern is the extremely high cost of this type of facility. Irrespective of whether the Company should have leased or owned the resource, it is undeniable that this is an extremely costly CT. Based on the PacifiCorp analysis discussed above, the Company views the cost of West Valley to be comparable to the Gadsby CTs. The figures shown in Exhibit ICNU/102 imply an installed cost of $666/kW for West Valley. This is substantially higher than traditional CTs, which the Company has typically assumed to cost $400-$500/kW in its Integrated Resource Plan ("IRP") process. It is also much higher than the prices typically assumed by analysts for new CTs. For example, in market price forecasts I prepared in previous stranded cost litigation, I typically assumed costs for new CTs in the range of $300-$350/kW. I was frequently criticized by other experts for using "high" figures.

Q. WHAT IS THE CAUSE OF THIS HIGH COST?

A. There are a number of factors. First, the West Valley Project has five 40 MW units. Units of this small size have a higher installed cost per kW, than larger modern frame-type CTs. Thus, the West Valley plant does not take advantage of economies of scale.

Second, the West Valley units are LM-6000 aero-derivative CTs. As the name suggests, this type of unit is based on modern jet engine technology. While this provides quick start benefits, it also greatly increases the cost. The Company has not demonstrated the benefits of the higher cost of West Valley relative to lower cost frame units.

Third, the location of the West Valley Project at high altitude reduces the maximum plant output. Location of CTs at a lower altitude site (in Oregon or elsewhere) would result in a lower cost per kW of effective capacity.

For all these reasons, the cost of the West Valley Project was unnecessarily high. The Company has not demonstrated that West Valley was a lower cost resource than a conventional CT at a more attractive site.

Q. WHY DO YOU BELIEVE THE COMPANY WAS WILLING TO ACCEPT SUCH A HIGH COST RESOURCE?

A. During the Gadsby CT certification proceeding in Utah (UPSC Docket No. 01-035-37), the Company indicated it had a pressing need for capacity in the summer of 2002. The Company intended to address this looming shortfall by building the Gadsby CT and leasing the West Valley Project.

Q. YOU MENTIONED THE GADSBY CT CERTIFICATION CASE. WHY DID YOU RECOMMEND CERTIFICATION OF THE NEW GADSBY FACILITY, WHICH HAS IDENTICAL LM-6000 CTS, WHILE YOU NOW DISPUTE THE BENEFITS OF THE WEST VALLEY PROJECT?

A. My recommendation of the Gadsby project was based on my acceptance of the alleged need for capacity in the summer of 2002. However, I conditioned my recommendation by stating that my analysis was quite limited and *did not consider whether a lower cost resource should have been undertaken at an earlier time*. *See, e.g.*, Re PacifiCorp, Docket No. 01-035-37, Transcript at 118, l. 7-11 (Jan. 24, 2002).

In this case, it is now very important to ask whether the Company was forced into a hasty decision to consummate the West Valley Lease owing to a lack of planning in the months and years before. This high cost of West Valley vis-à-vis larger (albeit longer lead-time) resources raises a red flag concerning prudence.

In addition, there are a number of other issues concerning West Valley that differentiate it from the Gadsby project. First, West Valley apparently costs more than Gadsby. PacifiCorp obtained a price concession for the Gadsby CTs that it apparently did not receive for West Valley based on the figures shown in Exhibit ICNU/102.

Second, West Valley is a "greenfield" project, while Gadsby was able to take advantage of existing infrastructure at an existing plant. This would undoubtably work to lower the cost of Gadsby vis-à-vis West Valley.

Third, the Company was in a position to benefit from the quick start feature of the Gadsby CTs. However, having obtained 120 MW of quick start capacity, it is highly doubtful the Company would need any more. The Company already had a contract with a large industrial customer to provide approximately 70 MW of quick start capacity. With an additional 120 MW from Gadsby, it is hard to see how PacifiCorp could benefit from 200 MW more of quick start capacity from West Valley.

Finally, Gadsby offset power purchases and transmission expenses at SP-15. According to PacifiCorp's testimony and exhibits in the current Wyoming rate case (Docket No. 20000-ER-02-184), West Valley will offset purchases at the lower priced Palo Verde and Four Corners hubs. *See* Exhibit ICNU/103. For all these reasons, West Valley and Gadsby have much different economic impacts even though they are identical technologies. I will further discuss the market value of West Valley power in more detail in the next section of my testimony.

Q. ARE THERE OTHER PROBLEMS WITH THE WEST VALLEY PROJECT THAT HAVE A BEARING ON THE PRUDENCE QUESTION?

A. Yes. My <u>third</u> prudence "red flag" is the operational inflexibility of the West Valley Project. In the current Wyoming rate case, PacifiCorp's GRID studies modeling the Project assume that, whenever the capacity from one of the units is needed, it must run at a minimum of 30 MW. Running the units below this level is extremely inefficient and creates emissions problems at the site.

The net result of this inflexibility is that if only a small portion of a unit is needed (say for spinning reserve purposes) the plant must operate at nearly full load. As a result, the Company must back down lower cost units, or reduce lower cost purchases. Based on the GRID studies from the current Wyoming case, the inclusion of the West Valley Project in the PacifiCorp system for an entire year *increases* net power costs by $15 million compared to the case where West Valley does not run at all. This is a shocking result, because normally when a new resource is added to the system, it *reduces* the need to run higher cost plants and displaces higher cost native generation or purchases. On its face, this analysis says that the West Valley Project's energy costs must exceed market value. This conclusion is also corroborated by the Company's own analysis of the actual costs of West Valley, which I will discuss shortly. Exhibit ICNU/104 shows the results of this GRID study. While I have been unable to verify this result based on the GRID studies used earlier in this case, I have no reason to suspect the results would be any different.

Q. IS THERE ANY WAY THE COMPANY COULD HAVE BEEN AWARE OF THIS PROBLEM PRIOR TO SIGNING THE WEST VALLEY LEASE?

A. Certainly. It could and should have performed modeling studies to explore this issue. Tools like GRID are intended to allow planners to examine the costs and benefits of projects, taking such operational issues into account. The fact that the Company has leased the West Valley Project in the face of these operational problems is yet one more reason to doubt the prudence of the Lease agreement.

Q. PLEASE SUMMARIZE YOUR DISCUSSION OF THE PRUDENCE AND NECESSITY ISSUES RELATED TO WEST VALLEY.

A. The West Valley Lease costs are unnecessarily high. There are a number of "red flags" concerning the question of whether the West Valley Lease was a necessary or prudent transaction. These red flags provide ample reason to believe West Valley was not the least cost option. In fact, based on PacifiCorp's own GRID model, West Valley's operation actually *increases* net power costs on the system.

IV. MARKET VALUE OF WEST VALLEY POWER

Q. EXPLAIN WHY PERMITTING RECOVERY OF THE FULL COST OF THE LEASE VIOLATES OAR § 860-038-0080(1)(b).

A. As noted above, OAR § 860-038-0080(1)(b) prohibits "return on rate base" treatment for any new generating plants. However, the West Valley Lease is really "return on rate base" treatment in disguise.

Q. PLEASE EXPLAIN.

A. The conventional regulatory model for treating the cost of a new resource includes a return on investment plus depreciation as well as recovery of taxes, fees and operating costs. The West Valley Lease requires PacifiCorp to pay all of these costs, either directly or indirectly. In particular, return on investment and depreciation expenses are recovered in the Lease payment. It is quite obvious that, by structuring this transaction as a lease, the effect (or at least the attempt) is to convert costs that are not recoverable under OAR § 860-038-0080(1)(b) into recoverable ones. Inclusion of the Lease payment in rates would amount to allowing PacifiCorp to make an "end run" around the requirements of the rule. This would be a case of elevating form over substance.

Allowing rate base-like treatment would be particularly egregious in this case, because this proceeding was only intended to deal with PacifiCorp's variable net power costs, not return on investment or other fixed costs. PacifiCorp's original power cost filing in this docket originated from a stipulation in the Company's last general rate case, Docket No. UE-116. Re PacifiCorp, Docket No. UE-116, Order No. 02-212, Appendix C at 2 (Mar. 19, 2002). In that stipulation, ICNU, Commission Staff, CUB, and PacifiCorp agreed that this proceeding would deal only with variable net power costs, not return on investment or other fixed costs. In addition, the use of the GRID model already afforded the Company the opportunity to reflect the market value of West Valley in net power costs.

Q. HOW WOULD GRID ALLOW THE COMPANY TO INCLUDE THE MARKET VALUE OF WEST VALLEY POWER IN NET POWER COSTS?

A. The Company could have run GRID without West Valley. GRID would then purchase energy at normalized market prices instead of dispatching West Valley. In the UE-134 Net Power Cost study, however, the Company included West Valley at its forecasted dispatch cost.[1/] Hence, PacifiCorp had a mechanism to value West Valley at market, but instead chose a Lease, which allows recovery at cost.

Q. PACIFICORP CONDUCTED A RATHER COMPLEX RFP AND BIDDING PROCESS IN LATE 2001. DOES USE OF THIS PROCESS SATISFY THE MARKET VALUE REQUIREMENTS OF OAR § 860-038-0080(1)(b)?

A. No. OAR § 860-038-0080(1)(b) provides: "*Electric companies must include new generating resources in revenue requirement at market prices, and not at cost* . . . ." The

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1/ As discussed above, however, I believe that if the Company had run GRID without West Valley, the results would have indicated that the West Valley project increases system costs, even when priced at its dispatch cost (fuel) due to the operational problem the project engenders.

reference to market prices in the rule implies current market prices, because it would be meaningless to say that suppliers could price the output of new resources at the market prices in effect at some time in the past. Nevertheless, the Commission could interpret this rule to require valuation based on market prices at the time PacifiCorp entered into the Lease in March 2002. Under either interpretation, the bidding and RFP process does not demonstrate that the Project costs are consistent with *current* market prices or with market prices in March 2002.

Q. PLEASE EXPLAIN FURTHER WHY OAR § 860-038-0080(1)(b) SHOULD BE INTERPRETED TO REFER TO CURRENT MARKET PRICES.

A. It is not reasonable to assume that the above-referenced language would apply to the market prices in effect at the time a new resource was examined, or even committed to in the past. That would be an impossible and chaotic standard for regulators to deal with. First, it would imply different prices for every new asset built (even if they came on line at the same time). Second, it often takes months or years to build a new resource, and utilities have the option to delay or cancel those projects along the way. In the case of a long lead-time asset, the ranges of possibly allowable market prices would be enormous. For these reasons, it only makes sense to consider the requirements of OAR § 860-038-0080(1)(b) in the context of *current* market prices. Based on all available evidence, the cost of West Valley now exceeds current market prices. If the Commission does not agree with this interpretation, it should, at the very least, base its decision on market prices at the time PacifiCorp executed the West Valley Lease in March 2002. PacifiCorp has not demonstrated that the cost of the West Valley Lease was equal to market prices in March 2002.

Q. IN THE AFFILIATED INTEREST PROCEEDING RELATED TO THE WEST VALLEY LEASE, PACIFICORP RELIED ON A PRESUMPTION IN OAR § 860-027-0040(2)(k) TO CLAIM THAT THE COST OF THE LEASE WAS EQUIVALENT TO MARKET VALUE FOR THE PURPOSES OF THE COMMISSION'S TRANSFER PRICING POLICY. IS IT APPROPRIATE TO RELY ON THIS PRESUMPTION FOR THE PURPOSE OF DETERMINING MARKET VALUE UNDER OAR § 860-038-0080(1)(b)?

A. No. The Commission should not rely on this presumption. OAR § 860-027-0040 states:

> (1) Except as provided in sections (3) and (4) of this rule, the requirements of this rule will apply to any energy or large telecommunications utility seeking authority under ORS 757.490, ORS 757.495, ORS 759.385, and ORS 759.390. An application for financing to an affiliated interest shall be made under OAR 860-027-0030.
>
> . . .
>
> (2)(k) Transfer prices in contracts or agreements for the procurement of goods or services under competitive procurement shall be presumed to be the market value, subject to evaluation of the procurement process [.]

This presumption should not apply for several reasons. First, section (1) of the rule itself states that it applies in applications for approval of certain contracts and affiliated interest transactions under ORS §§ 757.490 and 757.495. OAR § 860-027-0040(1). This is not an affiliated interest proceeding. In this proceeding, the Commission is evaluating the West Valley Lease to determine whether permitting full recovery of the cost of the Lease will violate OAR § 860-038-0080(1)(b). There is no indication that it is appropriate to apply the presumption in OAR § 860-027-0040(2)(k) to satisfy the market value requirements in OAR § 860-038-0080(1)(b). Second, even if it were appropriate to consider this presumption, it is questionable whether the RFP was a valid "competitive procurement" process as required by OAR § 860-027-0040(2)(k). PacifiCorp leased West Valley from its affiliate, PPM, at a time when PPM had suspended construction of the Project and apparently had little other opportunity to sell the Project. In addition, in the final stages of the RFP process, after many other bids had been eliminated, PacifiCorp allowed PPM to restructure its original tolling proposal into the Lease. Under these circumstances, there is little assurance that the cost of the Lease actually reflects market value for a lease of a facility such as West Valley. Finally, as described below, the RFP process took place during a period of declining market prices. Thus, bids submitted in response to the RFP in September 2001 were outdated by the time PacifiCorp executed the Lease in March 2002. PacifiCorp could have sought new bids from other suppliers at this point, but, instead, chose to lease the expensive West Valley CTs from its affiliate.

Q. WHY DO THE WEST VALLEY PROJECT COSTS (INCLUDING THE LEASE PAYMENT) NOW EXCEED CURRENT MARKET LEVELS?

A. For the requirements of OAR § 860-038-0080(1)(b), "why" the West Valley Project costs exceed current market prices does not really matter. Nevertheless, the Company's timing of this transaction was not advantageous. Market prices in the West collapsed after the Federal Energy Regulatory Commission's ("FERC") imposition of price caps on June 19, 2001. San Diego Gas & Elec. Co. v. Sellers of Energy, Ancillary Serv. Into Mkts. Operated by the Cal. Indep. Sys. Operator, 95 FERC ¶ 61,418 (June 19, 2001). The ultimate decline in prices, however, was not immediate or automatic. Prices continued to fall long after June 19, 2001. In addition, there were still some fears of price volatility that persisted for some time. Further, the Western markets experience with price caps at the time PacifiCorp issued the RFP was not sufficient to know with certainty how the new price caps would work in practice. Because the new price caps allowed prices in excess of $90/MWh, there was still some fear that prices could remain high.

Exhibit ICNU/105 presents graphs showing California-Oregon Border ("COB") and Mid-Columbia ("Mid-C") daily market prices and ninety-day and sixty-day rolling averages for the period March 2001 to July 2002. The ninety-day and sixty-day rolling averages are provided because power suppliers would likely want to view the trend in prices before making long-term commitments.[2/] As the figures show, when the RFP was issued in September 2001, and even when the bids were refreshed in November 2001, prices were still trending downwards. This process of declining prices continued for some time. By March 2002, when the West Valley Lease was signed, the ninety-day and sixty-day rolling average prices had dropped substantially from the levels experienced in early September or early November.

Consequently, it is likely that potential bidders were still "spooked" at the time of the RFP process. By the time the Lease was signed, however, power prices had remained lower and much more stable for many months. It is likely that more attractive options may have been available at that time. Furthermore, prices continued to decline after the Lease was signed, but while construction of the Project was ongoing. By the time the Project was completed in June 2002, prices had fallen far below the costs of the Project including the Lease payment. PacifiCorp failed to reconsider the Project in light of the decline in prices at the time it signed the Lease in March 2002. In the face of declining market prices, it was imprudent for PacifiCorp to lease 200 MWs from an affiliate in March 2002 without seeking new bids from other suppliers.

[2/] Nothing in the selection of ninety and sixty-day rolling averages is intended to suggest these types of statistics are the only ones that traders might consider. These figures are simply presented to show the trend in market prices with some of the "noise" averaged out.

Q. IS THERE ANY ADDITIONAL EVIDENCE THAT DEMONSTRATES WEST VALLEY'S COST EXCEEDS MARKET VALUE?

A. Yes. As discussed above, the Company analyzed the costs and benefits of West Valley in the current Wyoming proceeding. The rebuttal testimony of PacifiCorp witness Stan Watters contains an exhibit that presents an analysis of the West Valley Project for a six-month period (June 2002 to November 2002). Exhibit ICNU/103 at 2-3. Although the Company alleged that the Project produced $7.2 million in benefits during this period, this conclusion is suspect because the alleged benefit is less than six months of Lease payments for the Project ($7.355 million). In addition, this estimate did not include the associated property taxes and fixed O&M expenses that the Company is obligated to pay during this time frame.

The six-month study performed by the Company also does not accurately reflect the *annual* cost impact of the Project. Power prices are typically higher during the June to November period than the rest of the year. PacifiCorp's load typically peaks in the summer, and the Project was justified on the basis of meeting summer peak demands. Thus, it is unlikely that results for an entire year would show nearly as favorable of a comparison. Indeed, there may be no benefit from operating the plant for the remaining six months of the year.

Second, Mr. Watters' analysis also ascribes $2.3 million in spinning reserve benefits from West Valley. It was alleged that this benefit is derived based on avoiding the need to commit capacity from the Company's Cholla plant to spinning reserve. This benefit is highly suspect because GRID studies that include West Valley for the entire year do not demonstrate any appreciable increase in Cholla generation with or without the West Valley units. Thus, it appears unlikely that West Valley is producing substantial spinning reserve benefits. Removing these benefits, and projecting the costs out for the entire year, indicates that the deficit (relative to market prices) for the Project could approach $10 million per year.

Finally, this analysis does not consider the additional costs stemming from the operational inflexibility of the facility. Mr. Watters has assumed that West Valley would be completely replaced by energy purchased at market prices. As shown above, the operational inflexibility of the plant results in situations where some of the generation from the facility is actually offsetting energy that costs far less than the market purchases assumed by Mr. Watters.

Q. DOES PACIFICORP ALREADY RECOVER ANY OF THE COSTS OF THE WEST VALLEY LEASE IN RATES?

A. Yes. Based on Staff's testimony in support of the stipulation in UE-134, PacifiCorp already recovers at least $11.5 million in rates related to West Valley. Re PacifiCorp, Docket No. UE-134, Staff/100, Wordley/3 (Apr. 8, 2002). In UE-134, Commission Staff proposed increasing net power costs by $11.5 million to reflect removal of the West Valley CTs. Id. Staff opposed inclusion of the costs of the West Valley Lease in rates based on a "desire to not prejudge PacifiCorp's Affiliated Interest Application in UI 196." Id. As a result, Staff removed the West Valley Lease, and imputed additional net power costs. This reconsideration proceeding addresses an additional $1.2 million in costs that PacifiCorp seeks to recover due to the excessive cost of the West Valley Project.

