-BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH-

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules and Electric Service Regulations	**Docket No. 01-035-01** Utah Division of Public Utilities Exhibit No. DPU 8.0

Prefiled Direct Testimony of Rebecca L. Wilson

For The

Division of Public Utilities

Department of Commerce

State of Utah

June 4, 2001

Q. Would you please state your name and business address?

A. Rebecca L. Wilson, 160 East 300 South, Heber M. Wells Building, Salt Lake City, Utah 84145-0807

Q. By whom are you employed?

A. The Division of Public Utilities, Utah Department of Commerce.

Q. What is your position with the Division of Public Utilities and what are your current responsibilities?

A. I am a Technical Consultant responsible for providing in-house expertise regarding regulatory economics and for presenting the views of the Division before the Commission on matters related to utility costs and rate design.

Q. What is your educational and professional background?

A. I received a Bachelors degree in Political Science from the University of Utah in 1979 and a Masters degree in Economics from the University of Utah in 1986. My primary fields of study in graduate school were quantitative methods and applied microeconomics. I have over 20 years of experience as an analyst of energy-related issues, and over ten years of experience as an analyst and expert witness on public utility issues. My resume is provided as Exhibit No. DPU 8.1 .

Q. Have you filed testimony with the Utah Public Service Commission before?

A. Yes. I have filed direct and rebuttal testimony and appeared as a witness in previous cases before the Utah Public Service Commission. A summary of this and other utility-related work experience is also provided in Exhibit No. DPU 8.1 .

Q. What is the purpose of your testimony in this proceeding?

A. I present the Division's recommendations regarding net power costs, retail and wholesale revenue requirement responsibility, and retail special contracts.

Q. In summary, what will you address in this testimony?

A. I identify nine adjustments to net power costs that the Division recommends the Commission adopt in this case. In total, these adjustments result in an annual total company net power cost of $537 million which amounts to an increase of $154 million in net power cost from the previous rate case amount (about $383 million), a decrease of $65 million in net power cost from the test period actual net power cost ($602 million) and a decrease of $276 million from PacifiCorp's requested net power costs ($813 million). On a Utah basis, these adjustments result in an approximate increase of $57 million over the net power cost approved in the last PacifiCorp general rate case, a $102 million reduction compared with PacifiCorp's filed net power cost request (about $300 million), and a $24 million reduction compared with actual net power cost ($222 million). DPU Exhibit No. 8.3 is a list of these adjustments showing incremental and cumulative adjustment to total and Utah net power cost. The Division recognizes that this is a substantial increase in net power cost over what is currently in rates and a substantial reduction in test period actual net power costs. I will present the Division's view that this amount is reasonable and consistent with rate making policy and with fair allocation of cost responsibility between ratepayers and shareholders.

Five of the Division's net power cost adjustments will be described and supported by Division witness Falkenberg, two will be described and supported by Division witness Hayet, one will be described and presented by Division witness Burrup. I propose and provide the analytical support for one of the Division's nine proposed net power cost adjustments.

The adjustment I propose adds revenue to fourteen long term firm wholesale contracts so that average revenue from each contract is equal to PacifiCorp's requested embedded cost. This adjustment reduces PacifiCorp's requested increase in total company net power costs by $67 million. On a Utah basis, using Division recommended allocation factors, this amounts to $25 million.

In support of the Division's net power cost adjustments, I will present and provide support for the Division's recommendation that normalized power costs and revenue credit treatment of system allocated wholesale sales be continued as a rate making policy. This recommendation is conditioned on acceptance of criteria to allocate sharing of risk for this policy between customers and shareholders. We recommend reaffirmation of the criteria ordered by the Commission in Docket No. 90-035-06. We recommend the Commission consider adoption of the language refinement endorsed by the Wholesale Contracts Task Force report of April, 1993 for one of the criteria.

I next discuss revenue required for retail special contracts and provide analytical support for the Division's recommendation that special contracts be dealt with outside of this rate case.

Finally, I recommend removing sales for resale revenues from the Brigham City all requirements contract from Utah revenues and add the revenues to the Utah FERC jurisdiction.