In addition, it is also probable that removal of West Valley from GRID would have actually *reduced* the net power costs used in UE-134 for the reasons discussed above, even aside from the additional $11.5 million added by the Staff. It does not appear that Staff developed its adjustments based on a GRID model run. This suggests strongly that the costs of West Valley have been recovered already and perhaps over-recovered. Indeed, I believe PacifiCorp should be required to produce a new GRID model run without West Valley. This information is vital to determine the actual level of West Valley costs already recovered in rates.

Q. WHAT IS THE CONCLUSION OF THIS SECTION OF YOUR TESTIMONY?

A. Inclusion of the full cost of the West Valley Lease in rates would exceed the market value of the West Valley power by a substantial margin. As a result, permitting PacifiCorp to recover the additional $1.2 million cost of the West Valley Lease in rates would violate OAR § 860-038-0080(1)(b). Given that the Lease payment was not "necessary" and does not demonstrate a prudent cost, the Commission should not allow recovery of the West Valley Lease payment at this time. If PacifiCorp is able to put forth a valid demonstration of the current market price of the West Valley power based on running GRID without West Valley, then it should make a proposal as to the appropriate market price to apply in this proceeding.

Q. PARAGRAPH NINE OF THE STIPULATION IN UE-134 CALLS FOR INCLUSION OF THE COSTS OF WEST VALLEY IN RATES IF THE COMMISSION APPROVED PACIFICORP'S AFFILIATED INTEREST APPLICATION IN UI-196. HOW SHOULD THE COMMISSION TREAT THAT PROVISION OF THE STIPULATION?

A. The Commission granted reconsideration to consider the appropriate ratemaking treatment of West Valley, as opposed to that provided in paragraph nine of the stipulation in UE-134. Re PacifiCorp, Docket Nos. UE-134 and UM-1047, Order No. 02-543 at 3-4 (Aug. 8, 2002). My testimony demonstrates that permitting the full recovery of the West Valley Lease costs would violate OAR § 860-038-0080(1)(b) and that the Lease is not otherwise necessary and prudent. As a result, the Commission should reject paragraph nine of the stipulation and disallow full recovery of the West Valley costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit ICNU/`102
PacifiCorp and Corrected Own vs. Lease Comparison for West Valley

Comparison A (West Valley vs. Gadsby Peakers) (Original PacifiCorp comparison)

		**	$/kW-mo
a	Investment in Gadsby Peakers (120 MW capacity):	$80,000	
b	Equivalent investment for 200MW capacity	$133,333	
c	Discount rate	7.56%	
d	15 year annuity Payment	$15,161	$6.32
e	West Valley Lease Payment	$14,710	$6.13
f	Annual Benefit	$451	$0.19

** Values in $1000

Analysis Considering Residual Value of CT (Corrected Comparison)

A	Escalation factor for 15 Years at 2.5% (1.+Esclation Rate)^15	144.83%	
B	Expected Life in years	25	
C	Remaining Life	10	
D	Percentage Residual Value bassed on remaining life (C/B)	40.00%	
E	Replacement Value Factor (D*A)	57.93%	
F	Residual Value based on Replacement Cost E*b	$77,243	
G	Discount Factor (1+Discount Rate)^15	33.51%	
H	NPV Credit For ownership (Residual Value) G*F	**$25,888**	
I	Payment Credit for Residual Value d/b*H	$2,944	
J	Adjusted Payment d-I	$12,218	$5.09

Gadsby Peaker and West Valley System/Wyoming Benefit Summary

Background:

PacifiCorp installed three 40 MW natural gas peaking generation units at Gadsby (Units 4-6) and leased five identical units at West Valley (Units 1-5). The West Valley units commenced commercial operation between June 2002 and July 2002. The Gadsby units were commercially operational early August 2002. The West Valley units have access to natural gas from both Questar and Kern River pipelines. The Gadsby units are supplied from Questar and do not have the fuel flexibility of the West Valley units.

Benefits:

These units provide System benefits for all of PacifiCorp's customers. Among other things, these generation units provide lower cost alternatives for: (1) energy and capacity that would otherwise have to be obtained from the market and (2) operating reserves that would otherwise have to be held on lower cost System thermal units. This analysis quantifies these particular benefits. Additional benefits are discussed in Mr. Watters' rebuttal testimony.

Analysis:

PacifiCorp has quantified both the System and Wyoming benefits of these units on an hourly basis from June 2002 through November 2002. The avoided energy cost is the difference between: (a) the daily Dow Jones price for on and off-peak power shaped hourly, and (b) the cost of generation plus variable O & M for each unit. The cost of generation is determined by multiplying the heat rate of each unit by the sum of (a) the daily index for Questar natural gas as reported in Platt's Gas daily, and (b) appropriate transportation charges. The reserve cost is the difference between: (a) the daily Dow Jones price for on and off-peak power shaped hourly, and (b) the cost of generation at the most expensive coal resource on PacifiCorp's System. The hourly generation for each unit was obtained and verified from emission data retrieved from each plant's CEM system.

Without these generation units PacifiCorp would either purchase power from Four-Corners/Palo Verde or SP-15 to serve its energy and capacity needs. Power purchases at Four-Corners/Palo Verde may not always possible, even though costs are lower than SP-15, due to transmission limitations. Therefore, to meet System load obligations on a dependable basis, PacifiCorp would have to purchase power at SP-15 and pay additional ISO and LADWP transmission charges.

This analysis assumed SP-15 savings associated with the Gadsby units and 4C/Palo Verde savings associated with the West Valley units. This approach is reasonable as

PacifiCorp originally assumed reduced transmission expenses out of SP-15 with the completion of the new Gadsby units. Through November 2002, the Gadsby and West Valley units saved PacifiCorp's customers $6.2 million for energy, $3.7 million for transmission, and $3 million for reserves for a total benefit of $12.9 million. Wyoming's share of this benefit, based on a 15% allocation factor, was $929K for energy, $550K for transmission, and $456K for reserves, for a total Wyoming benefit of $1.9 million. The supporting workpaper is attached. Unit availability statistics are also provided which indicate the units are being economically dispatched close to the original plan.

PPW System Benefit w/Gadsby & West Valley Peakers: SP15 View

Period Span — June '02- Nov '02	Gadsby	West Valley	Total
Total System Benefits	**$5,640,689**	**$12,909,409**	**$18,550,098**
Avoided SP 15 Energy Costs	$1,184,056	$3,606,427	$4,790,484
Avoided SP 15 Transmission Costs	$3,668,314	$7,051,354	$10,719,668
Avoided Cholla Reserve Costs	$788,319	$2,251,627	$3,039,946
Wyoming's Portion of System Benefits (15%)	**$846,103**	**$1,936,411**	**$2,782,515**
Avoided SP 15 Energy Costs	$177,608	$540,964	$718,573
Avoided SP 15 Transmission Costs	$550,247	$1,057,703	$1,607,950
Avoided Cholla Reserve Costs	$118,248	$337,744	$455,992

PPW System Benefit w/Gadsby & West Valley: 4C/Palo Verde View

Period Span — June '02- Nov '02	Gadsby	West Valley	Total
Total System Benefits	**$2,396,113**	**$7,263,245**	**$9,659,358**
Avoided 4C/PV Energy Costs	$1,607,794	$5,011,618	$6,619,412
Avoided Cholla Reserve Costs	$788,319	$2,251,627	$3,039,946
Wyoming's Portion of System Benefits (15%)	**$359,417**	**$1,089,487**	**$1,448,904**
Avoided 4C/PV Energy Costs	$241,169	$751,743	$992,912
Avoided Cholla Reserve Costs	$118,248	$337,744	$455,992

PPW System Benefit w/Gadsby & West Valley Peakers: SP15 View for Gadsby, 4C/Palo Verde View for West Valley

Period Span — June '02- Nov '02	Gadsby	West Valley	Total
Total System Benefits	**$5,640,689**	**$7,263,245**	**$12,903,934**
Avoided Energy Costs	$1,184,056	$5,011,618	$6,195,674
Avoided Transmission Costs	$3,668,314		$3,668,314
Avoided Cholla Reserve Costs	$788,319	$2,251,627	$3,039,946
Wyoming's Portion of System Benefits (15%)	**$846,103**	**$1,089,487**	**$1,935,590**
Avoided Energy Costs	$177,608	$751,743	$929,351
Avoided Transmission Costs	$550,247	$0	$550,247
Avoided Cholla Reserve Costs	$118,248	$337,744	$455,992

Actual Unit Availability Statistics (Since Start-Up)

Unit	Hours Dispatched (%)	Energy Produced (MWhs)	Average HL Rate (MW)
WV1	45%	67,678	28.6
WV2	56%	71,430	32.6
WV3	52%	76,630	32.7
WV4	51%	79,610	32.5
WV5	36%	45,209	24.4
Gad4	45%	58,211	31.3
Gad5	36%	45,647	23.5
Gad6	44%	45,177	26.3

PPW System Benefit w/Gadsby & West Valley Peakers: SP15 View

PPW System Benefit w/Gadsby & West Valley Peakers: SP15 View for Gadsby, 4C/Palo Verde View for West Valley

Period Span	June '02- Nov '02		
	Gadsby	West Valley	Total
Total System Benefits	**$5,640,689**	**$7,263,245**	**$12,903,934**
Avoided Energy Costs	$1,184,056	$5,011,618	$6,195,674
Avoided Transmission Costs	$3,668,314		$3,668,314
Avoided Cholla Reserve Costs	$788,319	$2,251,627	$3,039,946
Wyoming's Portion of System Benefits (15%)	**$846,103**	**$1,089,487**	**$1,935,590**
Avoided Energy Costs	$177,608	$751,743	$929,351
Avoided Transmission Costs	$550,247	$0	$550,247
Avoided Cholla Reserve Costs	$118,248	$337,744	$455,992

Actual Unit Availability Statistics (Since Start-Up)

Unit	Hours Dispatched (%)	Energy Produced (MWhs)	Average HL Rate (MW)
WV1	45%	67,678	28.6
WV2	56%	71,430	32.6
WV3	52%	76,630	32.7
WV4	51%	79,610	32.5
WV5	36%	45,209	24.4
Gad4	45%	58,211	31.3
Gad5	36%	45,647	23.5
Gad6	44%	45,177	26.3

Planned Unit Availability Statistics (Since Start-Up)

Unit	Hours Dispatched (%)	Energy Produced (MWhs)	Average HL Rate (MW)
WV1	59%	87,680	40
WV2	59%	87,680	40
WV3	59%	87,680	40
WV4	59%	87,680	40
WV5	59%	68,480	40
Gad4	33%	38,720	23
Gad5	33%	38,720	23
Gad6	33%	38,720	23

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PacifiCorp
Period Ending September 2002

GRID Results
Net Power Cost Analysis
($)

Exhibit ICNU 104 Pt. 1
Run With West Valley

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
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SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
AEPCO	785,051	-	-	-	-	-	-	-	-	-	376,320	408,731	-
Black Hills	11,819,968	1,195,222	1,165,234	1,197,803	1,089,602	959,028	234,934	1,022,672	1,052,735	844,149	898,965	1,089,891	1,069,736
Black Hills Capacity	1,080,000	180,000	180,000	180,000	180,000	180,000	180,000	-	-	-	-	-	-
BPA Flathead Sale	21,523,320	1,828,008	1,769,040	1,828,008	1,828,008	1,651,104	1,828,008	1,769,040	1,828,008	1,769,040	1,828,008	1,828,008	1,769,040
BPA Wind	2,267,141	225,722	254,827	257,737	236,812	194,765	201,023	180,371	138,883	144,286	145,470	133,763	153,483
CDWR	34,901,964	3,299,264	3,266,576	3,331,952	2,684,524	2,622,640	3,108,544	2,718,904	2,684,524	2,650,144	2,684,524	2,787,664	3,062,704
Clark Storage & Integration	4,706,081	647,320	999,907	761,255	159,852	227,329	294,963	237,627	330,979	205,127	186,168	319,320	336,236
Clark Wafertech	1,428,480	121,112	117,560	121,112	121,112	110,456	121,112	117,560	121,112	117,560	121,112	121,112	117,560
Citizens Power	3,390,938	297,891	419,755	246,437	463,557	436,289	-	292,570	307,968	410,625	451,687	64,160	-
COPD (BHP Steel)	862,772	125,936	122,180	125,936	125,936	114,668	125,936	122,180	-	-	-	-	-
Deseret Supplemental	7,056,868	576,203	497,815	582,801	486,464	445,622	762,743	555,543	520,553	545,360	690,041	754,265	639,458
Deseret Displacement	223,117	40,004	1,110	3,690	23	7,065	23,010	392	19,477	28,328	28,327	28,665	43,026
Flathead	6,377,280	541,632	524,160	541,632	541,632	489,216	541,632	524,160	541,632	524,160	541,632	541,632	524,160
Hurricane Sale	293,888	14,168	8,708	18,592	31,500	28,112	28,252	27,636	30,940	25,564	27,720	28,644	24,052
LADWP (IPP Layoff)	26,187,080	2,383,946	2,566,920	2,286,498	1,991,266	1,956,721	1,991,266	2,032,767	2,231,396	2,193,978	2,186,754	2,214,048	2,151,520
PSCO	54,875,495	4,716,380	4,481,726	4,702,296	4,520,489	4,305,779	4,702,172	4,447,816	4,520,487	4,525,446	4,692,259	4,702,168	4,558,478
Puget Sound	53,166,656	4,454,320	4,399,664	4,454,320	4,249,176	4,621,520	4,792,320	4,409,728	4,344,824	3,999,808	4,033,968	4,669,344	4,737,664
SCE	59,921,106	5,360,369	5,071,160	5,329,577	4,992,000	4,608,000	4,992,000	4,992,000	4,992,000	4,800,000	4,992,000	5,184,000	4,608,000
SDG&E Sale	3,632,160	1,223,880	1,184,400	1,223,880	-	-	-	-	-	-	-	-	-
Sierra Pac 2	24,733,908	2,236,397	2,080,710	2,284,713	1,974,788	1,920,779	2,165,408	1,998,615	1,936,664	1,849,296	1,998,615	2,165,408	2,122,518
SMUD	5,412,444	583,311	525,133	595,559	133,386	103,917	1,153,944	539,748	406,362	139,590	232,650	319,506	679,338
Springfield	9,458,754	840,856	897,997	920,536	719,166	665,415	719,166	593,308	610,916	593,308	610,916	1,464,052	823,117
Springfield II	(3,449,152)	(447,936)	(435,968)	(658,568)	(571,536)	(508,032)	(550,368)	(276,744)	-	-	-	-	-
UMPA	2,485,258	213,774	195,106	212,122	193,454	189,655	224,182	203,532	196,923	193,454	212,688	229,760	220,608
UMPA II	5,202,161	60,840	42,060	255,511	144,832	67,266	75,179	30,501	65,134	642,260	921,127	1,343,408	1,554,042
WAPA I	14,856,960	1,261,824	1,221,120	1,261,824	1,261,824	1,139,712	1,261,824	1,221,120	1,261,824	1,221,120	1,261,824	1,261,824	1,221,120
Total Long Term Firm Sales	353,199,698	31,980,442	31,556,899	32,065,222	27,557,865	26,537,025	28,977,247	27,761,045	28,143,342	27,422,602	29,122,776	31,659,371	30,415,860
Short Term Firm Sales													
COB	42,251,261	4,606,086	4,067,000	4,130,300	675,200	1,428,120	645,600	3,201,701	8,749,360	9,626,000	4,670,350	265,200	186,344
DSW	353,116,977	12,833,770	17,331,640	13,901,516	12,377,020	11,687,270	24,107,600	50,803,374	64,056,658	44,151,700	30,654,804	39,723,414	31,488,211
East Main	4,558,623	156,500	-	-	-	178,752	674,784	1,634,983	411,624	114,887	1,078,631	210,787	97,674
Mid C	232,094,577	22,948,101	25,476,440	28,214,568	12,875,164	11,171,240	23,895,168	40,360,964	32,856,060	17,054,800	9,115,816	4,025,910	4,100,346
West Main	2,349,678	220,212	731,542	212,056	220,212	195,744	212,056	557,856	-	-	-	-	-
Wyoming	1,968,075	3,596	5,604	5,286	4,283	4,011	4,056	331,638	3,971	7	967,207	7	638,407
Total Short Term Firm Sales	636,339,191	40,768,266	47,612,225	46,463,726	26,151,879	24,665,137	49,539,264	96,890,516	106,077,673	70,947,394	46,486,809	44,225,319	36,510,983
System Balancing Sales													
COB	24,677,539	1,207,601	3,057,933	4,417,696	2,674,003	2,268,079	3,277,339	1,734,837	742,684	85,300	1,349,822	2,075,176	1,787,069
DSW	38,810,745	2,470,283	2,678,954	5,999,878	4,678,827	2,518,973	685,347	3,012,765	1,997,179	4,672,765	5,171,205	2,778,483	2,146,087
Mid C	13,778,535	455,488	329,940	1,544,838	511,788	377,521	461,650	767,477	1,396,527	454,621	1,107,165	3,210,594	3,160,926
Trapped Energy	35,853	-	-	-	-	-	-	58	1,118	34,028	321	-	328
Total System Balancing Sales	77,302,673	4,133,372	6,066,827	11,962,412	7,864,618	5,164,573	4,424,336	5,515,137	4,137,508	5,246,714	7,628,514	8,064,253	7,094,409
TOTAL SPECIAL SALES	1,066,841,561	76,882,080	85,235,952	90,491,360	61,574,362	56,366,735	82,940,847	130,166,698	138,358,524	103,616,709	83,238,099	83,948,943	74,021,252

PURCHASED POWER & NET INTERCHANGE		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Long Term Firm Purchases													
Aquila hydro hedge	1,750,002	145,837	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833
APS Supplemental Purchase	233,571	233,571	-	-	-	-	-	-	-	-	-	-	-
Avista Summer Capacity	5,378,184	-	-	-	-	-	-	-	-	558,012	1,134,150	1,992,114	1,693,908
Black Hills CTs	1,375,594	69,582	136,676	97,725	120,699	127,125	96,587	122,400	122,400	122,400	120,000	120,000	120,000
BPA Entitlement Capacity	24,069	2,145	2,145	2,145	2,145	2,145	2,145	1,863	1,863	1,863	1,870	1,870	1,870
BPA FC IV Exchange	2,799	262	296	299	301	247	255	229	176	183	185	170	195
BPA Peaking	58,719,000	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250
BPA So. Idaho Exchange	(314,565)	-	-	-	-	-	-	(17,744)	(11,626)	(60,527)	(100,911)	(63,516)	(60,242)
BPA Supplemental Capacity	24,069	2,145	2,145	2,145	2,145	2,145	2,145	1,863	1,863	1,863	1,870	1,870	1,870
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark S&I Purchases	7,643,934	370,370	470,278	775,766	921,098	801,027	1,015,777	423,691	1,199,217	279,003	324,607	496,567	566,533
Colockum Capacity Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Constellation temperature hed	687,918	-	-	-	-	-	-	-	-	143,564	156,854	193,750	193,750
Deseret G&T Expansion	3,401,835	298,932	279,921	335,565	278,520	250,705	390,984	170,724	260,598	205,329	268,986	322,362	339,211
Deseret G&T Non Firm	1,406,930	253,833	8,060	4,330	3,163	11,121	103,517	243,526	41,948	61,179	286,017	183,680	206,556
Deseret Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas PUD Settlement	1,012,916	41,310	55,653	51,507	92,253	78,464	41,553	130,369	178,701	205,596	31,331	49,527	56,652
Element Re temperature hedg	242,920	-	-	-	-	-	-	-	-	(387,200)	80,120	275,000	275,000
Enron Purchase	863,200	448,200	415,000	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreemer	-	-	-	-	-	-	-	-	-	-	-	-	-
Fort James	17,421,891	1,436,476	1,390,138	1,436,476	1,494,223	1,349,620	1,494,223	1,446,022	1,494,223	1,446,022	1,494,223	1,494,223	1,446,022
Gemstate	2,273,521	207,400	19,221	205,100	205,700	201,800	206,700	201,800	201,800	201,800	207,400	207,400	207,400
Grant County	3,068,380	206,780	165,620	213,150	223,930	174,930	203,840	259,700	327,320	349,860	360,150	334,670	248,430
Hermiston Purchase	68,836,933	6,423,886	6,562,715	6,376,772	5,954,349	5,651,548	6,417,108	5,650,618	5,824,516	3,559,690	3,542,298	6,481,029	6,392,406
Idaho Power RTSA return	-	-	-	-	-	-	-	-	-	-	-	-	-
IPP Purchase	26,187,080	2,383,946	2,566,920	2,286,498	1,991,266	1,956,721	1,991,266	2,032,767	2,231,396	2,193,978	2,186,754	2,214,048	2,151,520
MagCorp	1,324,896	-	-	-	-	-	-	-	-	289,044	404,694	399,261	231,898
Mid Columbia	16,077,307	1,271,410	1,254,440	1,497,657	1,257,593	1,239,924	1,266,453	922,516	1,289,779	2,403,006	1,214,012	1,225,873	1,234,644
Morgan Stanley call	2,916,000	-	-	-	-	-	-	-	-	773,000	773,000	685,000	685,000
NuCor	1,207,500	94,500	94,500	94,500	94,500	94,500	105,000	105,000	105,000	105,000	105,000	105,000	105,000
P4 Production	1,287,500	115,000	115,000	115,000	115,000	115,000	-	-	-	-	-	475,000	237,500
PGE Cove	193,503	18,500	18,500	18,500	18,500	18,500	2,481	23,522	15,000	15,000	15,000	15,000	15,000
PSCO FC III Storage Agreeme	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Biomass	16,669,448	1,604,231	1,606,575	1,605,160	1,561,509	1,157,870	1,157,870	1,157,870	1,157,870	1,157,870	1,387,886	1,560,092	1,554,645
QF D.R. Johnson	6,298,439	545,661	228,878	116,831	593,223	548,367	596,400	411,659	658,165	629,700	666,215	648,829	654,511
QF Hydro East	3,244,992	251,712	196,239	328,193	264,489	216,734	190,756	315,130	321,287	482,887	263,193	202,387	211,985
QF Hydro West	17,406,450	900,994	1,046,772	1,396,139	2,079,242	1,249,752	1,679,894	2,071,491	1,994,771	1,733,588	1,132,684	1,093,291	1,027,832
QF Other	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Sunnyside	29,767,162	4,288,962	5,149,137	5,292,500	1,711,736	1,628,561	1,323,585	1,684,011	1,711,736	1,684,011	1,774,222	1,774,222	1,744,481
QF Warm Springs (Pelton)	1,858,130	491,028	671,628	695,474	-	-	-	-	-	-	-	-	-
Rock River	5,860,602	-	559,421	707,219	711,623	585,209	603,973	542,001	417,315	433,599	437,077	401,921	461,244
SCE Firm Capacity	4,415,357	950,140	1,732,608	1,732,608	-	-	-	-	-	-	-	-	-
Sempra call	3,415,300	-	-	-	-	-	-	-	-	712,680	1,061,080	1,066,540	575,000
SF Phosphates	5,755,347	620,160	1,094,400	1,130,880	330,429	298,452	330,429	319,770	330,429	319,770	330,429	330,429	319,770
Small Purchases east	421,304	28,618	32,788	42,101	55,843	39,043	38,190	38,035	35,321	33,301	33,712	22,361	21,991
Small Purchases west	322,838	1,137	10,415	2,807	3,590	4,338	3,859	3,129	1,043	1,460	215,320	75,319	421
TransAlta Purchase	81,459,264	6,326,309	6,127,778	6,336,133	5,658,434	5,108,576	5,658,432	3,808,204	3,937,794	3,811,258	11,689,104	11,680,038	11,317,206
Tri-State Purchase	11,117,698	982,919	922,285	994,587	844,761	872,091	1,163,420	890,324	886,098	767,360	774,122	942,085	1,077,647
DSM (Load Curtailment)	9,644,182	1,420,362	782,597	39,037	46,282	-	1,159,890	1,015,740	1,049,598	1,015,740	1,049,598	1,049,598	1,015,740
Total Long Term Firm Purchases	420,936,904	37,331,200	38,761,032	38,973,423	31,680,363	28,826,606	32,288,407	29,017,232	30,827,212	30,292,916	38,464,150	43,099,355	41,375,007

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		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Short Term Firm Purchases													
COB	50,733,164	10,814,869	10,286,000	11,164,850	-	-	703,513	4,073,353	6,701,930	4,668,300	2,320,350	-	-
DSW	357,770,749	4,555,389	6,263,150	7,522,430	5,033,600	4,926,020	13,489,240	45,803,231	60,331,548	43,935,366	56,918,074	62,606,094	46,386,607
East Main	11,874,494	-	252,000	-	-	213,600	-	987,929	580,450	2,361,338	3,677,649	2,243,978	1,557,550
Mid C	255,968,387	12,123,383	16,605,420	23,308,512	15,544,254	9,648,060	19,722,868	40,870,656	39,073,408	31,823,960	18,956,440	16,135,360	12,156,066
West Main	7,983,895	250,796	213,200	435,800	507,600	855,358	936,260	921,225	447,460	716,800	2,509,170	120,507	69,720
Wyoming	81,600	-	-	-	-	-	63,000	-	18,600	-	-	-	-
Total Short Term Firm Purchases	684,412,290	27,744,436	33,619,770	42,431,592	21,085,454	15,643,038	34,914,881	92,656,394	107,153,396	83,505,764	84,381,683	81,105,939	60,169,943
System Balancing Purchases													
COB	9,986,082	835,524	425,276	645,330	948,685	346,209	1,253,355	145,138	1,294,446	2,653,251	377,407	750,895	310,567
DSW	13,912,151	651,906	773,443	87,480	140,769	382,053	5,113,406	384,442	1,157,648	999,530	688,343	2,699,289	833,843
Mid C	41,474,844	5,759,595	6,564,427	5,254,981	3,907,032	3,735,166	4,872,195	4,767,024	3,068,525	567,304	586,827	1,331,315	1,060,453
Emergency Purchases	68,345	-	-	-	-	-	-	-	-	-	15,738	52,606	-
Total System Balancing Purchas	65,441,422	7,247,026	7,763,147	5,987,791	4,996,487	4,463,427	11,238,956	5,296,603	5,520,619	4,220,084	1,668,315	4,834,106	2,204,863
TOTAL PURCHASED PW & NET I	1,170,790,615	72,322,661	80,143,949	87,392,806	57,762,304	48,933,070	78,442,244	126,970,229	143,501,227	118,018,765	124,514,148	129,039,400	103,749,813
WHEELING & U. OF F. EXPENSE													
Firm Wheeling	89,883,670	8,020,818	8,529,696	9,160,576	9,127,962	8,240,627	7,483,911	6,437,098	5,557,935	8,395,605	6,347,367	6,334,708	6,247,367
Non-Firm Wheeling	1,298,093	78,154	135,411	121,707	96,256	87,034	140,454	76,050	62,254	156,187	139,039	130,742	74,806
TOTAL WHEELING & U. OF F. EX	91,181,763	8,098,972	8,665,107	9,282,283	9,224,218	8,327,661	7,624,365	6,513,148	5,620,189	8,551,792	6,486,406	6,465,450	6,322,173
THERMAL FUEL BURN EXPENSE													
Blundell	3,764,784	329,477	318,370	322,755	330,317	295,315	323,315	317,810	330,037	311,928	329,477	326,676	229,307
Carbon	10,940,282	577,104	949,047	960,152	953,563	800,189	933,545	952,271	979,534	926,251	979,042	982,784	946,801
Cholla	31,976,097	2,723,230	2,810,042	2,679,046	2,565,923	2,467,825	1,968,381	2,620,105	2,877,207	2,538,367	2,739,673	3,020,029	2,966,271
Colstrip	7,207,464	448,058	390,818	650,884	652,368	588,639	650,993	629,975	646,987	628,950	640,380	651,648	627,764
Craig	11,285,248	996,478	933,212	965,689	972,188	854,628	965,443	710,663	1,058,135	853,361	956,822	1,040,993	977,637
Dave Johnston	43,698,619	3,847,053	3,722,348	3,837,052	3,847,853	3,469,779	3,836,066	3,719,490	3,713,799	2,540,854	3,619,667	3,842,023	3,702,635
Gadsby	12,100,904	917,862	460,506	349,204	201,738	-	331,927	1,048,358	1,069,550	1,527,041	2,218,650	2,596,894	1,379,173
Gadsby CTs	1,853,624	-	-	-	-	-	-	-	-	-	-	-	1,853,624
Hayden	5,250,472	473,243	418,275	435,652	441,686	355,479	229,182	444,541	502,368	437,360	499,591	530,578	482,517
Hermiston	36,806,508	3,623,149	3,844,209	3,877,195	3,788,841	3,268,568	3,680,603	2,863,567	3,044,761	803,445	786,437	3,672,511	3,553,221
Hunter	67,706,248	5,902,048	5,845,924	6,014,291	6,029,619	5,409,886	5,969,394	3,877,139	5,494,336	5,803,119	6,016,294	6,010,625	5,333,573
Huntington	57,845,594	4,107,250	4,941,432	5,076,454	5,084,999	4,519,803	5,078,740	4,946,540	4,119,710	4,855,256	5,091,208	5,104,663	4,919,538
Jim Bridger	99,407,760	8,916,613	8,641,576	8,720,408	9,026,488	8,106,064	8,783,323	8,307,130	6,657,850	6,879,726	7,838,679	8,962,598	8,567,306
Little Mountain	7,102,411	782,814	759,570	829,770	859,745	776,540	815,254	623,222	608,773	444,442	50,563	79,183	472,533
Naughton	53,581,640	4,655,298	4,277,353	4,438,323	4,512,235	4,100,397	3,644,765	4,735,325	4,892,868	4,193,766	4,640,103	4,892,712	4,598,495
West Valley CT	37,965,960	4,159,262	3,515,374	3,531,966	2,853,415	2,800,216	3,769,290	2,507,035	2,943,019	2,434,910	2,968,902	3,498,882	2,983,690
Wyodak	15,263,838	1,386,391	1,341,427	1,383,006	1,386,814	1,251,077	1,383,288	847,535	1,275,122	1,230,646	1,274,872	1,273,617	1,230,043
TOTAL FUEL BURN EXPENSE	503,757,451	43,845,329	43,169,482	44,071,848	43,507,793	39,064,405	42,363,511	39,150,705	40,214,055	36,409,423	40,650,358	46,486,416	44,824,127
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NET POWER COST	698,888,267	47,384,882	46,742,586	50,255,576	48,919,953	39,958,401	45,489,273	42,467,385	50,976,946	59,363,270	88,412,813	98,042,323	80,874,860
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Net Power Cost/Net System	***13.11***	***11.22***	***10.65***	***10.71***	***10.23***	***9.53***	***10.55***	***10.46***	***11.77***	***13.44***	***18.35***	***20.17***	***19.13***

PacifiCorp **GRID Results** **Base Case 2002-09-25**

Net Power Cost Energy Analysis

Period Ending September 2002 (MWH)

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
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NET SYSTEM LOAD	53,307,530	4,224,160	4,388,624	4,693,252	4,782,342	4,191,171	4,310,301	4,061,804	4,330,878	4,418,307	4,817,333	4,860,848	4,228,508
SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
AEPCO	15,615	-	-	-	-	-	-	-	-	-	6,840	8,775	-
Black Hills	414,469	40,833	38,048	41,072	36,422	33,601	38,114	35,179	37,970	19,452	19,575	38,112	36,092
BPA Flathead Sale	472,986	40,176	38,880	40,176	40,176	36,288	40,176	38,880	40,176	38,880	40,176	40,176	38,826
BPA Wind	46,475	4,349	4,910	4,966	4,996	4,109	4,241	3,805	2,930	3,044	3,069	2,822	3,234
CDWR	614,900	58,600	57,400	59,800	44,700	42,000	63,200	46,200	44,700	43,200	44,700	49,200	61,200
Clark Storage & Integration	176,888	17,790	30,111	23,589	5,623	8,428	12,427	14,020	19,797	12,956	9,575	10,380	12,192
Clark Wafertech	87,590	7,440	7,200	7,440	7,440	6,720	7,440	7,200	7,440	7,200	7,440	7,440	7,190
Citizens Power	105,910	9,350	13,175	7,735	14,450	13,600	-	9,120	9,600	12,800	14,080	2,000	-
COPD (BHP Steel)	50,880	7,440	7,200	7,440	7,440	6,720	7,440	7,200	-	-	-	-	-
Deseret Supplemental	328,463	27,900	27,000	27,900	27,900	25,200	27,900	27,000	27,900	27,000	27,900	27,900	26,963
Deseret Displacement	29,749	5,334	148	492	3	942	3,068	52	2,597	3,777	3,777	3,822	5,737
Flathead	140,144	11,904	11,520	11,904	11,904	10,752	11,904	11,520	11,904	11,520	11,904	11,904	11,504
Hurricane Sale	10,495	506	311	664	1,125	1,004	1,009	987	1,105	913	990	1,023	858
LADWP (IPP Layoff)	539,002	46,290	49,843	44,398	42,855	38,707	42,855	42,583	48,023	45,960	46,312	46,890	44,286
PSCO	1,156,355	102,080	91,520	101,446	94,336	85,184	102,080	91,238	94,336	94,547	101,658	102,080	95,850
Puget Sound	1,053,200	104,000	100,800	104,000	72,200	94,000	104,000	81,600	77,800	57,600	59,600	96,800	100,800
SCE	962,600	77,700	72,000	76,900	83,200	76,800	83,200	83,200	83,200	80,000	83,200	86,400	76,800
SDG&E Sale	220,800	74,400	72,000	74,400	-	-	-	-	-	-	-	-	-
Sierra Pac 2	460,575	42,525	36,000	44,550	35,625	33,075	44,625	36,750	33,825	29,700	36,750	44,625	42,525
SMUD	350,400	38,100	34,300	38,900	8,600	6,700	74,400	34,800	26,200	9,000	15,000	20,600	43,800
Springfield	210,269	19,040	18,432	19,040	14,875	13,425	14,875	14,400	14,875	14,400	14,875	33,600	18,432
UMPA	41,760	3,960	3,056	3,880	2,976	2,792	4,464	3,464	3,144	2,976	3,304	4,080	3,664
UMPA II	132,119	2,160	1,440	9,407	4,768	2,723	3,570	1,347	2,716	23,596	18,308	29,524	32,560
WAPA I	464,227	39,432	38,160	39,432	39,432	35,616	39,432	38,160	39,432	38,160	39,432	39,432	38,107
Total Long Term Firm Sales	8,085,871	781,309	753,455	789,532	601,045	578,386	730,421	628,706	629,671	576,680	608,465	707,584	700,619
Short Term Firm Sales													
COB	1,413,025	109,875	94,400	94,400	33,600	79,200	37,200	107,175	328,000	322,000	183,200	15,600	8,375
DSW	11,533,475	428,025	629,000	462,000	472,400	523,400	964,000	1,679,125	2,182,120	1,364,200	823,680	1,033,800	971,725
East Main	300,129	7,825	-	-	-	8,400	31,340	64,040	15,540	13,075	68,392	48,408	43,109
Mid C	7,259,616	276,725	385,600	464,096	486,440	483,200	895,200	1,521,660	1,439,760	702,400	349,560	141,000	113,975
West Main	117,424	10,800	44,624	10,400	10,800	9,600	10,400	20,800	-	-	-	-	-
Wyoming	66,024	27	43	43	37	36	38	12,436	37	720	31,944	744	19,919
Short Term Firm Sales	20,689,693	833,277	1,153,667	1,030,939	1,003,277	1,103,836	1,938,178	3,405,236	3,965,457	2,402,395	1,456,776	1,239,552	1,157,103
System Balancing Sales													
COB	1,048,655	51,365	126,120	175,374	134,174	105,881	96,372	75,775	42,169	5,463	67,770	96,636	71,557
DSW	1,447,939	95,564	100,261	214,129	203,330	110,170	21,810	103,795	74,149	160,517	174,373	114,458	75,384
Mid C	770,341	22,232	16,466	70,827	26,991	19,504	14,933	45,692	79,161	87,029	102,254	151,916	133,336
Trapped Energy	79,252	-	-	-	-	-	-	33	716	77,918	377	-	207
Total System Balancing Sales	3,346,187	169,160	242,847	460,331	364,495	235,555	133,114	225,295	196,195	330,927	344,773	363,010	280,484
TOTAL SPECIAL SALES	32,121,752	1,783,746	2,149,969	2,280,801	1,968,818	1,917,777	2,801,713	4,259,237	4,791,323	3,310,002	2,410,015	2,310,146	2,138,206
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TOTAL REQUIREMENTS	85,429,281	6,007,906	6,538,593	6,974,053	6,751,160	6,108,948	7,112,014	8,321,042	9,122,201	7,728,309	7,227,347	7,170,994	6,366,714