Q. Please describe the scope of your investigation of the reasonableness of PacifiCorp's requested net power costs.

A. I reviewed the prefiled direct testimony of PacifiCorp witnesses, talked with PacifiCorp personnel, reviewed PacifiCorp responses to intervener data requests, reviewed testimony, transcripts and Commission orders regarding the adoption of normalized power costs and adoption of the revenue credit and reviewed PacifiCorp's minutes and capacity expansion plans as provided in their Resource and Market Planning Program (RAMPP). I also worked with consultant's Hayet and Falkenberg hired by the Division and the Committee of Consumer Services to examine PacifiCorp's net power cost model and assumptions.

Q. What exactly is "net power cost"?

A. Literally, net power cost is the sum of all power costs net of revenues from sales. However, the term net power cost in rate case proceedings has come to mean the sum of system allocated costs in several specific FERC accounts less the system allocated revenues in another specific FERC account. All of these accounts are adjusted from actual results in a test period for the purpose of removing non-recurring and abnormal conditions or annualizing known and measurable price or quantity changes within the test year. To this end, PacifiCorp proposed and has used for about the last ten years, a computer program to normalize the costs and revenues in the FERC accounts for the purpose of setting rates. These accounts are: fuel costs 501, 503, 547; wheeling expenses 565; system allocated wholesale purchases 555; and system allocated wholesale sales 447. All other power related accounts, i.e., hydro expenses, wheeling revenues, situs allocated wholesale revenues, are set in rates as they actually occur in a test period or they are adjusted some other way but not through PD Mac or its new successor in this rate case, the Excel spreadsheet model.

Q. Please describe the Division's investigation of PacifiCorp's net power costs.

A. The Division's most recent investigation of net power costs began with the conclusion of the last PacifiCorp general rate case, Docket No. 99-035-10. In that case, the Commission ordered an investigation of alternatives to the PD-Mac Model, PacifiCorp's power cost normalizing tool. Further, the Commission ordered a forum on retail - wholesale revenue requirement responsibility. Both of these issues affect calculation of net power costs for rate setting purposes. The Division began its investigation of net power cost by reviewing the reasons for setting rates based on modeled "normal" power costs coupled with a revenue credit from system allocated wholesale sales. This policy replaced previous reliance on actual demand-related power costs determined in a general rate proceeding, situs allocation of long-term firm wholesale transactions and a balancing account in between rate cases for energy related variable cost and non-firm wholesale revenue change. It is my understanding that only non-firm, short term (less than one year) wholesale transactions were included in the balancing account. Demand-related power purchase costs were not included in the balancing account.[1]

One meeting of each of the work groups ordered by the Commission in Docket No. 99-035-10 was held. It was the conclusion of all parties that since PacifiCorp would file an alternative to its PD-Mac model in this rate case, the work group on examining alternatives to PD Mac would disband and parties would address the issues in the context of the new rate case. It was further agreed that PacifiCorp would hold a technical conference on the replacement PD-Mac model once it was completed. A memo by the participating parties was filed with the Commission stating this conclusion on December 21, 2000. The technical conference on PacifiCorp's replacement model was never held. The Division hired consultant's Hayet and Falkenberg to review PacifiCorp's alternative model and the assumptions PacifiCorp used in this rate proceeding. Their testimony in this proceeding presents the Division's position

[1] Docket No. 90-035-06, cross examination of PacifiCorp witness Greg Duvall, page 301, lines 5-7.

on use of the model for setting rates and recommended modeling changes for the future.

The forum on retail - wholesale revenue requirement also met once and prepared a combined data request. Another meeting of regulators was held to outline criteria or guidelines against which decisions regarding retail and wholesale revenue requirement could be assessed. Following this meeting, PacifiCorp filed its general rate case. Upon filing this general rate case proceeding, PacifiCorp requested that the forum's data request be resubmitted in the context of the formal rate case proceeding. The group has not met again. It is the Division's understanding that parties will present their points of view on the issues raised in the forum in this general rate case proceeding. It was in preparation for the foum meeting that the Division uncovered the history behind adoption of the revenue credit and learned that it was adopted subject to criteria designed to address customer risk mitigation. It is my intent to present the Division's recommendations in this testimony.

Q. When did the Commission terminate use of an energy balancing account for variable energy costs and revenues and a separate jurisdiction for firm wholesale sales and adopt use of "normal" power cost offset by credit from system allocated wholesale revenue?

A. In Docket 90-035-06, PacifiCorp requested termination of the balancing account and proposed the use of normal power costs and a revenue credit. The Commission resolved the issues raised in this case over a period of time. First, on December 7, 1990, the Commission adopted by order the revenue credit policy. Use of normal power costs and elimination of the energy balancing account (EBA) was adopted by Commission order post- December 1992 after suspending the EBA in 1991 and conducting a trial period comparing the two rate making procedures and following technical conferences on the PD Mac normalizing tool.