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PURCHASED POWER & NET INTERCHANGE		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Long Term Firm Purchases													
APS Exchange	-	78,240	138,240	142,560	142,560	69,120	-	-	(78,240)	(138,240)	(142,560)	(142,560)	(69,120)
APS Supplemental Purchase	12,250	12,250	-	-	-	-	-	-	-	-	-	-	-
Avista Seasonal Exch	-	-	-	(18,600)	(4,300)	(4,700)	-	-	-	-	50	18,550	9,000
Avista Summer Capacity	82,800	-	-	-	-	-	-	-	-	5,400	11,250	32,550	33,600
BPA Exchange	93	(66,666)	(66,667)	-	-	-	(50,000)	-	-	133,898	116,102	-	(66,574)
BPA FC II Storage Agreement	320	183	111	42	38	(93)	47	(35)	(100)	37	24	(14)	80
BPA FC IV Storage Agreemen	2,993	1,712	1,030	392	362	(875)	443	(321)	(929)	343	229	(135)	743
BPA Peaking	15,263	19,333	(13,135)	17,113	(29,785)	-	22,015	(24,513)	27,935	(38,480)	6,568	12,950	15,263
BPA So. Idaho Exchange	51,772	1,461	2,413	2,796	2,653	1,347	419	2,587	1,891	7,734	12,700	8,123	7,647
BPA Supplemental Capacity	28	8	(80)	176	(376)	(8)	288	(192)	192	(192)	(184)	280	116
Canadian Entitlement	(74,399)	(6,399)	(6,168)	(6,207)	(6,399)	(5,706)	(6,207)	(6,168)	(6,399)	(5,976)	(6,399)	(6,399)	(5,971)
Clark S&I Purchases	362,444	14,580	16,598	28,912	45,030	40,154	39,665	24,190	77,162	15,542	18,313	19,002	23,296
Colockum Capacity Exchange	(199,332)	(13,797)	(18,018)	(15,498)	(19,404)	(17,955)	(378)	(18,585)	(19,278)	(20,160)	(19,656)	(18,774)	(17,829)
Cowlitz Swift	25,621	(20)	(58)	(5)	(5)	(47)	(47)	(6)	6,315	6,131	5,270	3,385	4,708
CSPE	79,364	6,354	6,138	7,470	7,470	6,732	6,336	6,000	6,208	6,016	7,312	7,312	6,016
Deseret G&T Expansion	216,485	18,201	18,668	20,068	19,134	16,801	17,267	11,667	19,134	18,668	19,134	18,201	19,543
Deseret G&T Non Firm	69,096	14,265	496	240	205	719	4,760	13,104	2,438	3,012	12,201	7,737	9,921
Douglas PUD Settlement	78,001	3,631	4,447	5,164	7,213	7,002	7,327	7,252	9,489	9,537	6,795	5,899	4,247
Enron Purchase	20,800	10,800	10,000	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreemei	1,544	145	163	165	165	137	141	126	98	101	101	94	108
Foote Creek I	121,711	11,389	12,858	13,004	13,085	10,761	11,106	9,966	7,673	7,973	8,037	7,390	8,469
Fort James	373,484	31,724	30,701	31,724	31,724	28,654	31,724	30,701	31,724	30,701	31,724	31,724	30,658
Gemstate	34,628	-	-	-	-	-	-	-	2,992	12,254	10,956	8,426	-
Grant County	87,668	5,908	4,732	6,090	6,398	4,998	5,824	7,420	9,352	9,996	10,290	9,562	7,098
Hermiston Purchase	1,381,256	155,171	156,732	152,136	139,533	115,545	146,537	106,476	116,329	1,020	153	149,110	142,512
Hurricane Purchase	1,047	51	100	48	148	94	81	60	79	92	88	102	104
Idaho Power RTSA Return	(78,329)	(6,840)	(7,200)	(7,160)	(7,416)	(6,624)	(6,584)	(4,896)	(4,944)	(6,560)	(8,336)	(5,976)	(5,793)
IPP Purchase	539,002	46,290	49,843	44,398	42,855	38,707	42,855	42,583	48,023	45,960	46,312	46,890	44,286
MagCorp	34,808	-	-	-	-	-	-	-	-	8,400	9,776	9,720	6,912
Mid Columbia	2,170,403	165,697	130,306	155,671	263,465	245,300	195,191	109,041	151,396	212,065	221,829	175,009	145,433
Morgan Stanley call	3,200	-	-	-	-	-	-	-	-	1,600	1,600	-	-
PGE Cove	14,603	2,038	1,973	1,611	1,014	942	1,014	990	1,014	990	1,014	1,014	989
PSCO FC III Storage Agreeme	294	3,114	3,401	1,262	206	(1,703)	(1,499)	(601)	(2,626)	(1,506)	299	(432)	379
QF Biomass	97,765	10,765	12,995	14,616	14,823	19	-	-	-	-	15,656	14,971	13,920
QF D.R. Johnson	62,930	4,185	5,400	5,580	5,022	5,040	5,580	5,400	5,580	4,590	5,580	5,580	5,393
QF Hydro East	61,227	4,736	3,717	6,131	5,281	3,777	3,609	5,903	5,990	9,199	5,010	3,852	4,022
QF Hydro West	187,554	9,010	10,955	15,497	21,980	13,434	17,944	22,555	22,496	18,772	12,298	11,762	10,851
QF Other	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Sunnyside	385,013	26,865	33,581	34,700	34,700	31,342	19,029	33,581	34,700	33,581	34,700	34,700	33,534
QF Warm Springs (Pelton)	19,797	6,203	6,386	7,208	-	-	-	-	-	-	-	-	-
Redding Exchange	17,262	(9,164)	(4,397)	10,755	8,610	7,852	750	(2,678)	(1,025)	6,108	5,253	3,058	(7,860)
Rock River	165,162	-	15,767	19,933	20,057	16,494	17,023	15,276	11,762	12,221	12,319	11,328	12,982
SCE Firm Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line Storage Agree	80,688	-	-	-	45,816	38,410	(7,508)	1,602	8,660	6,103	(3,381)	(969)	(8,045)
Sempra call	25,600	-	-	-	-	-	-	-	-	3,200	11,200	11,200	-
SF Phosphates	77,211	3,264	5,760	5,952	7,068	6,384	7,068	6,840	7,068	6,840	7,068	7,068	6,831
Small Purchases east	6,867	481	538	662	890	538	590	663	630	589	589	319	378
Small Purchases west	8,433	71	356	193	230	302	259	212	70	98	5,635	1,521	(514)
TransAlta Purchase	2,764,028	216,432	209,640	216,768	216,600	195,552	216,600	209,472	216,600	209,640	288,800	288,576	279,348
Tri-State Exchange	(850)	26,000	25,200	26,000	26,000	23,500	26,000	(25,200)	(26,000)	(25,200)	(26,000)	(26,000)	(25,150)
Tri-State Purchase	284,810	31,123	26,900	31,935	17,408	19,105	37,200	20,238	19,975	12,600	13,020	23,453	31,855
Total Long Term Firm Purchases	9,672,414	838,791	830,421	979,501	1,080,058	911,051	812,469	610,710	713,434	624,697	768,738	789,159	713,384
Short Term Firm Purchases													
COB	979,875	111,750	108,000	130,800	-	-	23,750	138,175	252,200	142,000	73,200	-	-
DSW	8,719,620	124,000	198,600	232,800	194,200	219,000	517,600	1,452,325	1,958,880	1,277,240	859,400	969,800	715,775
East Main	324,924	-	8,400	-	-	9,936	744	33,757	20,816	74,827	85,812	51,731	38,901
Mid C	9,634,623	224,200	400,800	595,800	507,400	390,000	768,400	1,601,418	1,834,680	1,412,000	889,400	582,400	428,125
West Main	497,614	11,545	16,160	13,376	13,776	27,408	30,116	29,454	19,716	57,280	264,216	10,056	4,512
Wyoming	3,840	-	-	-	-	-	2,640	-	1,200	-	-	-	-
Total Short Term Firm Purchases	20,160,496	471,495	731,960	972,776	715,376	646,344	1,343,250	3,255,128	4,087,492	2,963,347	2,172,028	1,613,987	1,187,313

System Balancing Purchases													
COB	556,213	33,806	21,310	30,293	55,630	17,384	39,888	6,214	53,999	226,065	23,295	35,084	13,245
DSW	586,554	28,303	46,596	3,940	9,740	21,233	159,734	26,478	73,216	101,299	26,702	60,454	28,859
Mid C	1,911,283	228,463	298,080	212,902	219,880	186,092	141,362	233,691	150,145	59,317	66,661	69,658	45,031
Emergency Purchases	583	-	-	-	-	-	-	-	-	-	145	438	-
Total System Balancing Purchas	3,054,633	290,572	365,987	247,135	285,250	224,710	340,983	266,383	277,360	386,681	116,803	165,634	87,135
TOTAL PURCHASED PW & NET I	32,887,543	1,600,858	1,928,368	2,199,412	2,080,684	1,782,105	2,496,702	4,132,221	5,078,286	3,974,725	3,057,570	2,568,780	1,987,832
THERMAL GENERATION													
Blundell	166,635	14,583	14,092	14,286	14,620	13,071	14,310	14,067	14,608	13,806	14,583	14,459	10,149
Carbon	1,331,631	70,459	115,511	116,862	116,031	97,341	113,666	115,896	119,222	112,681	119,151	119,602	115,209
Cholla	2,458,432	208,522	217,146	205,137	195,249	189,434	152,231	200,611	222,004	193,506	210,047	234,136	230,411
Colstrip	1,068,041	66,370	57,959	96,477	96,715	87,260	96,494	93,374	95,824	93,210	94,731	96,600	93,026
Craig	1,192,511	105,312	98,581	102,017	102,719	90,272	102,001	75,183	111,921	90,018	101,060	110,083	103,343
Dave Johnston	5,722,084	503,823	487,489	502,470	503,935	454,412	502,343	487,100	486,614	332,103	473,839	503,139	484,818
Gadsby	231,893	11,505	6,205	4,695	2,540	-	4,450	16,320	16,685	31,038	50,723	61,461	26,272
Gadsby CTs	53,952	-	-	-	-	-	-	-	-	-	-	-	53,952
Hayden	469,167	42,295	37,349	38,894	39,430	31,724	20,478	39,757	44,913	39,070	44,664	47,455	43,137
Hermiston	1,381,256	155,171	156,732	152,136	139,533	115,545	146,537	106,476	116,329	1,020	153	149,110	142,512
Hunter	8,316,934	725,591	718,492	738,881	740,931	664,350	733,417	474,645	674,429	712,697	739,144	738,391	655,967
Huntington	6,838,640	484,114	584,287	600,165	601,242	534,303	600,494	584,903	488,579	573,511	601,874	603,568	581,600
Jim Bridger	10,511,420	943,820	914,896	922,419	955,816	858,260	929,271	879,279	704,048	723,407	824,877	948,753	906,575
Little Mountain	104,648	9,969	10,337	11,393	11,393	10,291	10,681	10,337	9,969	8,660	1,021	1,650	8,946
Naughton	4,860,202	422,387	387,018	401,837	409,053	371,961	329,347	430,877	445,215	378,830	420,852	445,125	417,701
West Valley CT	870,577	76,200	67,950	68,101	53,100	52,110	70,145	59,270	69,426	69,668	90,445	110,359	83,804
Wyodak	2,181,615	198,748	192,300	198,233	198,813	179,340	198,276	121,480	181,505	175,127	181,466	181,270	175,057
TOTAL THERMAL GENERATION	47,759,638	4,038,869	4,066,342	4,174,003	4,181,121	3,749,673	4,024,142	3,709,575	3,801,291	3,548,355	3,968,629	4,365,160	4,132,477
HYDRO GENERATION													
West Hydro	4,323,248	343,170	515,936	571,027	463,081	556,990	549,496	445,498	189,768	148,284	141,831	179,372	218,795
East Hydro	458,853	25,009	27,947	29,611	26,275	20,180	41,674	33,747	52,856	56,945	59,318	57,682	27,610
TOTAL HYDRO	4,782,101	368,179	543,883	600,638	489,356	577,170	591,169	479,245	242,623	205,229	201,149	237,054	246,405
TOTAL RESOURCES	85,429,281	6,007,906	6,538,593	6,974,053	6,751,160	6,108,948	7,112,014	8,321,042	9,122,201	7,728,309	7,227,347	7,170,994	6,366,714

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GRID Study Results
Resource Statistics
"THE RACK"

Period Ending September 2002

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
FUEL BURNED (Tons, MMBtu)													
Blundell	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	630,772	33,273	54,718	55,358	54,979	46,136	53,824	54,904	56,476	53,404	56,448	56,663	54,589
Cholla	1,369,220	116,609	120,326	114,717	109,873	105,673	84,286	112,193	123,202	108,693	117,313	129,318	127,016
Colstrip	709,904	44,132	38,494	64,109	64,255	57,978	64,120	62,050	63,725	61,949	63,075	64,185	61,832
Craig	593,645	52,418	49,090	50,799	51,141	44,957	50,786	37,383	55,662	44,890	50,332	54,760	51,427
Dave Johnston	3,877,587	341,367	330,302	340,480	341,438	307,890	340,392	330,048	329,543	225,462	321,190	340,921	328,552
Gadsby	3,351,603	178,648	94,334	71,364	39,856	-	65,577	259,067	264,304	452,042	692,700	836,255	397,456
Gadsby CTs	572,106	-	-	-	-	-	-	-	-	-	-	-	572,106
Hayden	236,729	21,337	18,859	19,642	19,914	16,028	10,333	20,043	22,650	19,719	22,525	23,922	21,755
Hermiston	10,999,817	1,184,130	1,207,216	1,219,767	1,186,149	988,183	1,144,964	834,079	903,024	50,198	43,727	1,141,885	1,096,494
Hunter	3,824,555	333,392	330,222	339,732	340,598	305,591	337,196	219,010	310,361	327,804	339,845	339,525	301,280
Huntington	3,072,168	218,135	262,438	269,609	270,063	240,046	269,731	262,710	218,797	257,862	270,393	271,108	261,276
Jim Bridger	5,922,824	531,262	514,875	519,572	537,808	482,968	523,320	494,948	396,682	409,902	467,037	534,001	510,450
Little Mountain	1,662,483	159,504	163,290	177,938	177,940	160,719	168,732	163,290	159,504	141,178	17,008	27,538	145,844
Naughton	2,701,929	234,750	215,691	223,809	227,536	206,768	183,792	238,785	246,730	211,476	233,984	246,722	231,886
West Valley CT	9,648,649	847,478	755,724	757,403	590,565	579,555	780,122	656,865	771,097	773,455	998,654	1,216,840	920,892
Wyodak	1,621,876	147,313	142,535	146,953	147,357	132,935	146,983	90,056	135,490	130,764	135,463	135,330	130,700
BURN RATE (Tons/MWH, MMBtu/MWH)													
Blundell	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	0.474	0.472	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474
Cholla	0.557	0.559	0.554	0.559	0.563	0.558	0.554	0.559	0.555	0.562	0.559	0.552	0.551
Colstrip	0.665	0.665	0.664	0.665	0.664	0.664	0.664	0.665	0.665	0.665	0.666	0.664	0.665
Craig	0.498	0.498	0.498	0.498	0.498	0.498	0.498	0.497	0.497	0.499	0.498	0.497	0.498
Dave Johnston	0.678	0.678	0.678	0.678	0.678	0.678	0.678	0.678	0.677	0.679	0.678	0.678	0.678
Gadsby	14.453	15.528	15.203	15.200	15.691	-	14.736	15.874	15.841	14.564	13.657	13.606	15.129
Gadsby CTs	10.604	-	-	-	-	-	-	-	-	-	-	-	10.604
Hayden	0.505	0.504	0.505	0.505	0.505	0.505	0.505	0.504	0.504	0.505	0.504	0.504	0.504
Hermiston	7.964	7.631	7.702	8.018	8.501	8.552	7.813	7.833	7.763	49.191	285.796	7.658	7.694
Hunter	0.460	0.459	0.460	0.460	0.460	0.460	0.460	0.461	0.460	0.460	0.460	0.460	0.459
Huntington	0.449	0.451	0.449	0.449	0.449	0.449	0.449	0.449	0.448	0.450	0.449	0.449	0.449
Jim Bridger	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.567	0.566	0.563	0.563
Little Mountain	15.886	16.000	15.797	15.618	15.618	15.618	15.797	15.797	16.000	16.303	16.652	16.689	16.303
Naughton	0.556	0.556	0.557	0.557	0.556	0.556	0.558	0.554	0.554	0.558	0.556	0.554	0.555
West Valley CT	11.083	11.122	11.122	11.122	11.122	11.122	11.122	11.083	11.107	11.102	11.042	11.026	10.989
Wyodak	0.743	0.741	0.741	0.741	0.741	0.741	0.741	0.741	0.746	0.747	0.746	0.747	0.747
AVERAGE FUEL COST ($/Ton, $/MMBtu)													
Blundell	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593
Carbon	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344
Cholla	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354
Colstrip	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153
Craig	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010
Dave Johnston	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270
Gadsby	4.279	5.138	4.882	4.893	5.062	5.062	5.062	4.047	4.047	3.378	3.203	3.105	3.470
Gadsby CTs	3.240												3.240
Hayden	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179
Hermiston	2.617	2.493	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628
Hunter	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703
Huntington	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829
Jim Bridger	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784
Little Mountain	4.049	4.908	4.652	4.663	4.832	4.832	4.832	3.817	3.817	3.148	2.973	2.875	3.240
Naughton	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831
West Valley CT	4.049	4.908	4.652	4.663	4.832	4.832	4.832	3.817	3.817	3.148	2.973	2.875	3.240
Wyodak	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411

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PEAK CAPACITY (NAMEPLATE)													
Blundell	23	23	23	23	23	23	23	23	23	23	23	23	23
Carbon	175	175	175	175	175	175	175	175	175	175	175	175	175
Cholla	380	380	380	380	380	380	380	380	380	380	380	380	380
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148	148
Craig	165	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston	772	772	772	772	772	772	772	772	772	772	772	772	772
Gadsby	235	235	235	235	235	235	235	235	235	235	235	235	235
Gadsby CTs	117	-	-	-	-	-	-	-	-	-	-	-	117
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78
Hermiston	245	236	243	245	241	239	238	235	234	231	230	231	233
Hunter	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,117	1,117	1,122
Huntington	895	895	895	895	895	895	895	895	895	895	895	895	895
Jim Bridger	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413
Little Mountain	16	14	15	16	16	16	15	15	14	13	12	12	13
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700
West Valley CT	210	200	205	210	210	210	205	205	200	195	190	190	195
Wyodak	276	276	276	276	276	276	276	276	252	252	252	252	252
CAPACITY FACTOR													
Blundell	82.71	85.22	85.09	83.48	85.44	84.57	83.63	84.94	85.37	83.37	85.22	84.50	61.29
Carbon	86.86	54.12	91.68	89.76	89.12	82.77	87.30	91.98	91.57	89.43	91.51	91.86	91.44
Cholla	73.85	73.76	79.37	72.56	69.06	74.18	53.85	73.32	78.52	70.73	74.29	82.82	84.21
Colstrip	82.38	60.28	54.39	87.62	87.83	87.74	87.63	87.63	87.02	87.47	86.03	87.73	87.30
Craig	82.50	85.79	82.98	83.10	83.67	81.41	83.09	63.29	91.17	75.77	82.32	89.67	86.99
Dave Johnston	84.61	87.72	87.70	87.48	87.74	87.59	87.46	87.63	84.72	59.75	82.50	87.60	87.22
Gadsby	11.26	6.58	3.67	2.69	1.45	0.00	2.55	9.65	9.54	18.34	29.01	35.15	15.53
Gadsby CTs	64.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.05
Hayden	68.66	72.88	66.51	67.02	67.95	60.52	35.29	70.79	77.39	69.57	76.96	81.77	76.81
Hermiston	66.72	88.37	89.58	83.46	77.82	71.94	82.76	62.93	66.82	0.61	0.09	86.76	84.95
Hunter	84.68	86.92	88.94	88.51	88.76	88.11	87.86	58.75	80.79	88.22	88.94	88.85	81.20
Huntington	87.23	72.70	90.67	90.13	90.29	88.84	90.18	90.77	73.37	89.00	90.39	90.64	90.25
Jim Bridger	84.90	89.76	89.91	87.72	90.90	90.37	88.37	86.41	66.96	71.09	78.45	90.23	89.09
Little Mountain	83.90	95.71	95.71	95.71	95.71	95.71	95.71	95.71	95.71	92.52	11.44	18.48	95.58
Naughton	79.26	81.10	76.79	77.16	78.54	79.07	63.24	85.49	85.49	75.16	80.81	85.47	82.88
West Valley CT	49.40	51.21	46.04	43.59	33.99	36.93	45.99	40.16	46.66	49.62	63.98	78.07	59.69
Wyodak	93.65	96.79	96.77	96.54	96.82	96.69	96.56	61.13	96.81	96.52	96.79	96.68	96.48

PacifiCorp
Period Ending September 2002

GRID Results
Net Power Cost Analysis
($)

Exhibit ICNU 104 Pt. 2
Run W/O West Valley

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
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SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
AEPCO	785,051	-	-	-	-	-	-	-	-	-	376,320	408,731	-
Black Hills	11,819,968	1,195,222	1,165,234	1,197,803	1,089,602	959,028	234,934	1,022,672	1,052,735	844,149	898,965	1,089,891	1,069,736
Black Hills Capacity	1,080,000	180,000	180,000	180,000	180,000	180,000	180,000	-	-	-	-	-	-
BPA Flathead Sale	21,523,320	1,828,008	1,769,040	1,828,008	1,828,008	1,651,104	1,828,008	1,769,040	1,828,008	1,769,040	1,828,008	1,828,008	1,769,040
BPA Wind	2,267,141	225,722	254,827	257,737	236,812	194,765	201,023	180,371	138,883	144,286	145,470	133,763	153,483
CDWR	34,901,964	3,299,264	3,266,576	3,331,952	2,684,524	2,622,640	3,108,544	2,718,904	2,684,524	2,650,144	2,684,524	2,787,664	3,062,704
Clark Storage & Integration	4,706,081	647,320	999,907	761,255	159,852	227,329	294,963	237,627	330,979	205,127	186,168	319,320	336,236
Clark Wafertech	1,428,480	121,112	117,560	121,112	121,112	110,456	121,112	117,560	121,112	117,560	121,112	121,112	117,560
Citizens Power	3,390,938	297,891	419,755	246,437	463,557	436,289	-	292,570	307,968	410,625	451,687	64,160	-
COPD (BHP Steel)	862,772	125,936	122,180	125,936	125,936	114,668	125,936	122,180	-	-	-	-	-
Deseret Supplemental	7,056,868	576,203	497,815	582,801	486,464	445,622	762,743	555,543	520,553	545,360	690,041	754,265	639,458
Deseret Displacement	223,117	40,004	1,110	3,690	23	7,065	23,010	392	19,477	28,328	28,327	28,665	43,026
Flathead	6,377,280	541,632	524,160	541,632	541,632	489,216	541,632	524,160	541,632	524,160	541,632	541,632	524,160
Hurricane Sale	293,888	14,168	8,708	18,592	31,500	28,112	28,252	27,636	30,940	25,564	27,720	28,644	24,052
LADWP (IPP Layoff)	26,187,080	2,383,946	2,566,920	2,286,498	1,991,266	1,956,721	1,991,266	2,032,767	2,231,396	2,193,978	2,186,754	2,214,048	2,151,520
PSCO	54,875,495	4,716,380	4,481,726	4,702,296	4,520,489	4,305,779	4,702,172	4,447,816	4,520,487	4,525,446	4,692,259	4,702,168	4,558,478
Puget Sound	53,166,656	4,454,320	4,399,664	4,454,320	4,249,176	4,621,520	4,792,320	4,409,728	4,344,824	3,999,808	4,033,968	4,669,344	4,737,664
SCE	59,921,106	5,360,369	5,071,160	5,329,577	4,992,000	4,608,000	4,992,000	4,992,000	4,992,000	4,800,000	4,992,000	5,184,000	4,608,000
SDG&E Sale	3,632,160	1,223,880	1,184,400	1,223,880	-	-	-	-	-	-	-	-	-
Sierra Pac 2	24,733,908	2,236,397	2,080,710	2,284,713	1,974,788	1,920,779	2,165,408	1,998,615	1,936,664	1,849,296	1,998,615	2,165,408	2,122,518
SMUD	5,412,444	583,311	525,133	595,559	133,386	103,917	1,153,944	539,748	406,362	139,590	232,650	319,506	679,338
Springfield	9,458,754	840,856	897,997	920,536	719,166	665,415	719,166	593,308	610,916	593,308	610,916	1,464,052	823,117
Springfield II	(3,449,152)	(447,936)	(435,968)	(658,568)	(571,536)	(508,032)	(550,368)	(276,744)	-	-	-	-	-
UMPA	2,485,258	213,774	195,106	212,122	193,454	189,655	224,182	203,532	196,923	193,454	212,688	229,760	220,608
UMPA II	5,202,161	60,840	42,060	255,511	144,832	67,266	75,179	30,501	65,134	642,260	921,127	1,343,408	1,554,042
WAPA I	14,856,960	1,261,824	1,221,120	1,261,824	1,261,824	1,139,712	1,261,824	1,221,120	1,261,824	1,221,120	1,261,824	1,261,824	1,221,120
Total Long Term Firm Sales	353,199,698	31,980,442	31,556,899	32,065,222	27,557,865	26,537,025	28,977,247	27,761,045	28,143,342	27,422,602	29,122,776	31,659,371	30,415,860
Short Term Firm Sales													
COB	42,251,261	4,606,086	4,067,000	4,130,300	675,200	1,428,120	645,600	3,201,701	8,749,360	9,626,000	4,670,350	265,200	186,344
DSW	353,116,977	12,833,770	17,331,640	13,901,516	12,377,020	11,687,270	24,107,600	50,803,374	64,056,658	44,151,700	30,654,804	39,723,414	31,488,211
East Main	4,558,623	156,500	-	-	-	178,752	674,784	1,634,983	411,624	114,887	1,078,631	210,787	97,674
Mid C	232,094,577	22,948,101	25,476,440	28,214,568	12,875,164	11,171,240	23,895,168	40,360,964	32,856,060	17,054,800	9,115,816	4,025,910	4,100,346
West Main	2,349,678	220,212	731,542	212,056	220,212	195,744	212,056	557,856	-	-	-	-	-
Wyoming	1,968,075	3,596	5,604	5,286	4,283	4,011	4,056	331,638	3,971	7	967,207	7	638,407
Total Short Term Firm Sales	636,339,191	40,768,266	47,612,225	46,463,726	26,151,879	24,665,137	49,539,264	96,890,516	106,077,673	70,947,394	46,486,809	44,225,319	36,510,983
System Balancing Sales													
COB	24,425,162	1,200,833	3,044,141	4,405,340	2,630,730	2,244,736	3,241,182	1,711,187	725,953	80,777	1,329,858	2,029,426	1,780,998
DSW	30,136,241	1,869,931	2,363,020	5,112,736	4,366,786	1,949,109	475,829	2,352,740	1,221,160	3,741,996	3,199,425	1,958,295	1,525,215
Mid C	12,957,761	453,305	328,396	1,495,413	441,816	357,412	446,012	718,241	1,293,556	425,816	1,063,764	3,072,960	2,861,071
Trapped Energy	35,853	-	-	-	-	-	-	58	1,118	34,028	321	-	328
Total System Balancing Sales	67,555,016	3,524,068	5,735,557	11,013,488	7,439,333	4,551,257	4,163,023	4,782,226	3,241,787	4,282,616	5,593,368	7,060,681	6,167,611
TOTAL SPECIAL SALES	1,057,093,905	76,272,777	84,904,681	89,542,436	61,149,077	55,753,419	82,679,534	129,433,787	137,462,803	102,652,612	81,202,953	82,945,371	73,094,454

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PURCHASED POWER & NET INTERCHANGE		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Long Term Firm Purchases													
Aquila hydro hedge	1,750,002	145,837	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833	145,833
APS Supplemental Purchase	233,571	233,571	-	-	-	-	-	-	-	-	-	-	-
Avista Summer Capacity	5,378,184	-	-	-	-	-	-	-	-	558,012	1,134,150	1,992,114	1,693,908
Black Hills CTs	1,375,594	69,582	136,676	97,725	120,699	127,125	96,587	122,400	122,400	122,400	120,000	120,000	120,000
BPA Entitlement Capacity	24,069	2,145	2,145	2,145	2,145	2,145	2,145	1,863	1,863	1,863	1,870	1,870	1,870
BPA FC IV Exchange	2,799	262	296	299	301	247	255	229	176	183	185	170	195
BPA Peaking	58,719,000	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250	4,893,250
BPA So. Idaho Exchange	(314,565)	-	-	-	-	-	-	(17,744)	(11,626)	(60,527)	(100,911)	(63,516)	(60,242)
BPA Supplemental Capacity	24,069	2,145	2,145	2,145	2,145	2,145	2,145	1,863	1,863	1,863	1,870	1,870	1,870
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark S&I Purchases	7,643,934	370,370	470,278	775,766	921,098	801,027	1,015,777	423,691	1,199,217	279,003	324,607	496,567	566,533
Colockum Capacity Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Constellation temperature hed	687,918	-	-	-	-	-	-	-	-	143,564	156,854	193,750	193,750
Deseret G&T Expansion	3,401,959	298,932	279,926	335,596	278,538	250,753	391,010	170,724	260,601	205,330	268,987	322,363	339,200
Deseret G&T Non Firm	1,406,930	253,833	8,060	4,330	3,163	11,121	103,517	243,526	41,948	61,179	286,017	183,680	206,556
Deseret Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas PUD Settlement	1,012,916	41,310	55,653	51,507	92,253	78,464	41,553	130,369	178,701	205,596	31,331	49,527	56,652
Element Re temperature hedg	242,920	-	-	-	-	-	-	-	-	(387,200)	80,120	275,000	275,000
Enron Purchase	863,200	448,200	415,000	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreeme	-	-	-	-	-	-	-	-	-	-	-	-	-
Fort James	17,421,891	1,436,476	1,390,138	1,436,476	1,494,223	1,349,620	1,494,223	1,446,022	1,494,223	1,446,022	1,494,223	1,494,223	1,446,022
Gemstate	2,273,521	207,400	19,221	205,100	205,700	201,800	206,700	201,800	201,800	201,800	207,400	207,400	207,400
Grant County	3,068,380	206,780	165,620	213,150	223,930	174,930	203,840	259,700	327,320	349,860	360,150	334,670	248,430
Hermiston Purchase	69,010,625	6,454,841	6,605,621	6,389,890	5,951,240	5,649,465	6,457,941	5,674,974	5,835,868	3,555,692	3,538,301	6,492,937	6,403,855
Idaho Power RTSA return	-	-	-	-	-	-	-	-	-	-	-	-	-
IPP Purchase	26,187,080	2,383,946	2,566,920	2,286,498	1,991,266	1,956,721	1,991,266	2,032,767	2,231,396	2,193,978	2,186,754	2,214,048	2,151,520
MagCorp	1,324,896	-	-	-	-	-	-	-	-	289,044	404,694	399,261	231,898
Mid Columbia	16,077,307	1,271,410	1,254,440	1,497,657	1,257,593	1,239,924	1,266,453	922,516	1,289,779	2,403,006	1,214,012	1,225,873	1,234,644
Morgan Stanley call	2,916,000	-	-	-	-	-	-	-	-	773,000	773,000	685,000	685,000
NuCor	1,207,500	94,500	94,500	94,500	94,500	94,500	105,000	105,000	105,000	105,000	105,000	105,000	105,000
P4 Production	1,287,500	115,000	115,000	115,000	115,000	115,000	-	-	-	-	-	475,000	237,500
PGE Cove	193,503	18,500	18,500	18,500	18,500	18,500	2,481	23,522	15,000	15,000	15,000	15,000	15,000
PSCO FC III Storage Agreeme	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Biomass	16,669,448	1,604,231	1,606,575	1,605,160	1,561,509	1,157,870	1,157,870	1,157,870	1,157,870	1,157,870	1,387,886	1,560,092	1,554,645
QF D.R. Johnson	6,298,439	545,661	228,878	116,831	593,223	548,367	596,400	411,659	658,165	629,700	666,215	648,829	654,511
QF Hydro East	3,244,992	251,712	196,239	328,193	264,489	216,734	190,756	315,130	321,287	482,887	263,193	202,387	211,985
QF Hydro West	17,406,450	900,994	1,046,772	1,396,139	2,079,242	1,249,752	1,679,894	2,071,491	1,994,771	1,733,588	1,132,684	1,093,291	1,027,832
QF Other	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Sunnyside	29,767,162	4,288,962	5,149,137	5,292,500	1,711,736	1,628,561	1,323,585	1,684,011	1,711,736	1,684,011	1,774,222	1,774,222	1,744,481
QF Warm Springs (Pelton)	1,858,130	491,028	671,628	695,474	-	-	-	-	-	-	-	-	-
Rock River	5,860,602	-	559,421	707,219	711,623	585,209	603,973	542,001	417,315	433,599	437,077	401,921	461,244
SCE Firm Capacity	4,415,357	950,140	1,732,608	1,732,608	-	-	-	-	-	-	-	-	-
Sempra call	3,415,300	-	-	-	-	-	-	-	-	712,680	1,061,080	1,066,540	575,000
SF Phosphates	5,755,347	620,160	1,094,400	1,130,880	330,429	298,452	330,429	319,770	330,429	319,770	330,429	330,429	319,770
Small Purchases east	421,304	28,618	32,788	42,101	55,843	39,043	38,190	38,035	35,321	33,301	33,712	22,361	21,991
Small Purchases west	322,838	1,137	10,415	2,807	3,590	4,338	3,859	3,129	1,043	1,460	215,320	75,319	421
TransAlta Purchase	81,459,264	6,326,309	6,127,778	6,336,133	5,658,434	5,108,576	5,658,432	3,808,204	3,937,794	3,811,258	11,689,104	11,680,038	11,317,206
Tri-State Purchase	11,117,698	982,919	922,285	994,587	844,761	872,091	1,163,420	890,324	886,098	767,360	774,122	942,085	1,077,647
DSM (Load Curtailment)	9,644,182	1,420,362	782,597	39,037	46,282	-	1,159,890	1,015,740	1,049,598	1,015,740	1,049,598	1,049,598	1,015,740
Total Long Term Firm Purchases	421,110,718	37,362,156	38,803,943	38,986,572	31,677,273	28,824,570	32,329,267	29,041,589	30,838,566	30,288,919	38,460,153	43,111,265	41,386,446