Q. Why did PacifiCorp request elimination of the balancing account and adoption of a revenue credit for firm wholesale sales and use of normalized power costs?

A. The reasons stated in 1990 by PacifiCorp for eliminating the balancing account and adopting normal power cost and revenue credit was that it improved management incentives for minimizing power costs and promoted stable rates and better matched PacifiCorp's desire to manage its performance in an increasingly competitive wholesale market. In his prefiled direct testimony, PacifiCorp witness Gregory Duvall stated,

> The use of a reasonable estimate of net power costs stabilizes the prices paid by the Company's retail customers and places the risks and responsibility of managing energy costs, over which the customer has no control, on the Company."[2]

On elimination of the balancing account, Mr. Duvall stated in his prefiled direct testimony, page 15, lines 13-20:

> Retail customers would no longer be subject to the risk of changes in future energy costs. By basing energy costs on fixed values, retail customers are guaranteed a certain level of performance from the Company whether the Company performs well or not. The burden and risk are clearly on the Company to manage its costs and revenues. Elimination of the EBA creates the greatest incentive to the Company to plan and operate efficiently.

On the merits of normalized power costs, he states on page 20, lines 2-17.

> The results of the production cost model are not intended to match actual costs on a year by year basis but are intended to provide results which are fair and reasonable and simulate the operation of the system under normal conditions. The fundamental difference between using normalized and actual net power costs is the placement of risks and rewards associated with over running and under running net power costs. Using actual information places the risks and rewards on retail customers, while using normalized information

[2] Docket No. 90-035-06, prefiled direct testimony of Gregory Duvall, page 5, line 26 through to page 6, line5.

> places the risks and rewards on the Company and its shareholders. In deciding the fate of the EBA, the Commission should carefully consider which group it believes should properly bear the risk.

Q. How did the Division respond to PacifiCorp's requested changes?

A. Notwithstanding the Company's commitment to accepting the risk associated with fluctuating power costs and its belief that it was a reasonable and manageable risk for shareholders to undertake, Division witness, Ken Powell cited concern over regulatory oversight and risks to retail customers from adopting a revenue credit for firm wholesale sales. He noted that customers would bear the risk of missed forecasts and noted the concern of giving management discretion over decisions which could ultimately cause rate increases to customers. If management decisions proved faulty, ratepayers could be asked to bear that cost in a general rate proceeding. His concern led him to recommend using both a revenue credit and a FERC jurisdiction and the adoption of criteria to manage customer risk. PacifiCorp and the Committee of Consumer Services agreed with the Division's proposed criteria (Duvall, Rebuttal, page 18, Bartels, Rebuttal, page 2) and the Commission adopted the criteria in its December 7, 1990 order.

Q. What was the criteria that the Commission adopted to mitigate customer risk associated with adoption of the revenue credit policy?

A. In its Phase I order (December 7, 1990, pages 16-17), the Commission stated,

> In rebuttal, the company accepted the Division's modified proposal, which is succinctly described in pages 11-13 of Division witness Powell's supplemental testimony... Having considered the testimony and exhibits on this matter, the Commission finds the Division's proposal described in the testimony above to be just, reasonable and in the public interest and approve such proposal.

Page 12 of Mr. Powell's testimony reads as follows:

1. All existing firm Utah FERC wholesale and wheeling business taking service prior to the merger be excluded from the Utah jurisdiction and included in a FERC jurisdiction for reports and filings in Utah. New firm sales and wheeling at tariffed, fully-embedded rates would also be included in the FERC jurisdiction.

2. Nonfirm sales for resale and wheeling, and long term contracts not covering fully embedded costs where service is begun on or after the merger (Sierra and Puget included), would be treated as revenue credits, after approval of the contracts by the Utah Public Service Commission.

3. In the event that costs are imposed on UP&L by the FERC Order No. 318 that are not fully recovered from those imposing the costs, then those contracts would also be included in the proposed FERC jurisdiction.

4. Any long term contract proposed to be treated as a revenue credit be filed with the Utah Public Service Commission for subsequent approval of that revenue credit status. That filing would have to include the necessary information to verify that:

   A. The sales couldn't have been made at rates based on full embedded costs.
   B. The contract covers marginal cost.
   C. The contract make a contribution to fixed costs.
   D. After a short time, the contract either terminates, or covers full embedded costs.

Q. Was this criteria ever modified?

A. To my knowledge, the Commission has not formally modified this criteria. However, during Phase II of Docket 90-035-06, Mr. Powell proposed to modify standard 4D (Powell, Nov. 1, 1991 COS Testimony, p 19). His modified 4D was,

> 4. D. The contract either terminates, or covers full embedded costs by the time any new production investment is required to provide service to system loads.

To my knowledge, the Commission did not rule on this proposed change but did adopt a stipulation by parties to examine wholesale contract standards in a separate task force. The Commission adopted this stipulation in its January 8, 1992 order. On about April 13, 1993, the Wholesale Contracts Task Force Report was submitted to the Utah Public Service Commission. The report adopted Mr. Powell's criteria with one modification to 4D. The recommended language was,

> 4. D. Pricing shall be structured such that over the life of the contract retail revenue requirement will be protected from increases resulting from resource acquisitions needed to serve the wholesale contract.

Q. Does the Division find this criteria to be reasonable today?

A. Yes. We also think the language refinement offered by the Wholesale Contracts Task Force report adds clarification to the intent and expectations of parties in supporting the revenue credit policy.

Q. To your knowledge, was any long term firm wholesale contract formally submitted to the Utah Public Service Commission for approval as a revenue credit contract?

A. Not that I can determine. However, there is evidence that review of three contracts took place; PacifiCorp prepared a projected cost benefit analysis on the Sierra Pacific II, Puget Sound Power II and Nevada Power contracts, Mr. Powell applied his criteria and he recommended inclusion of the contracts as revenue credits. However, it is unknown that the contracts were formally submitted to the Commission for inclusion as revenue credits, nor have I found a Commission ruling on Mr. Powell's recommendation on the contracts. Other than the review and recommended inclusion of these three contracts, I know of no other formal request by PacifiCorp for Commission approval of contracts for revenue credit treatment.

Q. Is there any discussion in the record of how the standards would be applied over time,

i.e., would the review be a one time review or would it be an ongoing review?

A. Yes. In the transcripts of the proceeding this issue was discussed. Both Division witness Mr. Powell and PacifiCorp witness Mr. Duvall anticipated an up-front review and then ongoing regulatory review of the contracts' performance over time to see that the plan was indeed panning out. Both witnesses anticipated possible allocation of losses that could occur from the revenue credit policy. (Powell, direct, page 243 lines 6-24: Duvall, redirect, page 310, lines 15-25).

Q. Nearly ten years has passed since the revenue credit and normalized power costs were adopted as rate setting policies by this Commission. Given that the primary standard has not been followed, that is, submission of each contract for approval, what is your recommendation regarding inclusion of contracts for revenue credit in this case?

A. I think we have to recognize the intent of the standards adopted by the Commission in 90-035-06. Clearly PacifiCorp and regulators either forgot or neglected to apply the criteria in the past. Effectively, the Division has applied an ongoing type of review standard. This ongoing review resulted in a recommended adjustment to long-term revenues in the last general rate case which the Commission adopted for that Docket. Certainly, if I'd been aware of the 90-035-06 criteria in the last general rate case, I would not have recommended a new standard for reviewing the adequacy of long-term firm revenues included in net power cost determination. However, now that I am aware of the Commission's intent in adopting the revenue credit, I think it should be applied going forward. I believe it is superior to the recommendation I made in the last case in that regulators have greater oversight capability and it has the added virtue of having been agreed to by all parties before the revenue credit policy was put in place. Therefore, I propose an adjustment to long-term firm wholesale revenues that I think is consistent with the standards set out in 90-035-06 and with the subsequent consensus language noted in the Wholesale Contract Task Force Report. Further, I recommend that the Commission reaffirm its 90-035-06 policy with either the original language or the consensus language crafted in the Wholesale Contract Task Force Report.

Q. Does this mean that the Division supports continued use of "normal" variable power costs net of normal wholesale revenues?

A. Yes. The cost minimizing incentives identified by PacifiCorp witnesses in 1990 continue to be important today. Rate stability continues to be important and management must have the ability to make decisions swiftly in today's market. PacifiCorp reaffirmed its benefits recently. In Docket No. 99-035-10, PacifiCorp witness, Mr. Widmer stated on page 2 of his direct testimony:

> The use of normalized net power costs stabilizes the prices paid by the Company's retail customers and places the risks and responsibility of managing energy costs, over which the customer has no control, on the Company.