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		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Short Term Firm Purchases													
COB	50,733,164	10,814,869	10,286,000	11,164,850	-	-	703,513	4,073,353	6,701,930	4,668,300	2,320,350	-	-
DSW	357,770,749	4,555,389	6,263,150	7,522,430	5,033,600	4,926,020	13,489,240	45,803,231	60,331,548	43,935,366	56,918,074	62,606,094	46,386,607
East Main	11,874,494	-	252,000	-	-	213,600	-	987,929	580,450	2,361,338	3,677,649	2,243,978	1,557,550
Mid C	255,968,387	12,123,383	16,605,420	23,308,512	15,544,254	9,648,060	19,722,868	40,870,656	39,073,408	31,823,960	18,956,440	16,135,360	12,156,066
West Main	7,983,895	250,796	213,200	435,800	507,600	855,358	936,260	921,225	447,460	716,800	2,509,170	120,507	69,720
Wyoming	81,600	-	-	-	-	-	63,000	-	18,600	-	-	-	-
Total Short Term Firm Purchases	684,412,290	27,744,436	33,619,770	42,431,592	21,085,454	15,643,038	34,914,881	92,656,394	107,153,396	83,505,764	84,381,683	81,105,939	60,169,943
System Balancing Purchases													
COB	11,017,182	922,590	449,026	668,168	1,073,995	389,385	1,389,992	179,785	1,453,142	2,907,922	418,543	816,888	347,747
DSW	21,226,049	1,023,803	947,895	189,818	174,964	558,844	6,600,041	482,535	1,612,093	1,505,612	1,457,936	4,883,539	1,788,969
Mid C	46,324,734	6,249,578	7,421,514	5,939,834	4,462,779	4,199,553	5,248,350	5,287,297	3,473,171	608,318	627,190	1,429,991	1,377,158
Emergency Purchases	628,098	-	-	-	-	-	-	-	-	-	174,734	453,364	-
Total System Balancing Purchas	79,196,063	8,195,971	8,818,435	6,797,820	5,711,738	5,147,781	13,238,383	5,949,618	6,538,406	5,021,852	2,678,403	7,583,782	3,513,874
TOTAL PURCHASED PW & NET I	1,184,719,071	73,302,562	81,242,149	88,215,984	58,474,465	49,615,389	80,482,530	127,647,600	144,530,368	118,816,535	125,520,240	131,800,986	105,070,263
WHEELING & U. OF F. EXPENSE													
Firm Wheeling	89,883,670	8,020,818	8,529,696	9,160,576	9,127,962	8,240,627	7,483,911	6,437,098	5,557,935	8,395,605	6,347,367	6,334,708	6,247,367
Non-Firm Wheeling	1,417,396	72,124	106,439	118,002	107,314	87,183	122,598	89,589	92,053	170,570	180,787	180,051	90,686
TOTAL WHEELING & U. OF F. EX	91,301,066	8,092,942	8,636,135	9,278,578	9,235,276	8,327,810	7,606,509	6,526,687	5,649,988	8,566,175	6,528,154	6,514,759	6,338,053
THERMAL FUEL BURN EXPENSE													
Blundell	3,764,784	329,477	318,370	322,755	330,317	295,315	323,315	317,810	330,037	311,928	329,477	326,676	229,307
Carbon	10,796,535	575,977	940,033	948,286	938,440	766,308	888,431	949,004	975,564	922,000	968,904	977,610	945,978
Cholla	31,699,419	2,644,833	2,788,912	2,714,352	2,617,026	2,517,823	1,989,950	2,620,344	2,814,664	2,462,736	2,687,283	2,915,782	2,925,715
Colstrip	7,208,069	448,058	390,818	650,884	652,368	588,639	650,993	629,975	647,244	628,950	640,380	651,653	628,108
Craig	11,391,723	1,019,245	941,916	955,544	943,171	848,151	976,111	717,706	1,063,460	870,348	981,472	1,075,869	998,729
Dave Johnston	43,696,871	3,847,053	3,722,348	3,836,945	3,847,560	3,467,422	3,836,066	3,719,512	3,714,083	2,540,854	3,620,369	3,842,023	3,702,635
Gadsby	12,349,358	917,862	460,506	349,204	201,738	-	331,927	1,050,179	1,069,550	1,590,477	2,266,767	2,642,515	1,468,633
Gadsby CTs	1,758,021	-	-	-	-	-	-	-	-	-	-	-	1,758,021
Hayden	5,347,224	500,977	444,896	448,368	445,675	360,611	234,829	445,459	485,109	437,156	510,239	543,946	489,959
Hermiston	36,948,851	3,653,179	3,870,325	3,893,705	3,789,670	3,278,704	3,698,785	2,879,889	3,052,976	799,448	782,440	3,688,087	3,561,645
Hunter	67,655,596	5,901,849	5,843,709	6,002,650	6,022,407	5,390,752	5,958,016	3,877,034	5,493,368	5,802,986	6,015,894	6,010,341	5,336,588
Huntington	57,706,360	4,110,357	4,935,507	5,063,076	5,072,100	4,462,585	5,022,111	4,944,077	4,118,289	4,856,992	5,093,942	5,106,645	4,920,678
Jim Bridger	99,775,703	8,953,754	8,666,089	8,766,761	9,063,230	8,109,255	8,803,977	8,321,129	6,675,842	6,910,911	7,884,914	9,017,962	8,601,879
Little Mountain	7,121,442	782,814	759,570	829,770	859,745	776,540	815,254	623,222	608,773	444,442	53,438	95,339	472,533
Naughton	53,929,010	4,754,384	4,300,212	4,407,122	4,494,680	4,116,223	3,723,216	4,731,377	4,856,529	4,292,758	4,662,362	4,932,879	4,657,269
West Valley CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	15,263,838	1,386,391	1,341,427	1,383,006	1,386,814	1,251,077	1,383,288	847,535	1,275,122	1,230,646	1,274,872	1,273,617	1,230,043
TOTAL FUEL BURN EXPENSE	466,412,805	39,826,210	39,724,638	40,572,428	40,664,940	36,229,407	38,636,269	36,674,253	37,180,611	34,102,632	37,772,753	43,100,945	41,927,719
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NET POWER COST	685,339,036	44,948,937	44,698,241	48,524,553	47,225,604	38,419,186	44,045,774	41,414,753	49,898,164	58,832,730	88,618,194	98,471,319	80,241,581
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Net Power Cost/Net System	***12.86***	***10.64***	***10.19***	***10.34***	***9.87***	***9.17***	***10.22***	***10.20***	***11.52***	***13.32***	***18.40***	***20.26***	***18.98***

PacifiCorp | **GRID Results** | **Base Case 2002-09-25**

Net Power Cost Energy Analysis

Period Ending September 2002 | (MWH)

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
NET SYSTEM LOAD	53,307,530	4,224,160	4,388,624	4,693,252	4,782,342	4,191,171	4,310,301	4,061,804	4,330,878	4,418,307	4,817,333	4,860,848	4,228,508
SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
AEPCO	15,615	-	-	-	-	-	-	-	-	-	6,840	8,775	-
Black Hills	414,469	40,833	38,048	41,072	36,422	33,601	38,114	35,179	37,970	19,452	19,575	38,112	36,092
BPA Flathead Sale	472,986	40,176	38,880	40,176	40,176	36,288	40,176	38,880	40,176	38,880	40,176	40,176	38,826
BPA Wind	46,475	4,349	4,910	4,966	4,996	4,109	4,241	3,805	2,930	3,044	3,069	2,822	3,234
CDWR	614,900	58,600	57,400	59,800	44,700	42,000	63,200	46,200	44,700	43,200	44,700	49,200	61,200
Clark Storage & Integration	176,888	17,790	30,111	23,589	5,623	8,428	12,427	14,020	19,797	12,956	9,575	10,380	12,192
Clark Wafertech	87,590	7,440	7,200	7,440	7,440	6,720	7,440	7,200	7,440	7,200	7,440	7,440	7,190
Citizens Power	105,910	9,350	13,175	7,735	14,450	13,600	-	9,120	9,600	12,800	14,080	2,000	-
COPD (BHP Steel)	50,880	7,440	7,200	7,440	7,440	6,720	7,440	7,200	-	-	-	-	-
Deseret Supplemental	328,463	27,900	27,000	27,900	27,900	25,200	27,900	27,000	27,900	27,000	27,900	27,900	26,963
Deseret Displacement	29,749	5,334	148	492	3	942	3,068	52	2,597	3,777	3,777	3,822	5,737
Flathead	140,144	11,904	11,520	11,904	11,904	10,752	11,904	11,520	11,904	11,520	11,904	11,904	11,504
Hurricane Sale	10,495	506	311	664	1,125	1,004	1,009	987	1,105	913	990	1,023	858
LADWP (IPP Layoff)	539,002	46,290	49,843	44,398	42,855	38,707	42,855	42,583	48,023	45,960	46,312	46,890	44,286
PSCO	1,156,355	102,080	91,520	101,446	94,336	85,184	102,080	91,238	94,336	94,547	101,658	102,080	95,850
Puget Sound	1,053,200	104,000	100,800	104,000	72,200	94,000	104,000	81,600	77,800	57,600	59,600	96,800	100,800
SCE	962,600	77,700	72,000	76,900	83,200	76,800	83,200	83,200	83,200	80,000	83,200	86,400	76,800
SDG&E Sale	220,800	74,400	72,000	74,400	-	-	-	-	-	-	-	-	-
Sierra Pac 2	460,575	42,525	36,000	44,550	35,625	33,075	44,625	36,750	33,825	29,700	36,750	44,625	42,525
SMUD	350,400	38,100	34,300	38,900	8,600	6,700	74,400	34,800	26,200	9,000	15,000	20,600	43,800
Springfield	210,269	19,040	18,432	19,040	14,875	13,425	14,875	14,400	14,875	14,400	14,875	33,600	18,432
UMPA	41,760	3,960	3,056	3,880	2,976	2,792	4,464	3,464	3,144	2,976	3,304	4,080	3,664
UMPA II	132,119	2,160	1,440	9,407	4,768	2,723	3,570	1,347	2,716	23,596	18,308	29,524	32,560
WAPA I	464,227	39,432	38,160	39,432	39,432	35,616	39,432	38,160	39,432	38,160	39,432	39,432	38,107
Total Long Term Firm Sales	8,085,871	781,309	753,455	789,532	601,045	578,386	730,421	628,706	629,671	576,680	608,465	707,584	700,619
Short Term Firm Sales													
COB	1,413,025	109,875	94,400	94,400	33,600	79,200	37,200	107,175	328,000	322,000	183,200	15,600	8,375
DSW	11,533,475	428,025	629,000	462,000	472,400	523,400	964,000	1,679,125	2,182,120	1,364,200	823,680	1,033,800	971,725
East Main	300,129	7,825	-	-	-	8,400	31,340	64,040	15,540	13,075	68,392	48,408	43,109
Mid C	7,259,616	276,725	385,600	464,096	486,440	483,200	895,200	1,521,660	1,439,760	702,400	349,560	141,000	113,975
West Main	117,424	10,800	44,624	10,400	10,800	9,600	10,400	20,800	-	-	-	-	-
Wyoming	66,024	27	43	43	37	36	38	12,436	37	720	31,944	744	19,919
Short Term Firm Sales	20,689,693	833,277	1,153,667	1,030,939	1,003,277	1,103,836	1,938,178	3,405,236	3,965,457	2,402,395	1,456,776	1,239,552	1,157,103
System Balancing Sales													
COB	1,037,165	51,095	125,622	174,845	131,995	104,769	95,336	74,728	41,372	5,206	66,653	94,247	71,299
DSW	1,165,314	72,814	88,123	183,532	190,554	85,716	15,532	82,068	46,330	134,852	125,103	85,550	55,142
Mid C	730,069	22,142	16,399	68,668	23,601	18,501	14,467	43,198	74,393	84,022	98,130	144,507	122,040
Trapped Energy	79,252	-	-	-	-	-	-	33	716	77,918	377	-	207
Total System Balancing Sales	3,011,800	146,051	230,144	427,045	346,150	208,986	125,334	200,027	162,811	301,998	290,262	324,304	248,687
TOTAL SPECIAL SALES	31,787,364	1,760,636	2,137,265	2,247,515	1,950,473	1,891,208	2,793,933	4,233,969	4,757,939	3,281,074	2,355,503	2,271,440	2,106,409
TOTAL REQUIREMENTS	85,094,894	5,984,797	6,525,890	6,940,767	6,732,815	6,082,379	7,104,234	8,295,774	9,088,817	7,699,380	7,172,836	7,132,288	6,334,917

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PURCHASED POWER & NET INTERCHANGE		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Long Term Firm Purchases													
APS Exchange	-	78,240	138,240	142,560	142,560	69,120	-	-	(78,240)	(138,240)	(142,560)	(142,560)	(69,120)
APS Supplemental Purchase	12,250	12,250	-	-	-	-	-	-	-	-	-	-	-
Avista Seasonal Exch	-	-	-	(18,600)	(4,300)	(4,700)	-	-	-	-	50	18,550	9,000
Avista Summer Capacity	82,800	-	-	-	-	-	-	-	-	5,400	11,250	32,550	33,600
BPA Exchange	93	(66,666)	(66,667)	-	-	-	(50,000)	-	-	133,898	116,102	-	(66,574)
BPA FC II Storage Agreement	320	183	111	42	38	(93)	47	(35)	(100)	37	24	(14)	80
BPA FC IV Storage Agreemen	2,993	1,712	1,030	392	362	(875)	443	(321)	(929)	343	229	(135)	743
BPA Peaking	15,263	19,333	(13,135)	17,113	(29,785)	-	22,015	(24,513)	27,935	(38,480)	6,568	12,950	15,263
BPA So. Idaho Exchange	51,772	1,461	2,413	2,796	2,653	1,347	419	2,587	1,891	7,734	12,700	8,123	7,647
BPA Supplemental Capacity	28	8	(80)	176	(376)	(8)	288	(192)	192	(192)	(184)	280	116
Canadian Entitlement	(74,399)	(6,399)	(6,168)	(6,207)	(6,399)	(5,706)	(6,207)	(6,168)	(6,399)	(5,976)	(6,399)	(6,399)	(5,971)
Clark S&I Purchases	362,444	14,580	16,598	28,912	45,030	40,154	39,665	24,190	77,162	15,542	18,313	19,002	23,296
Colockum Capacity Exchange	(199,332)	(13,797)	(18,018)	(15,498)	(19,404)	(17,955)	(378)	(18,585)	(19,278)	(20,160)	(19,656)	(18,774)	(17,829)
Cowlitz Swift	25,621	(20)	(58)	(5)	(5)	(47)	(47)	(6)	6,315	6,131	5,270	3,385	4,708
CSPE	79,364	6,354	6,138	7,470	7,470	6,732	6,336	6,000	6,208	6,016	7,312	7,312	6,016
Deseret G&T Expansion	216,485	18,201	18,668	20,068	19,134	16,801	17,267	11,667	19,134	18,668	19,134	18,201	19,543
Deseret G&T Non Firm	69,096	14,265	496	240	205	719	4,760	13,104	2,438	3,012	12,201	7,737	9,921
Douglas PUD Settlement	78,001	3,631	4,447	5,164	7,213	7,002	7,327	7,252	9,489	9,537	6,795	5,899	4,247
Enron Purchase	20,800	10,800	10,000	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreemei	1,544	145	163	165	165	137	141	126	98	101	101	94	108
Foote Creek I	121,711	11,389	12,858	13,004	13,085	10,761	11,106	9,966	7,673	7,973	8,037	7,390	8,469
Fort James	373,484	31,724	30,701	31,724	31,724	28,654	31,724	30,701	31,724	30,701	31,724	31,724	30,658
Gemstate	34,628	-	-	-	-	-	-	-	2,992	12,254	10,956	8,426	-
Grant County	87,668	5,908	4,732	6,090	6,398	4,998	5,824	7,420	9,352	9,996	10,290	9,562	7,098
Hermiston Purchase	1,393,741	157,356	158,987	153,283	139,723	116,094	148,456	107,924	117,161	1,020	153	150,228	143,355
Hurricane Purchase	1,047	51	100	48	148	94	81	60	79	92	88	102	104
Idaho Power RTSA Return	(78,329)	(6,840)	(7,200)	(7,160)	(7,416)	(6,624)	(6,584)	(4,896)	(4,944)	(6,560)	(8,336)	(5,976)	(5,793)
IPP Purchase	539,002	46,290	49,843	44,398	42,855	38,707	42,855	42,583	48,023	45,960	46,312	46,890	44,286
MagCorp	34,808	-	-	-	-	-	-	-	-	8,400	9,776	9,720	6,912
Mid Columbia	2,170,403	165,697	130,306	155,671	263,465	245,300	195,191	109,041	151,396	212,065	221,829	175,009	145,433
Morgan Stanley call	3,200	-	-	-	-	-	-	-	-	1,600	1,600	-	-
PGE Cove	14,603	2,038	1,973	1,611	1,014	942	1,014	990	1,014	990	1,014	1,014	989
PSCO FC III Storage Agreeme	294	3,114	3,401	1,262	206	(1,703)	(1,499)	(601)	(2,626)	(1,506)	299	(432)	379
QF Biomass	97,765	10,765	12,995	14,616	14,823	19	-	-	-	-	15,656	14,971	13,920
QF D.R. Johnson	62,930	4,185	5,400	5,580	5,022	5,040	5,580	5,400	5,580	4,590	5,580	5,580	5,393
QF Hydro East	61,227	4,736	3,717	6,131	5,281	3,777	3,609	5,903	5,990	9,199	5,010	3,852	4,022
QF Hydro West	187,554	9,010	10,955	15,497	21,980	13,434	17,944	22,555	22,496	18,772	12,298	11,762	10,851
QF Other	-	-	-	-	-	-	-	-	-	-	-	-	-
QF Sunnyside	385,013	26,865	33,581	34,700	34,700	31,342	19,029	33,581	34,700	33,581	34,700	34,700	33,534
QF Warm Springs (Pelton)	19,797	6,203	6,386	7,208	-	-	-	-	-	-	-	-	-
Redding Exchange	17,262	(9,164)	(4,397)	10,755	8,610	7,852	750	(2,678)	(1,025)	6,108	5,253	3,058	(7,860)
Rock River	165,162	-	15,767	19,933	20,057	16,494	17,023	15,276	11,762	12,221	12,319	11,328	12,982
SCE Firm Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line Storage Agree	80,688	-	-	-	45,816	38,410	(7,508)	1,602	8,660	6,103	(3,381)	(969)	(8,045)
Sempra call	25,600	-	-	-	-	-	-	-	-	3,200	11,200	11,200	-
SF Phosphates	77,211	3,264	5,760	5,952	7,068	6,384	7,068	6,840	7,068	6,840	7,068	7,068	6,831
Small Purchases east	6,867	481	538	662	890	538	590	663	630	589	589	319	378
Small Purchases west	8,433	71	356	193	230	302	259	212	70	98	5,635	1,521	(514)
TransAlta Purchase	2,764,028	216,432	209,640	216,768	216,600	195,552	216,600	209,472	216,600	209,640	288,800	288,576	279,348
Tri-State Exchange	(850)	26,000	25,200	26,000	26,000	23,500	26,000	(25,200)	(26,000)	(25,200)	(26,000)	(26,000)	(25,150)
Tri-State Purchase	284,810	31,123	26,900	31,935	17,408	19,105	37,200	20,238	19,975	12,600	13,020	23,453	31,855
Total Long Term Firm Purchases	9,684,899	840,976	832,676	980,648	1,080,248	911,601	814,388	612,158	714,266	624,697	768,738	790,277	714,226
Short Term Firm Purchases													
COB	979,875	111,750	108,000	130,800	-	-	23,750	138,175	252,200	142,000	73,200	-	-
DSW	8,719,620	124,000	198,600	232,800	194,200	219,000	517,600	1,452,325	1,958,880	1,277,240	859,400	969,800	715,775
East Main	324,924	-	8,400	-	-	9,936	744	33,757	20,816	74,827	85,812	51,731	38,901
Mid C	9,634,623	224,200	400,800	595,800	507,400	390,000	768,400	1,601,418	1,834,680	1,412,000	889,400	582,400	428,125
West Main	497,614	11,545	16,160	13,376	13,776	27,408	30,116	29,454	19,716	57,280	264,216	10,056	4,512
Wyoming	3,840	-	-	-	-	-	2,640	-	1,200	-	-	-	-
Total Short Term Firm Purchases	20,160,496	471,495	731,960	972,776	715,376	646,344	1,343,250	3,255,128	4,087,492	2,963,347	2,172,028	1,613,987	1,187,313
System Balancing Purchases													
COB	601,768	36,930	22,303	31,285	61,879	19,360	44,003	7,555	60,866	238,756	25,659	38,372	14,800

DSW	801,428	43,091	54,731	8,205	11,369	29,324	203,510	30,601	89,829	115,530	47,974	110,509	56,757
Mid C	2,122,137	246,989	335,135	239,385	246,641	208,425	152,429	257,754	169,360	63,264	70,364	74,833	57,556
Emergency Purchases	5,273	-	-	-	-	-	-	-	-	-	1,495	3,778	-
Total System Balancing Purchas	3,530,605	327,010	412,169	278,875	319,889	257,110	399,942	295,909	320,055	417,550	145,492	227,492	129,112
TOTAL PURCHASED PW & NET I	33,375,999	1,639,481	1,976,805	2,232,298	2,115,513	1,815,054	2,557,580	4,163,196	5,121,813	4,005,594	3,086,258	2,631,756	2,030,651
THERMAL GENERATION													
Blundell	166,635	14,583	14,092	14,286	14,620	13,071	14,310	14,067	14,608	13,806	14,583	14,459	10,149
Carbon	1,314,100	70,324	114,425	115,409	114,181	93,145	108,158	115,505	118,747	112,170	117,934	118,985	115,116
Cholla	2,435,887	201,952	215,405	208,198	199,681	193,757	154,081	200,765	216,763	187,159	205,717	225,387	227,023
Colstrip	1,068,142	66,370	57,959	96,477	96,715	87,260	96,494	93,374	95,867	93,210	94,731	96,600	93,084
Craig	1,203,947	107,752	99,515	100,936	99,618	89,580	103,148	75,938	112,493	91,839	103,703	113,822	105,604
Dave Johnston	5,721,877	503,823	487,489	502,457	503,898	454,116	502,343	487,104	486,653	332,103	473,935	503,139	484,818
Gadsby	238,870	11,505	6,205	4,695	2,540	-	4,450	16,363	16,685	32,782	52,132	62,830	28,684
Gadsby CTs	50,320	-	-	-	-	-	-	-	-	-	-	-	50,320
Hayden	477,859	44,790	39,742	40,036	39,785	32,184	20,989	39,837	43,359	39,052	45,622	48,657	43,805
Hermiston	1,393,741	157,356	158,987	153,283	139,723	116,094	148,456	107,924	117,161	1,020	153	150,228	143,355
Hunter	8,310,112	725,564	718,193	737,312	739,959	661,770	731,883	474,631	674,298	712,680	739,090	738,353	656,380
Huntington	6,822,134	484,503	583,582	598,573	599,690	527,455	593,749	584,610	488,410	573,744	602,242	603,828	581,747
Jim Bridger	10,551,979	947,924	917,598	927,535	959,870	858,608	931,534	880,821	706,031	726,840	829,979	954,847	910,391
Little Mountain	105,045	9,969	10,337	11,393	11,393	10,291	10,681	10,337	9,969	8,660	1,079	1,989	8,946
Naughton	4,894,531	431,970	389,371	399,010	407,460	373,486	336,931	430,579	441,830	388,363	423,064	449,085	423,383
West Valley CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	2,181,615	198,748	192,300	198,233	198,813	179,340	198,276	121,480	181,505	175,127	181,466	181,270	175,057
TOTAL THERMAL GENERATION	46,936,794	3,977,136	4,005,201	4,107,831	4,127,947	3,690,155	3,955,485	3,653,333	3,724,380	3,488,557	3,885,430	4,263,478	4,057,861
HYDRO GENERATION													
West Hydro	4,323,248	343,170	515,936	571,027	463,081	556,990	549,496	445,498	189,768	148,284	141,831	179,372	218,795
East Hydro	458,853	25,009	27,947	29,611	26,275	20,180	41,674	33,747	52,856	56,945	59,318	57,682	27,610
TOTAL HYDRO	4,782,101	368,179	543,883	600,638	489,356	577,170	591,169	479,245	242,623	205,229	201,149	237,054	246,405
TOTAL RESOURCES	85,094,894	5,984,797	6,525,890	6,940,767	6,732,815	6,082,379	7,104,234	8,295,774	9,088,817	7,699,380	7,172,836	7,132,288	6,334,917

GRID Study Results
Resource Statistics
"THE RACK"

	10/01-09/02	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
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FUEL BURNED (Tons, MMBtu)													
Blundell	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	622,484	33,208	54,198	54,674	54,107	44,182	51,223	54,716	56,247	53,159	55,863	56,365	54,541
Cholla	1,357,373	113,252	119,422	116,229	112,061	107,813	85,210	112,203	120,524	105,455	115,070	124,854	125,279
Colstrip	709,964	44,132	38,494	64,109	64,255	57,978	64,120	62,050	63,751	61,949	63,075	64,185	61,866
Craig	599,246	53,616	49,548	50,265	49,614	44,616	51,347	37,754	55,942	45,783	51,629	56,595	52,537
Dave Johnston	3,877,432	341,367	330,302	340,470	341,412	307,681	340,392	330,050	329,568	225,462	321,253	340,921	328,552
Gadsby	3,426,327	178,648	94,334	71,364	39,856	-	65,577	259,517	264,304	470,821	707,723	850,946	423,237
Gadsby CTs	542,599	-	-	-	-	-	-	-	-	-	-	-	542,599
Hayden	241,091	22,588	20,059	20,216	20,094	16,259	10,588	20,084	21,872	19,710	23,005	24,525	22,091
Hermiston	11,054,600	1,196,178	1,217,153	1,226,049	1,186,464	992,040	1,151,882	840,290	906,150	48,677	42,206	1,147,811	1,099,700
Hunter	3,821,694	333,381	330,096	339,075	340,191	304,510	336,553	219,004	310,307	327,796	339,823	339,509	301,450
Huntington	3,064,773	218,300	262,124	268,899	269,378	237,007	266,723	262,579	218,721	257,954	270,538	271,213	261,336
Jim Bridger	5,944,747	533,475	516,335	522,333	539,997	483,158	524,551	495,782	397,754	411,760	469,792	537,300	512,509
Little Mountain	1,669,069	159,504	163,290	177,938	177,940	160,719	168,732	163,290	159,504	141,178	17,975	33,157	145,844
Naughton	2,719,445	239,746	216,844	222,235	226,650	207,566	187,748	238,586	244,897	216,468	235,106	248,747	234,849
West Valley CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	1,621,876	147,313	142,535	146,953	147,357	132,935	146,983	90,056	135,490	130,764	135,463	135,330	130,700
BURN RATE (Tons/MWH, MMBtu/MWH)													
Blundell	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	0.474	0.472	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474
Cholla	0.557	0.561	0.554	0.558	0.561	0.556	0.553	0.559	0.556	0.563	0.559	0.554	0.552
Colstrip	0.665	0.665	0.664	0.665	0.664	0.664	0.664	0.665	0.665	0.665	0.666	0.664	0.665
Craig	0.498	0.498	0.498	0.498	0.498	0.498	0.498	0.497	0.497	0.499	0.498	0.497	0.497
Dave Johnston	0.678	0.678	0.678	0.678	0.678	0.678	0.678	0.678	0.677	0.679	0.678	0.678	0.678
Gadsby	14.344	15.528	15.203	15.200	15.691	-	14.736	15.860	15.841	14.362	13.576	13.544	14.755
Gadsby CTs	10.783	-	-	-	-	-	-	-	-	-	-	-	10.783
Hayden	0.505	0.504	0.505	0.505	0.505	0.505	0.504	0.504	0.504	0.505	0.504	0.504	0.504
Hermiston	7.932	7.602	7.656	7.999	8.492	8.545	7.759	7.786	7.734	47.701	275.854	7.640	7.671
Hunter	0.460	0.459	0.460	0.460	0.460	0.460	0.460	0.461	0.460	0.460	0.460	0.460	0.459
Huntington	0.449	0.451	0.449	0.449	0.449	0.449	0.449	0.449	0.448	0.450	0.449	0.449	0.449
Jim Bridger	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.563	0.567	0.566	0.563	0.563
Little Mountain	15.889	16.000	15.797	15.618	15.618	15.618	15.797	15.797	16.000	16.303	16.652	16.670	16.303
Naughton	0.556	0.555	0.557	0.557	0.556	0.556	0.557	0.554	0.554	0.557	0.556	0.554	0.555
West Valley CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	0.743	0.741	0.741	0.741	0.741	0.741	0.741	0.741	0.746	0.747	0.746	0.747	0.747
AVERAGE FUEL COST ($/Ton, $/MMBtu)													
Blundell	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593	22.593
Carbon	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344	17.344
Cholla	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354	23.354
Colstrip	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153	10.153
Craig	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010	19.010
Dave Johnston	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270	11.270
Gadsby	4.279	5.138	4.882	4.893	5.062	5.062	5.062	4.047	4.047	3.378	3.203	3.105	3.470
Gadsby CTs	3.240												3.240
Hayden	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179	22.179
Hermiston	2.617	2.493	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628
Hunter	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703	17.703
Huntington	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829	18.829
Jim Bridger	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784	16.784
Little Mountain	4.049	4.908	4.652	4.663	4.832	4.832	4.832	3.817	3.817	3.148	2.973	2.875	3.240
Naughton	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831	19.831
West Valley CT	#DIV/0!												
Wyodak	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411	9.411

ICNU/112
Falkenberg/44

PEAK CAPACITY (NAMEPLATE)													
Blundell	23	23	23	23	23	23	23	23	23	23	23	23	23
Carbon	175	175	175	175	175	175	175	175	175	175	175	175	175
Cholla	380	380	380	380	380	380	380	380	380	380	380	380	380
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148	148
Craig	165	165	165	165	165	165	165	165	165	165	165	165	165
Dave Johnston	772	772	772	772	772	772	772	772	772	772	772	772	772
Gadsby	235	235	235	235	235	235	235	235	235	235	235	235	235
Gadsby CTs	117	-	-	-	-	-	-	-	-	-	-	-	117
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78
Hermiston	245	236	243	245	241	239	238	235	234	231	230	231	233
Hunter	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,117	1,117	1,122
Huntington	895	895	895	895	895	895	895	895	895	895	895	895	895
Jim Bridger	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413
Little Mountain	16	14	15	16	16	16	15	15	14	13	12	12	13
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700
West Valley CT	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyodak	276	276	276	276	276	276	276	276	252	252	252	252	252
CAPACITY FACTOR													
Blundell	82.71	85.22	85.09	83.48	85.44	84.57	83.63	84.94	85.37	83.37	85.22	84.50	61.29
Carbon	85.72	54.01	90.81	88.64	87.70	79.20	83.07	91.67	91.20	89.02	90.58	91.39	91.36
Cholla	73.18	71.43	78.73	73.64	70.63	75.88	54.50	73.38	76.67	68.41	72.76	79.72	82.98
Colstrip	82.39	60.28	54.39	87.62	87.83	87.74	87.63	87.63	87.06	87.47	86.03	87.73	87.35
Craig	83.30	87.77	83.77	82.22	81.15	80.79	84.02	63.92	91.64	77.31	84.48	92.72	88.89
Dave Johnston	84.61	87.72	87.70	87.48	87.73	87.53	87.46	87.63	84.73	59.75	82.51	87.60	87.22
Gadsby	11.60	6.58	3.67	2.69	1.45	0.00	2.55	9.67	9.54	19.37	29.82	35.94	16.95
Gadsby CTs	59.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.73
Hayden	69.94	77.18	70.77	68.99	68.56	61.40	36.17	70.94	74.72	69.54	78.62	83.84	78.00
Hermiston	67.33	89.62	90.87	84.09	77.93	72.28	83.84	63.78	67.30	0.61	0.09	87.41	85.45
Hunter	84.61	86.92	88.90	88.33	88.64	87.77	87.67	58.75	80.78	88.22	88.93	88.85	81.25
Huntington	87.01	72.76	90.56	89.89	90.06	87.70	89.17	90.72	73.35	89.04	90.44	90.68	90.28
Jim Bridger	85.23	90.15	90.17	88.21	91.28	90.40	88.59	86.56	67.14	71.43	78.93	90.81	89.47
Little Mountain	84.22	95.71	95.71	95.71	95.71	95.71	95.71	95.71	95.71	92.52	12.09	22.28	95.58
Naughton	79.82	82.94	77.26	76.61	78.24	79.40	64.69	85.43	84.84	77.06	81.23	86.23	84.00
West Valley CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wyodak	93.65	96.79	96.77	96.54	96.82	96.69	96.56	61.13	96.81	96.52	96.79	96.68	96.48

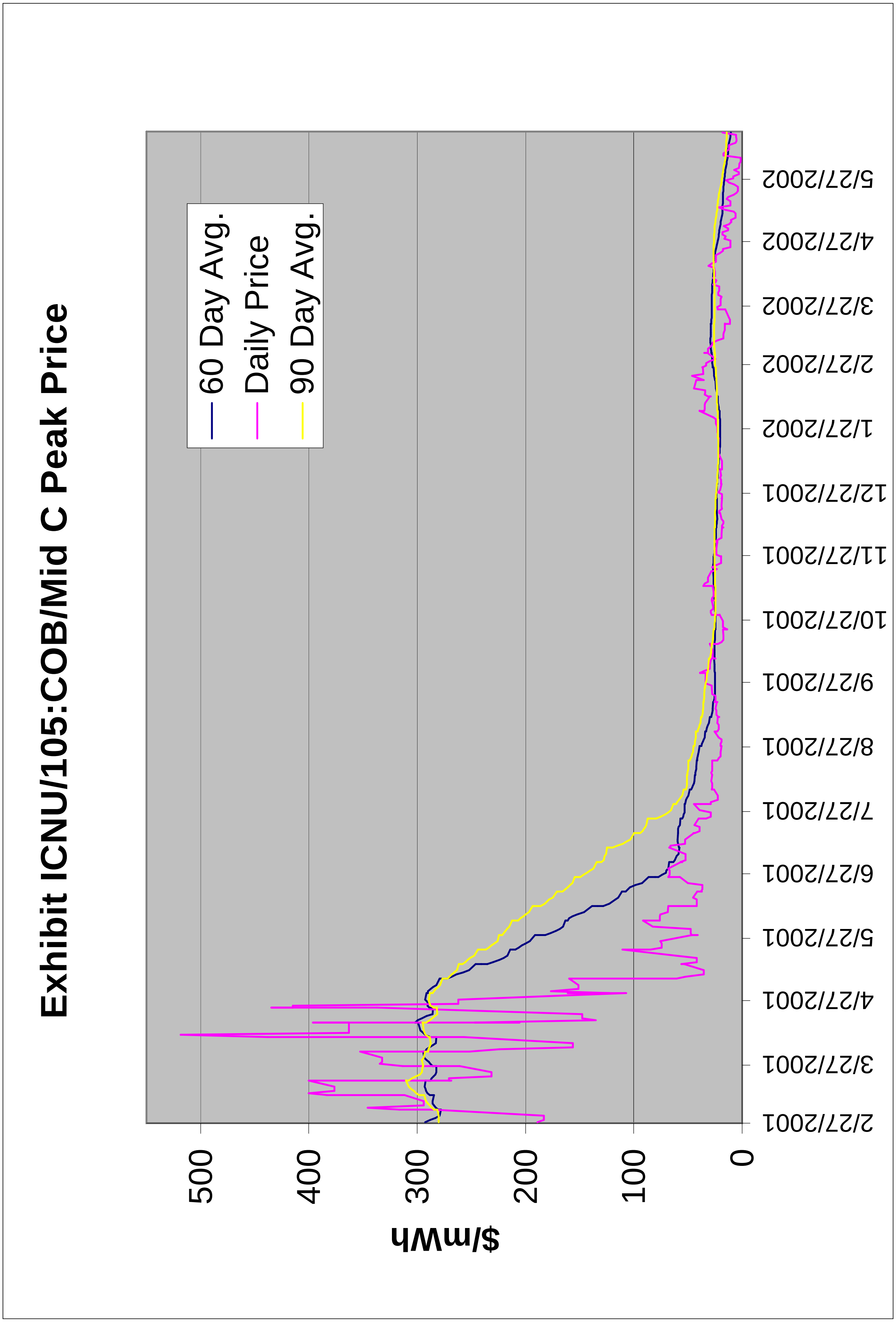
Exhibit ICNU/105:COB/Mid C Peak Price
60 Day Avg.
Daily Price
90 Day Avg.
$/mWh
0
100
200
300
400
500
2/27/2001
3/27/2001
4/27/2001
5/27/2001
6/27/2001
7/27/2001
8/27/2001
9/27/2001
10/27/2001
11/27/2001
12/27/2001
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4/27/2002
5/27/2002

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

SURREBUTTAL TESTIMONY OF

JAMES SELECKY

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

JUNE 27, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James T. Selecky, 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. ARE YOU THE SAME JAMES SELECKY WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. This surrebuttal testimony is responsive to the rebuttal testimony of PacifiCorp witnesses Larry O. Martin and Bernard L. Uffelman, who respond to several witnesses with respect to the calculation of income taxes for ratemaking purposes. I will also respond to the testimony of Daniel J. Rosborough regarding PacifiCorp's pension-related expense and medical benefits. In addition, my surrebuttal testimony briefly responds to Al Kopec's testimony regarding pension expenses and Doug Larsen's testimony regarding Regional Transmission Organization ("RTO") costs.

<u>Consolidated Tax Adjustment</u>

Q. PLEASE SUMMARIZE MR. MARTIN'S TESTIMONY CONCERNING YOUR PROPOSED CONSOLIDATED TAX ADJUSTMENT TO PACIFICORP'S TEST YEAR INCOME TAX EXPENSE.

A. He argues that my proposed income tax adjustment should be rejected because it is inconsistent with the Oregon Commission statutory mandate that rates must be based on cost of service and that Oregon utilities must calculate and report income taxes on a stand-alone basis for regulatory and ratemaking purposes. He also contends that this tax adjustment will create tax timing differences.