Mr. Widmer further stated on page 10 of his direct testimony,

> The fundamental difference between using normalized and actual net power costs is the placement of risks and rewards associated with over running and under running net power costs. Using actual information places the risks and rewards on customers, while using normalized information places the risks and rewards on the company and its shareholders.

In its May 24, 2000 order in that case, the Commission stated:

> An EBA is an inappropriate means of sharing risk when half of all the Company's sales are in the wholesale market. An EBA simply puts all risk of the Company's performance in the wholesale market on firm retail ratepayers. Some form of establishing the appropriate degree of risk to be borne by firm retail ratepayers remains.

Q. What is the Division's recommendation regarding allocation of the risk of cost increases associated with adoption of the revenue credit policy?

A. The Division's analysis and recommendation is based on identifying the cost sharing that should occur as dictated by the risk accepted by PacifiCorp. Management elected to use short term power purchases to meet a substantial portion of its wholesale load obligations in the test period. Further, management calculated that it would not have an obligation to meet some of its regulated retail load and therefore reduced its loads from least-cost planning requirements. These decisions left PacifiCorp in a vulnerable position when it was resource short in the summer and the cost of power purchases were significantly higher than the cost of its own generating resources. Whether wholesale price jumped because western resource supply and demand conditions tightened earlier than PacifiCorp had anticipated, or because PacifiCorp had underestimated that prices could be affected by market power abuse or a combination of these events, the effect is the same. The decision to be resource short cost PacifiCorp the substantial increase - some $200 million dollars higher than normal - in actual net power cost noted in this test period. Shareholders have been bearing the cost of these decisions since last summer. It is in the case before us that it must be decided what level of the cost for PacifiCorp's strategy of meeting load obligations will be borne by customers going forward.

Q. You said that management elected to meet long term wholesale load obligations with short term purchases. What evidence do you have to support this statement?

A. The evidence is the decision PacifiCorp made to change the modeling logic in PacifiCorp's RAMPP-5. Prior to RAMPP-5, PacifiCorp's planning process added system capacity subject to the constraint of meeting both long-term wholesale and retail loads at least cost. In RAMPP-5, PacifiCorp effectively removed long term wholesale load obligations from capacity expansion consideration. PacifiCorp summarized this change in the introduction, pages 2-3, of its long-term planning document, the RAMPP-5 December 1997 report, as follows:

> ...wholesale sales and purchases of more than one year are part of the load and resource mix. Because of this, temporary imbalances in wholesale sales versus purchases can have a dramatic impact on planning. For example, two years ago the company signed a long-term peaking contract for winter capacity with Southern California Edison. This met winter peaking needs but did not address summer peaking needs. As a result, the company's peaking needs *(retail plus wholesale)* switched from winter to summer. If instead the company had signed a long-term peaking contract for summer capacity, the company's peaking needs *(retail plus wholesale)* would have remained in the winter.
>
> Therefore, the company is making an adjustment in the RAMPP-5 base case. This adjustment will remove the impact of these temporary imbalances on planning, and it will more closely reflect the company's strategy of relying increasingly on the wholesale market to acquire the resources needed to meet the commitments made in long-term wholesale sales contracts. **The adjustment increases the amount of short-term wholesale purchases made in each of the first five years of the planning horizon to achieve a balance between wholesale sales and wholesale purchases by the fifth year.** This adjustment has the effect of removing the impact of wholesale transactions on IRP modeling.
>
> PacifiCorp believes it has the ability to handle that volume of purchases on its system, and believes there will be sufficient availability of market resources during this time period. The company is currently managing about 5,600 MW in purchases. To achieve the wholesale balancing would require at most an additional 1,800 MW. That would be only about 30 percent of what the company is currently purchasing. The company's transmission, scheduling personnel, and control area personnel are sufficient for that additional volume of activity.
>
> The region is showing approximately a 1.9 percent annual load growth over the next ten years, according to the Western System Coordinating Council (WSCC). The region's reserve margin will not get as low as 15 percent until around 2004-2006. The perception in the region is that there is still a fairly

> large reserve margin available in the marketplace to support purchases throughout the WSCC. This does not include planning additions. The company believes the timing of those additions will be driven by when the market is ready for the added resource. There are numerous developers who are only waiting for market prices to show some indication that they can support additional resources. (italics added for clarification, bold type for emphasis).