Q. IS MR. MARTIN CORRECT THAT YOUR PROPOSED ADJUSTMENT IS INCONSISTENT WITH PACIFICORP'S COST OF SERVICE?

A. No. Indeed, my adjustment is necessary in order to ensure that PacifiCorp's rates reflect only its cost of providing service. Specifically, as a result of ScottishPower's corporate structure, PacifiCorp's income tax expense is reduced. Hence, my adjustment is necessary in order to ensure customers' rates are not increased to provide recovery of an expense that PacifiCorp will not eventually pay to the taxing authorities.

Q. WOULD PACIFICORP HOLDINGS, INC. ("PHI") RECEIVE EXCESSIVE COMPENSATION FOR ITS INVESTMENT IN PACIFICORP IF PACIFICORP'S INCOME TAX EXPENSE IS NOT ADJUSTED TO MORE ACCURATELY REFLECT ACTUAL PAYMENTS TO TAXING AUTHORITIES?

A. Yes. PHI receives a return on its investment from, among other things, income tax contributions from PacifiCorp. However, when PacifiCorp makes payments to PHI based on PacifiCorp's tax liability as a stand-alone utility, PHI does not pay those amounts to taxing authorities when it files its taxes on a consolidated basis. Hence, PHI receives returns far in excess of what a typical investor would normally receive from dividends and stock price appreciation. Accordingly, permitting PHI to retain income tax expense that is not ultimately paid to taxing authorities provides PHI an excessive return on its investment in PacifiCorp.

Q. WHAT OTHER ARGUMENTS DOES MR. MARTIN MAKE IN RESPONSE TO YOUR INCOME TAX EXPENSE ADJUSTMENT?

A. At PPL/1300, Martin/13-14, Mr. Martin argues that it would be inappropriate to use tax benefits associated with deductions of the affiliate to reduce PacifiCorp's tax calculation for regulatory purposes. He argues that ScottishPower bears the expense of its investment and that the underlying interest expense is not borne by ratepayers. Finally, he argues that PacifiCorp witness Williams demonstrated that PacifiCorp's affiliation with ScottishPower has benefited PacifiCorp's ratepayers. Hence, he concludes that this adjustment fails the "benefit-burden" test.

Q. PLEASE RESPOND.

A. Mr. Martin's arguments are simply off base. The issue here is whether PacifiCorp will actually incur income tax expense and should therefore recover that expense from customers. Indeed, as Standard & Poor's ("S&P") notes, PHI is a non-operating, wholly owned subsidiary of ScottishPower. After ScottishPower acquired PacifiCorp in 1999, it established PHI as the United States non-operating subsidiary in December 2001. ScottishPower then financed PHI to own PacifiCorp and three other non-regulated subsidiaries. Hence, PHI was formed and financed, in part, in order to minimize the income tax expense that ScottishPower would have to pay on PacifiCorp's taxable income. Importantly, the issue here is not whether customers should benefit from PHI's interest obligations, but rather the amount PacifiCorp will pay in income tax to federal, state and local governments. If ScottishPower has created a financing structure that will reduce or eliminate PacifiCorp's income tax expense, then PacifiCorp's rates should be adjusted to include only legitimate and known costs of providing service. Hence, my adjustment is purely based on cost of service principles.

Q. AT PPL/1300, MARTIN/7-8, MR. MARTIN ADDRESSES THE CONCEPT OF DEFERRED TAXES AS IT RELATES TO THE COMPANY'S PARTICIPATION IN A CONSOLIDATED RETURN. DOES THE INTEREST DEDUCTION ASSOCIATED WITH THE LOAN USED FOR ACQUISITION PURPOSES GIVE RISE TO DEFERRED TAXES THAT LATER REVERSE?

A. No. The interest deduction that is recognized for ratemaking purposes is permanent and does not give rise to deferred taxes that reverse in the future. The adjustment does not reflect a tax timing difference. This is no different from how other interest expense is treated for calculating ratemaking income taxes.

Q. DOES YOUR ADJUSTMENT INVOLVE THE USE OF OPERATING LOSSES OF OTHER OPERATING COMPANIES OR OTHER SPECIAL DEPRECIATION OR DEPLETION DEDUCTIONS IN ORDER TO REDUCE PACIFICORP'S INCOME TAXES FOR REGULATORY PURPOSES?

A. No. The only difference between the approach that I have supported and the method that PacifiCorp put forth is the recognition of the manner in which PacifiCorp was acquired, the utilization for ratemaking purposes, and the tax benefit of the interest deduction associated with the internal loan used for this purpose. By not recognizing this interest deduction, PacifiCorp is essentially collecting from its Oregon ratepayers income taxes that will never be paid.

Q. AT PPL/1300, MARTIN/5-6, MR. MARTIN INDICATES THAT FILING A CONSOLIDATED TAX RETURN DOES NOT CREATE A PERMANENT BENEFIT. PLEASE RESPOND.

A I do not believe this is an accurate statement in the context of my proposal. My proposal is not based on timing differences or losses carried forward, or any type of special deductions; and it does not create a net operating loss or deferred taxes that reverse in the future. My tax adjustment recognizes the manner in which ScottishPower chose to structure its acquisition of PacifiCorp.

Q. DOES THE INTEREST DEDUCTION ASSOCIATED WITH THE LOAN USED FOR ACQUIRING PACIFICORP GIVE RISE TO DEFERRED TAXES THAT LATER REVERSE?

A. No. The interest deduction is permanent and does not give rise to deferred taxes that reverse in the future.

Q. AT PPL/1300, MARTIN/8, LINES 21-22, MR. MARTIN STATES THAT PACIFICORP'S TAXABLE INCOME IS COMPUTED AND REPORTED TO THE IRS ON A SEPARATE COMPANY BASIS. IS THIS CORRECT? IF SO, WHAT DIFFERENCE DOES IT MAKE?

A. It may be true that with a consolidated tax return of PHI, there is a separate calculation for PacifiCorp. However, the taxes that are paid by PHI are determined from the consolidated filing, which blends the operating results and financing of each individual entity of the consolidated group. PacifiCorp does not pay to the federal or state governmental entity any amounts for income taxes. Thus, while Mr. Martin's statement may be accurate, it tells us nothing about the appropriateness of any particular approach to determining income taxes for regulatory purposes.

Q. AT PPL/1300, MARTIN/13-14, MR. MARTIN SEEMS TO BE INDICATING THAT THE RATEPAYERS SEE ALL THE BENEFITS WHILE THE SHAREHOLDERS OR AFFILIATES ABSORB ALL THE COST. DO YOU BELIEVE THAT IS A FAIR APPRAISAL OF YOUR PROPOSAL IN THIS CASE?

A. No. My adjustment is strictly based on the interest associated with the internal loan created in order to produce a tax benefit in association with the acquisition of PacifiCorp by ScottishPower. It is the earnings from PacifiCorp that allow PHI to file a tax return that substantially reduces its state and federal tax obligation. If the taxes that PacifiCorp includes in its revenue requirement are not paid to the taxing authority, those taxes should not be included in customer rates.

Q. HAVE YOU REVIEWED THE TESTIMONY OF PACIFICORP WITNESS BERNARD L. UFFELMAN?

A. Yes. Mr. Uffelman provides the results of a survey of the regulatory treatment of income tax expense by various commissions throughout the United States and provides comments on the treatment of income taxes proposed by various parties.

Q. PLEASE COMMENT ON MR. UFFELMAN'S TESTIMONY.

A. First, the situation that exists with PacifiCorp and PHI is unique. That is, PacifiCorp has included in its cost of service a provision for state and federal income taxes that exceeds the amount that will actually be paid. Therefore, the results of the survey are not surprising since I am not aware of another utility that is structured like PacifiCorp and PHI.

Second, regarding Mr. Uffelman's comments on sound regulatory policies, I have addressed this earlier in my testimony.

Pension Expense and Benefits

Q. HAS PACIFICORP ADJUSTED ITS TEST YEAR PENSION EXPENSE?

A. Yes. Mr. Rosborough reports that PacifiCorp's actual FAS87 pension expense for 2005 is $48.4 million (subject to a final true-up that will occur before the end of June). Therefore, PacifiCorp has increased its 2006 FAS87 pension expense in this case from $42.4 million to $48.4 million. Also, PacifiCorp reports that its actual FAS106 expense for 2005 is $24.1 million. This is also subject to a final true-up that will occur before the end of June. The use of the 2005 actual expense reduces PacifiCorp's 2006 expense projections from $26.8 million in its original filings to $24.1 million.

Q. SHOULD THE COMMISSION ADOPT PACIFICORP'S REVISED ESTIMATES OF ITS FAS87 AND FAS106 PENSION COSTS?

A. No. A combination of these two items increases PacifiCorp's test year pension expense by approximately $2 million. It is inappropriate for the Company to selectively revise its cost estimates for certain items at this late stage of the rate proceeding. The Commission should not include cost increases that the Company could have identified in its cost of service. Just as there are items that will increase costs, there can be offsetting items that will decrease PacifiCorp's cost. Therefore, the Commission should not reflect PacifiCorp's revised pension expense in its total cost of service. In addition, there are assumptions that can affect the determination of pension expense.

Q. DO YOU HAVE ANY ISSUES REGARDING ANY OF THE ASSUMPTIONS PACIFICORP UTILIZED TO DETERMINE ITS PENSION COSTS?

A. Yes. First, as I indicated in my direct testimony, I take exception with the utilization of a 5.75% discount rate. The Commission should utilize a 6.75% discount rate for purposes of calculating PacifiCorp's pension expense.

Q. WHY DO YOU SUPPORT THE UTILIZATION OF A 6.75% DISCOUNT RATE TO DETERMINE PACIFICORP'S PENSION EXPENSE?

A. As I indicated in my direct testimony, the Company's cost of equity witness, Mr. Hadaway, indicated that bond interest rates will increase over the next year. It is my understanding that he continues to support this in his rebuttal testimony. If interest rates are to increase over the next year, so will the discount rate utilized to calculate the appropriate pension expense. Increasing the discount rate would lower the pension expense.

Q. DO YOU HAVE ANY OTHER COMMENTS TO MAKE REGARDING THE DEVELOPMENT OF PACIFICORP'S PENSION EXPENSE?

A. Yes. In developing its pension expense, PacifiCorp utilized a 4.0% rate of increase in compensation levels over the period that the pension expense was determined. Looking at the EIA Annual Energy Outlook 2005, over the next 20 years the projected inflation rate as measured by the CPI is approximately 2.6%. Utilizing a lower rate of escalation would result in lower pension expense.

Q. WHAT IS YOUR RECOMMENDATION IN THIS PROCEEDING REGARDING THE APPROPRIATE LEVEL OF PENSION EXPENSE?

A. I continue to support the level of pension expense as stated in my direct testimony. As indicated in the testimony of Staff witness Michael Dougherty, pension expense is a volatile number that can change from year to year. Also, as I have indicated in both my direct testimony and my surrebuttal testimony, there are any number of assumptions, such as discount rate, expected return, and rate of increase in compensation levels that can affect the amount of pension expense.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE REBUTTAL TESTIMONY OF AL KOPEC AS IT RELATES TO THE DETERMINATION OF PENSION EXPENSE?

A. Yes. Mr. Kopec states that PacifiCorp's actual pension expense for 2006 is more likely to mirror actual 2005 expense level than 2004 expense level. However, as I indicated above, the determination of the 2005 pension expense is dependent upon certain key assumptions. Those assumptions include the development of the appropriate discount rate and the rate of increase in compensation levels. Since adjusting these parameters will affect the level of pension expense, I continue to support the level of pension expense included in my direct testimony.

Q. DO YOU HAVE ANY COMMENTS TO MAKE REGARDING MR. ROSBOROUGH'S CRITICISM OF YOUR PROPOSED ADJUSTMENTS TO MEDICAL, DENTAL AND VISION BENEFIT COVERAGE COSTS?

A. Yes. PacifiCorp continues to support the utilization of an increase in medical costs of 12%. As indicated in my direct testimony, this is inconsistent with industry trends and PacifiCorp's historical level of cost increases for medical benefit costs. Mr. Rosborough contends that over the past 18 months, PacifiCorp's medical expenses have increased about 12%. It is unclear whether this is an annual amount or if it covers the entire 18-month period. However, as indicated in my direct testimony, PacifiCorp's medical costs have escalated from 2000 to 2004 at rates below the national average. As a result, I believe it is appropriate to utilize the average expected annual increase of 8% for medical expenses as reported in the 2005 Towers Perrin Health Care Cost Survey that is referenced in my direct testimony.

<u>RTO Expense</u>

Q. PACIFICORP WITNESS DOUG LARSON TAKES EXCEPTION WITH YOUR EXCLUSION OF RTO DEVELOPMENT COST. HOW DO YOU RESPOND?

A. Mr. Larson has not quantified any benefits associated with the RTO included in PacifiCorp's revenue requirement. Therefore, I continue to recommend these costs be deferred and reviewed once the RTO is operating and providing benefits to PacifiCorp's Oregon ratepayers.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

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	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

SURREBUTTAL TESTIMONY OF

KATHRYN E. IVERSON

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

JUNE 27, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kathryn E. Iverson, 17244 W. Cordova Court, Surprise, Arizona 85387.

Q. ARE YOU THE SAME KATHRYN E. IVERSON WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I will comment on two issues. First, my surrebuttal discusses PacifiCorp witness David Taylor's response to my recommendation for a functional reconciliation that includes recognition of generation demand and energy and transmission demand and energy. The second area of this testimony responds to PacifiCorp witness William Griffith's recommendation for time of day energy pricing for Schedule 48 customers served on cost-based supply service.

Q. MR. TAYLOR ARGUES THAT THE REVISED PROTOCOL IS FOR ALLOCATION OF COSTS AMONG STATES AND THAT STATE COMMISSIONS HAVE FULL INDEPENDENT AUTHORITY AS TO THE ALLOCATION OF COSTS AMONG CUSTOMER CLASSES. HOW DO YOU RESPOND?

A. While it is certainly true that the Revised Protocol is used for the allocation of costs among states, it also provides the basis for the functionalization of the Oregon revenue requirement in the reconciliation process. That is, the results of the Revised Protocol study are used by PacifiCorp to reconcile marginal costs to the functional revenue requirements. Consequently, the "two processes" that Mr. Taylor alludes to (allocation of costs among states and allocation of costs among customer classes) are certainly not independent of each other in Oregon, but are linked in the reconciliation process. My proposal simply refines PacifiCorp's reconciliation process by using additional information from the Revised Protocol. My recommendation in no way detracts from the

Oregon Commission's deliberative process—it merely gives the Commission additional relevant information.

Q. AT PPL/412, TAYLOR/10, MR. TAYLOR CLAIMS THAT YOUR RECONCILIATION PROPOSAL "SIMPLY SHIFTS COSTS BETWEEN THE DEMAND AND ENERGY COMPONENTS OF CUSTOMER PRICES." DO YOU AGREE?

A. No. My reconciliation proposal is concerned with the overall revenue requirement that will be recovered from customer classes. PacifiCorp's current structure of customer prices as between demand and energy would still be retained under my proposal. For example, the current pricing structure for cost-based supply (Schedule 200) for Schedule 48 customers is entirely energy-based, with no demand component. This energy-only pricing structure would be retained under my reconciliation proposal. Transmission-related costs are currently recovered through demand charges. This demand-only pricing structure would also be retained. Under my reconciliation proposal, there is no shift between demand and energy components of customer prices.

Q. MR. TAYLOR OBSERVES THAT, ACCORDING TO THE COMMISSION'S CURRENT POLICY, AS INCREMENTAL ENERGY COSTS BECOME A LARGER PORTION OF TOTAL GENERATION MARGINAL COSTS, ENERGY USAGE PLAYS A LARGER ROLE IN APPORTIONING THE REVENUE REQUIREMENT AMONG CUSTOMER CLASSES. PPL/412, TAYLOR/10. PLEASE COMMENT.

A. Mr. Taylor is correct in his observation regarding incremental energy costs and the apportionment of the revenue requirement among customer classes. However, the problem implicit in this policy is that the "energy usage" to which he alludes to as playing the "larger role" in the apportioning of the revenue requirement is "energy usage" in its most generic, uncomplicated form—that is, annual energy consumed at all times of the day, month and year. Under this policy, no consideration is given for "energy usage" during low-cost, off-peak times versus "energy usage" during high-cost, on-peak times.

Taken to its extreme, as incremental energy costs approach 100% of total generation marginal costs, annual "energy usage" would exclusively determine the allocation of revenue requirement under the present policy. This would effectively allocate 100% of any increase in generation revenue requirements on the basis of "energy usage," and would altogether eliminate the influence of the timing of when energy is used. Customers with energy usage during low-cost periods would be allocated revenue requirement increases no differently than customers with equivalent energy usage during high-cost periods. That would be an unfortunate price signal that can only lead to higher prices for all customers in the future.

Q. HOW DOES YOUR RECONCILIATION PROPOSAL HELP TO RECTIFY THIS INHERENT PROBLEM?

A. The generation energy and transmission energy functional revenue requirements resulting from the Revised Protocol reflect the amount of revenues that must be collected from Oregon customers in order to serve their "energy usage" over all hours of the year. Consequently, when these functions are used to reconcile the marginal generation and transmission energy costs, there is a better alignment of costs to these non-time-differentiated marginal costs.

Q. MR. GRIFFITH CLAIMS THAT EVEN THOUGH LARGE POWER USERS WILL PAY MORE FOR ON-PEAK POWER UNDER PACIFICORP'S TIME OF DAY PRICING PROPOSAL, THEY WILL PAY LESS FOR OFF-PEAK POWER. PPL/1204, GRIFFITH/9-10. IS THIS REASON ENOUGH FOR THE COMMISSION TO APPROVE PACIFICORP'S TIME OF DAY ENERGY PRICING FOR SCHEDULE 48 CUSTOMERS SERVED ON COST-BASED SUPPLY SERVICE?

A. No. PacifiCorp's proposal is not based on any cost allocation principle or hourly difference in energy costs. In fact, as Mr. Taylor admits, their marginal cost study is not designed to capture the hourly or seasonal differences in energy costs. Mr. Griffith does point out, however, that PacifiCorp is making its time of day proposal "in order to commence a gradual movement to time differentiated prices and to provide some opportunity for customers to save money by shifting their loads to off-peak periods." PPL/1204, Griffith/9. While ICNU appreciates PacifiCorp commencing the gradual consideration of time-differentiated energy costs, we believe the appropriate starting point should be in the marginal cost study. Rate design should then flow from the cost study, rather than using an arbitrary energy price differential in hopes of customers shifting load.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.