In RAMPP-5 meeting minutes, Mr. Powell of the Division noted that WSCC projections of load growth were substantially lower than actual load growth and questioned whether the supply would really be there. PacifiCorp's response was, "If that happens, then market prices will start to sustain the developers' ability to build new plants sooner. There will be a bunch out there trying to build their plants. That will provide a wealth of power in the market place to support purchases." (RAMPP-5 meeting minutes for August 15, 1997, page 2). Mr. Powell replied, "But what that says is that you'd better not sign long-term sales contracts based on current prices." PacifiCorp responded, "Nobody really is." In fact, five of PacifiCorp's underperforming long-term firm contracts in this case were signed after this meeting.[3] In a data request, I asked PacifiCorp to provide their analysis of western system supply and demand. They answered that they had done none, that they only analyze their own load and resource balance. Exhibit No. DPU 8.5 provides copies of these data responses.

It is clear from the RAMPP-5 summary that PacifiCorp anticipated its own substantial summer shortages but that it expected them to be temporary because the wholesale load obligations would decline restoring a balance of total resources to retail load. However, it did

[3] Exhibit No. DPU 8.2 shows the list of the wholesale sales contracts included in the test period. It identifies those contracts priced at less than embedded cost and identifies the beginning and terminating dates of the contract.

not analyze the market to see how likely it would be that some 1800 MW of additional spare capacity would be available in the summer at peak when the entire western system peaks. Nor did it analyze the risk of this strategy. Indeed, the Utah Commission cited as one of its reasons for not acknowledging the RAMPP-5 report PacifiCorp's insufficient risk analysis.

Q. You said that management calculated that its load obligations in the future would decline. What evidence do you have to support this statement?

A. Another key assumption PacifiCorp changed in RAMPP-5 that affected planning was that it reduced its obligation to meet load by 10% over five years. It stated on page 2 of that report,

> The Company does not believe it is reasonable to plan for and build resources for load which it expects to lose within the next five years. Therefore, the company is adjusting its load forecast used in the model inputs for the new RAMPP-5 base case to reflect this expectation.

The combined impact of expected load loss and the wholesale balancing assumptions was to delay the need to add new resource. Indeed, PacifiCorp's prior report on load and resource balance indicated the need for a baseload plant in 2002.[4] The RAMPP-5 report with its two new assumptions identified no additional baseload resources for retail load until some time after 2012.[5]

Q. What conclusions do you draw from the historical intent of adopting normalized net power costs, a revenue credit for system allocated wholesale sales, and PacifiCorp's strategy to meet load obligations?

A. I conclude that PacifiCorp accepted a risk for a strategy that has backfired. PacifiCorp's decisions resulted in net power costs for the test period that exceed any actual net power cost

[4] PacifiCorp RAMPP-4 Update, 1997 IRP Report, December 1996, page 43.

[5] PacifiCorp RAMPP-5, December 1997, pages 137-138.

it has incurred over the last 12 years by about $200 million. It exceeds their own high price projection in the Centralia case by about $100 million. Exhibit No. DPU 8.6 is a bar chart that summarizes by year PacifiCorp's actual net power costs for the FERC accounts which are the subject of normalization.[6] Given the intent in adopting the revenue credit that contracts would either expire in a short time or cover their embedded cost, or as noted in the Wholesale Contracts Task Force report, not cause revenue requirement increases, I think that fairness requires that shareholders bear some of the cost of the increase in net power cost identified in this proceeding.

Q. What do you recommend that the Commission do in order to allocate the increased net power cost between customers and shareholders?

A. I recommend that the Commission normalize power costs as shown in the Division's nine adjustments. As noted earlier, Mr. Falkenberg will address five of these adjustments, Mr. Hayet will address two, and Mr. Burrup will address one. I propose the other adjustment.

Q. Would you please describe your proposed adjustment to net power cost?

A. Yes. I recommend that the Commission apply the criteria adopted in 90-035-06 governing the performance of long term wholesale contracts and impute revenues to the contracts that are at least halfway through their contract term and are priced *below* embedded generation and transmission cost. This is consistent with the 90-035-06 criteria as adopted by Commission order in that case as well as the language endorsed by the Wholesale Contracts Task Force Report that states "Pricing shall be structured such that over the life of the contract retail revenue requirement will be protected from increases resulting from resource acquisitions

[6] I have also included for comparison purposes the amount of net power cost included in rates ordered by the Commission in Docket No. 99-035-10 and the amount recommended by the Division in this proceeding.

needed to serve the wholesale contract."

I have identified these contracts in Exhibit No. DPU 8.2. For embedded cost, I relied on the cost of service study filed by PacifiCorp in this Docket. The average embedded cost at PacifiCorp's target rate of return at input (includes losses) is $37.60 per MWh. Since the average cost per MWh represented in the net power cost model for wholesale sales is at the sales level (excludes losses) I adjusted the wholesale contract prices down by 4.48% which is PacifiCorp's estimate of transmission level losses. I then identified the contracts with average price below $37.60 per MWh and computed revenues assuming a $37.60 per MWh average price. I then looked at the life of the contract and eliminated several contracts that were not yet halfway through their contract period. I believe this is consistent with the criteria adopted in 90-035-06 that "after a short time" the contract covers its embedded cost. I also eliminated contracts that were exchanges or otherwise connected to a purchase power agreement. Fourteen contracts remained. The difference in revenue between PacifiCorp's Type II normalized revenues and the adjusted revenues is $67 million. Thus, this adjustment reduces PacifiCorp's requested increase in total company net power costs by $67 million. On a Utah basis, using Division recommended allocation factors, this amounts to $25 million.

Q. Why did you impute revenues at embedded cost rather than marginal cost?

A. Although the 90-035-06 criteria also require each contract to cover its marginal cost and make a contribution to fixed cost, I have chosen to apply the embedded cost criterion because it is a fair sharing by customers of the increase in actual net power cost. I believe the marginal cost of supply for the test period was higher than the embedded cost. The reason for choosing the lower cost imputation is a matter of judgement that is not independent of the overall revenue requirement proposed by the Division in that the Division's case attempts to balance the interests of customers and the financial health of the company. Choosing the embedded cost imputation is also reflective of the fact that there is no formal guidance regarding the amount of sharing in an environment where marginal cost is higher than embedded cost . The embedded cost standard implies a 50-50 sharing of the cost of serving wholesale obligations. It is akin to putting underperforming contracts in a separate jurisdiction. Since most of PacifiCorp's net power cost increase is due to short term power purchases, using the marginal cost imputation could effectively allocate most of the cost increase to shareholders.

Q. Does the Division recommend a similar imputation for retail special contracts which are priced below embedded or marginal cost?

A. Not at this time. Early in this proceeding the Division reviewed Utah's special contract revenues in order to determine whether revenues were adequate going forward. Our review showed that all but three of these contracts will expire by the time a Commission order in this case would be issued. One contract will expire in December. The Division determined that the benefits of adjusting these contracts going forward was not worth the time and resources required to adequately analyze and defend the adjustments. Two contracts continue through to December 2002. The Division believes it can make recommendations regarding adjustments to these contracts outside of this general rate case. Finally, the Division intends to recommend tariff pricing for large customers in its cost of service testimony. In this way, the Division considers its resources better spent on pricing going forward for large customers rather than adjusting revenues in this case.

Q. You also recommend moving the Brigham City loads and revenues from Utah situs allocation to the FERC jurisdiction. Why?

A. There is no compelling reason that the wholesale customer Brigham City should be included in Utah retail loads. Brigham City is an all requirements customer and all of the other Utah all requirements customers are situs allocated to the Utah FERC jurisdiction. For consistency, I recommend that this contract be treated like the others. Exhibit No. DPU 8.4 is the top sheet that explains this adjustment. It changes Utah's allocation factors and reduces situs revenues to Utah by $2.4 million.

Q. In summary, what does the Division recommend for net power costs in this proceeding?

A. The Division recommends continued use of normalized net power costs with revenue credit. This policy places the risk of fluctuating power costs on the Company which has control over managing this risk. The Division also recommends reaffirming the criteria adopted in 90-035-06 to manage customer risk associated with the adoption of this policy. Finally, the Division recommends the Commission adopt all of the Division's adjustments to net power cost in order to reflect reasonable estimates of normal net power cost in the test period, with consideration given to allocation of the cost increase in net power cost between shareholders and customers.

Q. Does this conclude your testimony?

A. This concludes my prefiled direct testimony on revenue requirement. I will also provide testimony on the Division's position on Spread and Rate Design which I will file on June 15, 2001.